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 2023 to 2027 period. Hydro One has prepared this TSP in accordance with relevant sections of Chapter 2 (Revenue Requirement Applications) of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Applications, issued on February 11, 2016, with further guidance from Chapter 5 of the Filing Requirements (Consolidated Distribution System Plan Filing Requirements), issued on June 24, 2021 (together, the "Transmission Filing Requirements").

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. Similar information regarding Hydro One Transmission's General Plant assets may be found in the General Plant System Plan (GSP) under Section 4.0 of the System Plans.

2.0.2 FORMAT OF THE TSP

Consistent with the Transmission Filing Requirements, Hydro One's TSP is organized as follows.

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 life-cycle strategies.

TSP Section	Content Description
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 discussion on transmission reliability performance and reliability regarding 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 discussion on the transmission scorecard.
Section 2.6	**TSP Other Capital Planning Factors and Considerations** – This section details other factors which have informed the investment plan, including customer engagement and statutory and regulatory obligations.
Section 2.7	**TSP Investment Planning Process** – This section summarizes the information found in SPF 1.7 – Asset Management and 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 five-year period (2023-2027).
Section 2.9	**TSP Capital Expenditures – Trends and Variances** – This section assesses Hydro One's historical capital spending to previous OEB-approved funding and provides a ten-year view (2018 – 2027) of Hydro One's capital spending for its Transmission business.
Section 2.10	**TSP Capital Work Execution** – This section discusses the capital delivery process and Hydro One's approach to accomplish the proposed capital investment plan.

TSP Section	Content Description
Section 2.11	**TSP Material Investment Summary Documents** – This section includes detailed summaries of large investments (with forecast spending over $3M in any given year) over the 2023-2027 period in the OEB's System Access, System Service and System Renewal investment categories.

To assist parties in their review of the TSP, Hydro One has prepared a Table of Concordance found at Appendix A, which 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, 2020. Forecast costs for the 2023 to 2027 period are as forecast in Hydro One's 2023-2027 Transmission Business Plan (as presented in Exhibit A-03-01-01).

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SECTION 2.1 - TSP - OVERVIEW

2.1.1 INTRODUCTION

Hydro One Networks Inc. (Hydro One) has prepared a comprehensive five-year Transmission System Plan (TSP) for the 2023 to 2027 period.[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]

Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital, for a total of $7,258M, to respond to a range of asset and system needs, and to meet the customer service imperatives that are at the core of Hydro One's business mandate. 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. The resulting TSP is based on outcomes valued by customers and is consistent with their priorities and pacing preferences.

Hydro One's transmission grid is the backbone of Ontario's electricity system, serving 38 LDCs, 83 large direct-connected customers, and 135 generators (including nuclear and hydroelectric). As a result, Hydro One strives to provide safe and reliable grid operations on a 24/7 basis and accommodate load and generation growth. To achieve this overarching service mandate, the TSP will cost-effectively maximize risk mitigation and customer value while also mitigating rate impact.

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[1] Historical Years: 2018 to 2022.
[2] OEB, Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

Approval of this Application results in the following bill impacts on a transmission-only basis (discussed further in Exhibit H-10-01):

- The estimated total monthly bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month)[3] is a decrease of 0.3% ($0.43) in 2023 and an average annual increase of 0.3% ($0.39) on monthly bills over the five-year period.
- For a typical Hydro One GSe< 50 kW customer (2,000 kWh/month) the estimated total monthly bill impact is a decrease of 0.2% ($0.90) in 2023 and an average annual increase of 0.2% ($0.83) on monthly bills over the five-year period.

System Renewal investments account for 82% of Hydro One Transmission's 2023-2027 capital plan. These investments will manage and mitigate risks stemming from poor condition, inadequate performing, functionally obsolete or failed assets. The proposed System Service and System Access investments are non-discretionary and account for 10% of the total capital plan. The remaining 8% of the proposed capital plan are attributable to the General Plant investments. System Renewal, System Access and System Service investments are discussed below in this section (and detailed in Section 2.8) while General Plant investments are detailed in the General Plant System Plan (Exhibit B-04-01).

The key driver for System Renewal investments is the significant population of poor condition assets. The transmission system has 291 transmission stations (comprised of transformers, breakers and protection systems) and approximately 29,000 circuit-kilometers of high voltage lines (comprised of conductors and wood or steel support structures), many of which were installed 60 to 70 years ago and have been subjected to ongoing wear-and-tear and environmental exposure. Through its asset management process, Hydro One identifies assets that are in poor condition, pose an elevated probability of failure and must be managed through planned renewal to mitigate reliability, safety and environmental risks. The TSP investments target the most pressing needs (based on asset condition, criticality, performance, etc.) at a

[3] Typical Hydro One R1 customer without Distribution Rate Protection per O.Reg 198/17.

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 have been reasonably paced to address assets that are in poor condition, have inadequate performance or are obsolete including 3.3% of the transformer fleet per year, 2.5% of the breaker fleet, 3.4% of the protection fleet per year, 1.1% of the conductor fleet per year, 3.3% of the insulator fleet per year, 2.7% of the wood pole fleet, and to coat 1.0% of the steel structure fleet per year to extend their useful life. Investments continue the replacement of obsolete and poor performing air-blast circuit breakers that are installed at critical network stations connecting hydroelectric and nuclear generators.

System Access and System Service investments respond to mandatory service and system planning obligations, including (i) regional infrastructure needs to alleviate system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (ii) constantly evolving regulatory standards and requirements relating to planning, design, operation, and maintenance of Hydro One’s transmission system. Notably, the unprecedented growth in the Windsor-Essex region of Southwest Ontario is expected to double the region’s electricity demand in the next 5 years, requiring significant transmission reinforcements on Hydro One’s system at the direction of the IESO.

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

Table 1 - Material Transmission Investments and Customer Benefits

Investment/Description	Need	Main Customer Benefits/Outcomes
System Renewal Investment		
Network Stations Asset Replacement (T-SR-01) – 35 individual investments to address assets that are in poor condition, have inadequate performance or are obsolete at 30 transmission network stations at a cost of $994M over the five-year period.	Investments in network stations are driven by station asset condition (e.g. over 1 in 4 transformers (198 | 27%) are currently in poor condition), performance and obsolescence and are prioritized based on safety, compliance, reliability and environmental criteria.	Network stations are part of the transmission "highway" to safely and reliably transport electricity from major generation resources to over 5 million end-use customers across Ontario. By replacing assets that are in poor condition, have inadequate performance or are obsolete, Hydro One ensures continuous and uninterrupted access to reliable source of electricity in the province. Network stations form part of the North American bulk electric system and, as such, are subject to stringent planning, operating and reliability criteria and standards mandated by NERC and NPCC. The proposed investments ensure Hydro One remains compliant with all relevant requirements.
Air Blast Circuit Breaker (ABCB) Replacement (T-SR-02) - 11 investments that target the replacements of poor performing and obsolete ABCBs and other components at 9 transmission network stations, at the cost of $576M over the five-year period.	ABCBs are the poorest performing breakers in Hydro One's transmission system. In addition, ABCBs are obsolete technology; the lack of available spare parts poses operating challenges and increases maintenance costs.	ABCBs are installed at Ontario's most critical transmission network stations (e.g. Bruce, Lennox, Sir Adam Beck) that connect (i) nuclear and hydraulic generation stations with the total output equal to 30% of Ontario's electricity generation and (ii) international power flow to the states of New York and Michigan. By replacing ABCBs with modern technology, Hydro One ensures the integrity of provincial power flow, avoids generation bottlenecks and loss of production as well as secures import and export of electricity in and out Ontario.
Connection Stations Asset Replacement (T-SR-03) – 102 investments to address assets that are in poor condition, have inadequate performance or are obsolete at 94 connection stations at a cost of $1,877M over the five-year period.	Similar to network stations, investments in connection stations target assets that are in poor condition, have inadequate performance or are obsolete, some of which are 60-70 years old, at major connection stations such as Glendale TS, Bridgman TS, Fairbank TS that supply power to Alectra Utilities' and Toronto Hydro's customers (representing approx. 35% of all Ontario distribution customers).	Connection stations are a critical component of the transmission "highway" 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 (which include critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals, airports and transportation systems, schools and universities). By replacing assets that are in poor condition, have inadequate performance or are obsolete, Hydro One ensures that it continues to provide the electrical energy necessary to power the provincial economy and meet society's daily needs.

Investment/Description	Need	Main Customer Benefits/Outcomes
Transmission Line Components Refurbishment (T-SR-04 to T-SR-08, T-SR-13, T-SR-17) – 16 individual investments that target the refurbishment of 1,571 km poor condition conductors, and other capital programs that replace poor condition lines components such as wood poles, insulators, shieldwires at the cost of $1,919M over the five-year period.	Investments are driven by the need to refurbish or replace transmission line components that are in poor condition and have functionally deteriorated. The majority of circuits are located in public areas, where a failure of the poor condition assets pose significant safety risk to the public. This renewal work addresses radial line components located in Northern Ontario that, if failed, are likely to cause an outage.	Transmission lines are part of the transmission “highway” that safely and reliably transport electricity from major generation resources to over 5 million end-use customers across Ontario. Lines that are subject to replacement cross major roadways and highways, and at least one segment is located near school. Customers that are served by radial lines include municipalities, First Nations communities and businesses, large load facilities such as petrochemical processing facilities, mines and paper mills. By investing and replacing poor condition transmission line components, Hydro One ensures public safety, and continuous and uninterrupted access to a reliable source of electricity in the province.
System Access and System Service Investments		
Build Leamington Area Transformer Stations (T-SA-10)	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. Expand or build five new stations that will be in-serviced during 2023-2027, to meet Ontario’s growing electricity needs.
West of Chatham Transmission Reinforcement (T-SS-07)		
West of London Transmission Reinforcement (T-SS-09)		

Through Hydro One's mature capital delivery process based on strong oversight and governance and an experienced execution organization (see TSP Section 2.10), Hydro One has the ability to carry out the proposed capital plan and continue its successful track record in executing capital investments. In this regard, Hydro One has demonstrated the ability to successfully deliver large capital work plans and reduce the variability of capital expenditures and in-service additions using a skilled internal workforce and qualified third-party contractors (see TSP Section 2.09 Attachment 2).

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;
- 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, local distribution companies 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 TRANSMISSION SYSTEM

Hydro One's transmission system transmits electricity throughout the Province of Ontario. In 2020, Hydro One transmitted 132 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 its 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.

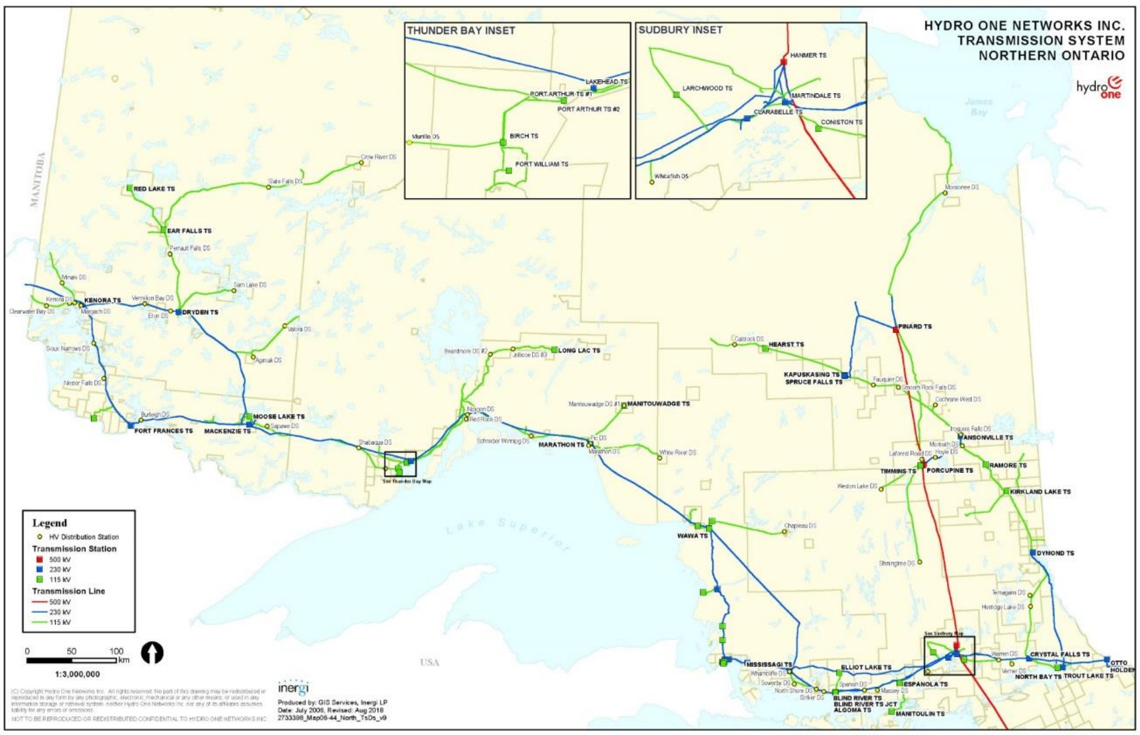

Figure 1: Hydro One Transmission System in Northern Ontario

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., Hydro One Sault Ste. Marie LP, Niagara Reinforcement Project Limited Partnership, and B2M Limited Partnership. It also interconnects with five neighbouring transmission systems in Canada and the United States (Manitoba, Quebec, Minnesota, Michigan and New York), enabling interjurisdictional electricity through 25[4] interconnections, as shown in Figure 3, below.

[4] The number of interconnections will increase to 26 as a result of the Lake Erie interconnection project (SS-01).

Collectively, these interconnections accommodate about 5,250 MW in imports and 6,020 in exports in the summer[5] months.

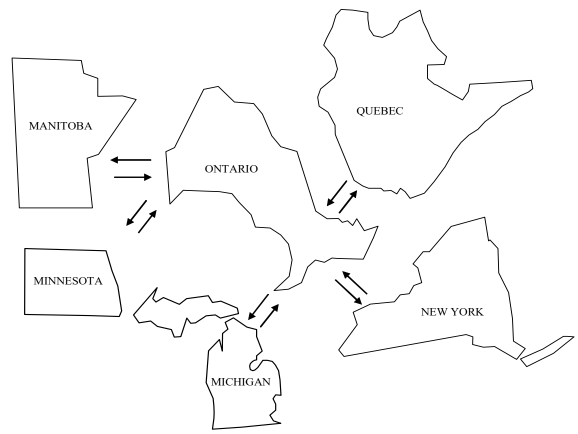

Figure 3: Existing Ontario Transmission Interconnections

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.

Transmission lines are comprised of overhead conductors (built above ground), 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 at customer load centres.

[5] From the IESO 2020 Annual Planning Outlook, Supplemental information, February 9, 2021. All transfer capabilities and related details on limiting phenomenon are based on best available information at the time of the 2020 APO development. These values may shift over time as new information and updated assumptions become available. All capabilities represent Transmission Transfer Capabilities with respect to Planning Requirements, and should not be interpreted as System Operating Limits.

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 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 real estate and 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 table below.

Table 2 - Hydro One's Key Transmission System Assets

System Assets	Total
Operating Centres	2
Transmission Circuits (Total Number)	527
Length of Overhead Transmission Lines (Total Circuit km)	28,552
Length of Underground Transmission Cables (Total Circuit km)	273
Transmission Stations (Total Number)	291
Installed Transformer Nameplate Capacity (MVA)	106,577

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	135
End Users (Large Industrial Customers)	83
Local Distribution Companies	38

Transmission connected generation customers represent almost all of Ontario's total generation capacity, including most of Ontario's hydroelectric generation facilities, all natural gas fuelled 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 those stations to shut down for extended periods, 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. Reasonable rates and reliable electrical service is a significant factor for large industrial customers deciding to locate and remain located in Ontario.

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

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 reliability and performance of Hydro One's transmission system include critical infrastructure such as 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.[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)

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[7] See https://www.emergencymanagementontario.ca/english/emcommunity/ProvincialPrograms/ci/ci.html
[8] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, p. 41.
[9] SPF Section 1.6 Attachment 1 – Customer Engagement Report, p 19.

transmission system.[10] This reliability framework is based on the NERC reliability standards adopted and enforced in Ontario by the IESO. NERC 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 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

[10] Hydro One applies the NERC definition of the BES that was approved by the Federal Energy Regulatory Commission (FERC) effective July 1, 2014.

[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.

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.

There are 90 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

Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital to respond to a range of asset and system needs based on a plan consistent with customer needs and preferences. Hydro One's proposed capital expenditures are summarized below by OEB investment category in Table 4 and Figure 4.

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

Table 4 - Forecast Period Capital Expenditure Summary ($M)

OEB Investment Category	Forecast Period (Planned $M) [13]					% of Portfolio
	2023	**2024**	**2025**	**2026**	**2027**	
System Access	79.4	70.9	59.8	36.5	50.1	4%
System Renewal	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0	82%
System Service	90.9	101.6	85.8	93.1	90.1	6%
General Plant (Transmission)[14]	146.8	124.0	114.2	115.9	105.0	8%
Subtotal	1,495.0	1,524.9	1,511.4	1,522.8	1,509.2	**100%**
Productivity[15]	-61.0	-61.0	-61.0	61.0	-61.0	
Grand Total	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**	

[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 2023-2027 forecast. Projects, currently under development, that meet these criteria and where the transmission lines portion of capital expenditures have been excluded are the Waasigan Transmission Line, the Chatham to Lakeshore Transmission Line and the Lambton to Chatham Transmission Line. Two additional investments that are expected include a transmission line from Longwood to Chatham (IESO letter expected in 2021) and a 20 km transmission line from Lakeshore to the Leamington area (Regional Planning report expected in 2021). Further information may be found in TSP Section 2.8. Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169).
[14] Details on General Plant expenditures are located in B-04-01 "General Plant Plan".
[15] Progressive productivity represents commitments made during the 2020-22 transmission rate application for 2022 that are sustained through the test period. Incremental productivity reductions for JRAP are applied to revenue requirement via productivity stretch factors, as described within the SPF Section 1.4.

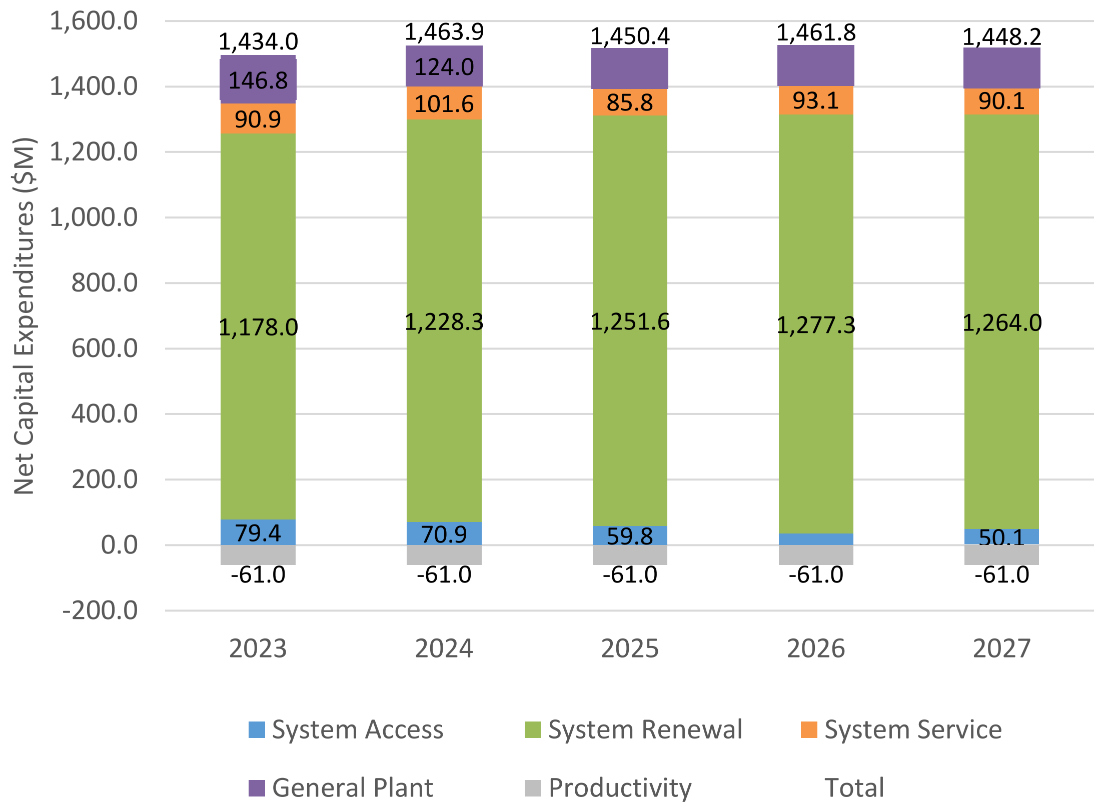

Figure 4: Forecast Period Capital Investment Summary ($M)

2.1.3.1 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. These investments account for about $593M of the gross capital expenditures for the five-year period. However, the majority of these investments are recoverable from customers in accordance with the Transmission System Code resulting in net capital expenditures of $297M or 4% of the total net capital expenditures over the five-year plan.

System Access investments are detailed in TSP Section 2.8 and the "SA" ISDs are included in TSP Section 2.11. Major investments for the 5-year period include the following:

- Hydro One plans to undertake $325M of gross capital work ($189M net capital after accounting for customer contributions) to connect load customers by building new or by expanding existing transformer stations to increase capacity and meet load growth (see TSP Section 2.11, T-SA-03, T-SA-08, T-SA-09, T-SA-10) and providing connections to customers (see TSP Section 2.11, T-SA-01), including the connection to six traction power stations for the Metrolinx rail electrification project (see TSP Section 2.11, T-SA-04). The expansion of the agricultural sector and unprecedented load growth in the Windsor-Essex region of Southwest Ontario is the most significant driver of expenditure in this subcategory, representing $129M (51%) of the net capital expenditures. The load forecast in the region is anticipated to double over the next five years, requiring three new load supply stations to connect and supply new customers in the region (see TSP Section 2.11, T-SA-10).
- Hydro One plans to undertake $18M of gross capital work related to generation connections over the five-year period. Since all the project costs in this category are recoverable from relevant customers, there is no net capital impact as a result of these investments. Generator customer connection work is required to connect generation customers at the transmission level and execute transmission system upgrades to enable such connections (see TSP Section 2.11, T-SA-06).
- Hydro One plans to undertake $61M of gross capital work ($45M net capital after accounting for customer contributions) related to secondary land use transmission asset modifications over the five-year period. These investments vary in size and complexity from year to year, and 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-ways (see TSP Section 2.11, T-SA-07).

2.1.3.2 SYSTEM RENEWAL

System Renewal investments account for 82% of the five-year net capital expenditures in this TSP. These investments are needed to preserve the performance of critical asset groups by addressing assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete or have failed, and to ensure safety, as well as to mitigate reliability and safety risks and maintain compliance with regulatory, environmental and reliability standards.

Over 10% of all major transmission assets are in poor condition, with two of these asset categories (transformers and conductors) experiencing increasing numbers of deteriorated assets compared to prior years with the remaining asset categories remaining relatively stable compared to prior years (see Figure 6).[16] Deteriorated assets are more likely to fail, resulting in unplanned outages that are more costly to address and may have widespread impact on service. The need to address such assets is one of the major factors driving the proposed System Renewal investments.

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 deteriorated assets including 3.3% of the transformer fleet per year, 2.5% of the breaker fleet, 3.4% of the protection fleet per year, 1.1% of the conductor fleet per year, 3.3% of the insulator fleet per year, 2.7% of the wood pole fleet per year, and to coat 1% of the steel structure fleet per year to extend their useful life. Despite the comprehensive assessment criteria used to determine the System Renewal needs, changing system conditions, unexpected failures, localized outage or generation resource constraints can materially shift investment priorities. The coordination of multiple changing factors and

[16] Transformers (116 units in poor condition in 2016, and 198 in 2020), breakers (499 in 2016 and 541 in 2020), protection systems (3267 in 2016 and 3397 in 2020), conductors (2643 in 2016 and 3874 in 2020), and wood poles (4832 in 2016 and 4693 in 2020).

priorities with customer and system needs has continually increased the complexity of project execution plans and it is expected to be a factor closely monitored to allow for adjustments during the 2023-2027 period.

System Renewal investments are detailed in Section 2.8 and the "SR" ISDs are included in Section 2.11. Some of the major renewal investments include:

- $1,570M over the five-year period through 35 investments that will replace network station assets that are in poor condition, have inadequate performance or are obsolete, which link major generation resources to load centers. Hydro One's network system forms part of the BES, and as such the proposed renewal investments are required to ensure continuous power flow throughout the province and to meet relevant IESO, NERC and NPCC criteria. Expenditures in this category address refurbishment work at major stations and replace Air Blast Circuit Breakers (ABCBs) through 11 investments. ABCBs are the poorest performing breakers in Hydro One's transmission system. These assets are installed at Ontario's most critical transmission network stations that connect nuclear and hydraulic generation stations that account for a total output equal to 30%[17] of Ontario's electricity generation (see TSP Section 2.11, T-SR-01 and T-SR-02).
- $1,877M over the five-year period through 102 investments that will replace connection station assets that are in poor condition, have inadequate performance or are obsolete, that connect network stations and transmission load delivery points. LDCs and large industrial facilities are among the customers served by connection stations. The LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users (see TSP Section 2.11, T-SR-03).
- $833M over the five-year period to replace poor condition lines assets including 1,571 circuit-kms, or 41% of the known poor condition conductors in the fleet. These conductor sections will be addressed through 16 investments. This renewal work

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[17] (11,607MW/38,944MW)x100%; https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook Reliability Outlook Report, March 2021.

sustains a variety of network and radial line connected customers, including large and small municipal, First Nations communities and businesses, large load facilities such as petrochemical processing facilities, mines and paper mills. Currently, 3,874 circuit-kms (14%) of Hydro One's conductor fleet is in poor condition, with another 3,329 circuit-kms (12%) exhibiting some deterioration (see TSP Section 2.11, T-SR-13).

- $1,086M over the five-year period to refurbish or replace various transmission line components (e.g. wood poles, insulators, shieldwires) that have been confirmed to be in poor condition. These components are integral parts of transmission line system required to enable and support the overhead conductor to perform its functions (see TSP Section 2.11, T-SR-04, T-SR-05, T-SR-06, T-SR-07, T-SR-08, T-SR-17).

In response to the IESO's planning outlook, the System Renewal investments will improve and ensure transfer capabilities and maintain system reliability. In particular, Hydro One plans to renew its stations facilities at the Bruce A and Bruce B switching stations that connect the Bruce A and B Nuclear Generating Stations (NGS). Hydro One has similar plans at Cherrywood TS which connects the Pickering NGS and Darlington NGS. Hydro One also plans to undertake renewal work at the Milton TS and Claireville TS which receive power coming from the Bruce NGS and serve as major hubs of the southern Ontario transmission system. Further details on these investments can be found in TSP Section 2.11, T-SR-01.

As further discussed in System Plan Framework (SPF) Section 1.6, 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. Through customer engagement, 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. As a result, Hydro One has planned its System Renewal investments in alignment with customer needs and preferences to ensure that transmission facilities are renewed in a timely manner and customer reliability is not jeopardized.

2.1.3.3 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. System Service investments account for about $488M of gross capital expenditures over the five-year period (or $461M net capital after accounting for customer contributions) or 6% of the total net capital expenditures. These investments are non-discretionary with the majority having been identified as a result of regional planning processes, IESO bulk planning studies or the 2017 Long-Term Energy Plan (2017 LTEP).[18] As the lead transmitter, Hydro One is actively involved in the regional planning process and the development of regional infrastructure plans for 19 of the 21 regional planning zones in Ontario.[19] As such, regional planning is a significant input in preparing this TSP.

System Service investments are detailed in TSP Section 2.8 and the "SS" ISDs are included in TSP Section 2.11. Major investments for the five-year period include the following:

- Hydro One plans to invest $214M of gross capital ($192M net capital after accounting for customer contributions) on inter-area capacity investments, which will provide new or upgraded transmission facilities to increase the transfer capability within Ontario and with neighbouring utilities (see TSP Section 2.11, T-SS-01, T-SS-02, and T-SS-03, T-SS-07 and T-SS-09). A significant driver of investment is the required reinforcements identified by the IESO as a part of bulk planning studies for the West of Chatham and West of London transmission systems. The IESO has directed Hydro One to develop new 230 kV lines between Chatham and Lakeshore (West of Chatham) and Lambton and Chatham (West of London) because of unprecedented growth in the agricultural sector in the Windsor-Essex region of Southwest Ontario and the need to ensure the necessary bulk

[18] The 2017 LTEP recommended a total of sixteen projects. Detailed discussion relating to those projects was provided in EB-2019-0082 Exhibit B-1-1. Most of the projects are expected to be completed by 2022. Only four investments are expected to occur over the 2023-2027 plan period and account for a net capital expenditure $22.8M.
[19] See Appendices 3 and 4 in the Planning Process Working Group Report to the Board – The Process for Regional Infrastructure Planning in Ontario, May 17, 2013.

transfer capability to support growth in load and generation.[13] The required station expansion work to facilitate these new transmission lines represents 38% of the expenditures in this category and are detailed in TSP Section 2.11 T-SA-07 and T-SA-09 for West of Chatham, and West of London, respectively.

- Hydro One plans to invest $234M of gross capital ($231M net capital after accounting for customer contributions) in local area supply to provide new or upgraded facilities to ensure area supply adequacy, and meet load forecast requirements in areas where existing transmission facility loading levels reach or exceed capacity (see TSP Section 2.11, T-SS-04, T-SS-05, T-SS-06, and T-SS-08).

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 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 5 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 2.10.

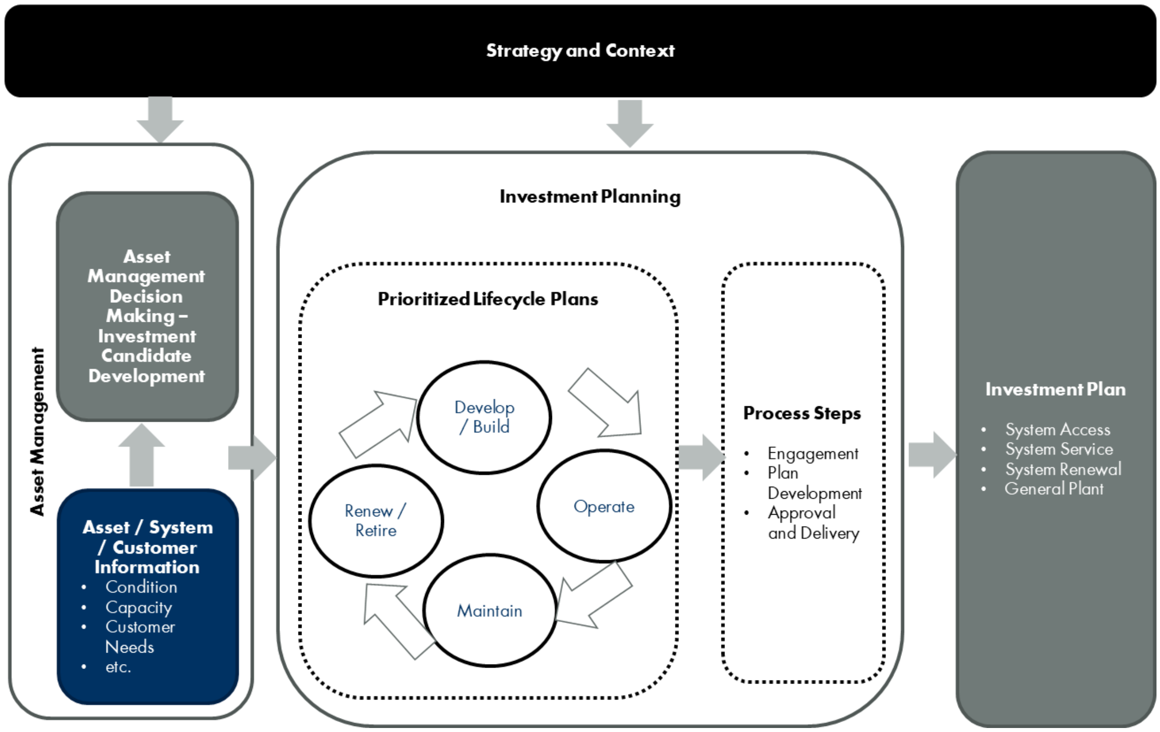

Figure 5: System Planning Process Diagram

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 2.11), each investment reflects explicit consideration for the achievement of RRF aligned outcomes.

Table 5 - Alignment of Plan Outcomes with RRF Performance Outcomes

Renewed Regulatory Framework Performance Outcomes		**Plan Outcomes**
Customer Focus	Customer Satisfaction	• Improve current levels of customer satisfaction.
	Customer Focus	• Engage with our customers consistently and proactively. • Deliver industry-leading customer service, in response to identified customer preferences.
Operational Effectiveness	Cost Control	• Focus on continuous improvement to enhance efficiency, productivity, and reliability.
	Safety	• Achieve top-tier safety performance and eliminate serious injuries.
	Employee Engagement	• Achieve and maintain employee engagement.
	System Reliability	• Maintain top tier Transmission reliability.
Public Policy Responsiveness	Public Policy Responsiveness	• Deliver on obligations mandated by government through legislation and regulatory requirements.
	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. • Manageable and stable rate impacts over the course of the planning period.

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 2019 and 2020, Hydro One retained Innovative Research Group to conduct Hydro One's first multi-phase customer engagement process to inform and refine the investment plans in this application.

Customer feedback in Phase 1 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. Overall, transmission customers prioritized reasonable rates and reliable service. In respect of reliability outcomes, they generally valued reduced restoration duration and fewer outages following extreme weather. With respect to trade-offs, a majority wanted the current level of investment for replacing aging transmission infrastructure to be maintained or increased, investment in a more reliable transmission system (either via ongoing renewal or as proactive investments), and investment in power quality improvement.

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

Customers were invited to complete an online workbook covering the draft plans for both the Distribution and the Transmission system. First Nation communities and the Métis Nation of Ontario were engaged through separate online workbooks and in-depth interviews, and municipalities and key stakeholders were invited to provide feedback through one-on-one interviews. Through Phase 2 of Customer Engagement, over 43,000 customers completed the online workbook. In general, customers expressed strong support for the replacement of aging and deteriorating transmission system assets to maintain the overall health of the system. Across all customer types, the “draft plan” was the preferred option for replacing transmission lines in poor condition and aging and deteriorating transmission stations.

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

Through its approach to asset management, Hydro One monitors its transmission asset population to determine the optimal manner of intervention. Hydro One tracks and evaluates its system assets, identify and define needs, and determine the appropriate timing for investments and maintenance activities in relation to asset condition and lifecycle management.

Hydro One performs continuous asset risk assessment (ARA), focusing on major equipment groups on the transmission system (i.e., transformers, conductors, breakers, and protection and control systems). Through the ARA, asset condition and other relevant factors (such as equipment obsolescence or performance) are evaluated against current and future requirements to identify asset risks for further screening and confirmation.

The above-noted System Renewal investments have been selected based on condition, performance and obsolescence criteria, including the renewal of poor condition network station assets and poor condition overhead conductors and related line components. As shown in Figure 6 below, over 10% of all major transmission assets are in poor condition, with two of these asset categories (transformers and conductors) experiencing increasing numbers of deteriorated assets compared to prior years with the remaining asset categories remaining relatively stable compared to prior years. These assets pose a material risk of adverse impact to Hydro One’s transmission system performance, public and employee safety, and statutory and regulatory obligations that Hydro One is required to comply with.

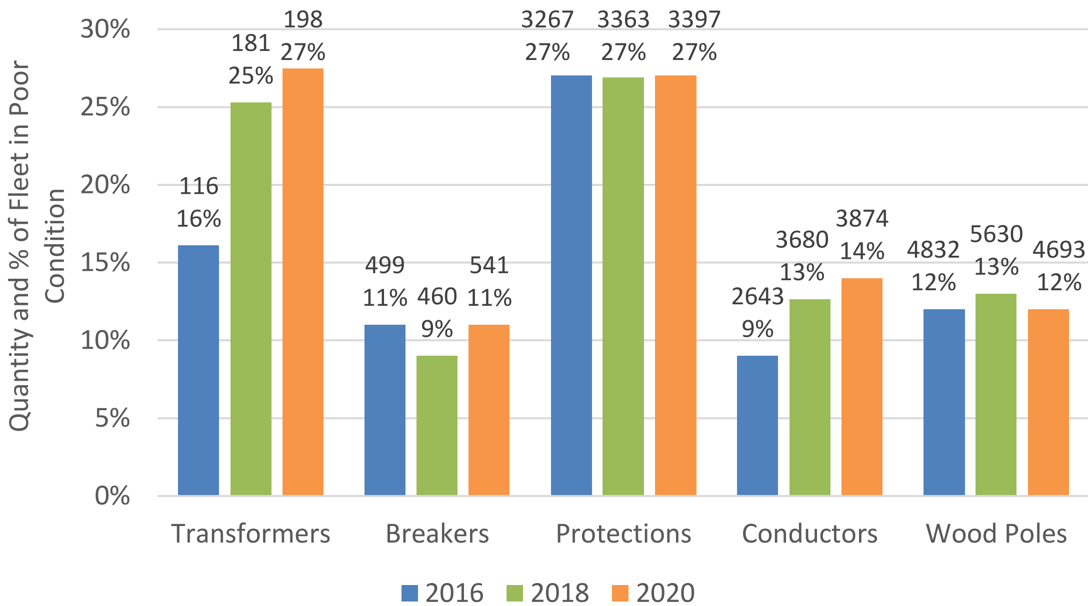

Figure 6: Transmission Assets in Poor Condition (2016, 2018 and 2020)

The proposed investments in this TSP do not target all poor condition assets and include assets with inadequate performance, assets that are functionally obsolete or assets that have failed. These investments addresses only the most pressing asset renewal needs required to ensure to system reliability and customer service. Residual risk is managed to establish a balanced portfolio to maintain system health and reliability while mitigating rate impact.

In addition to addressing the failure risk arising from deteriorated assets, Hydro One ensures that the transmission system delivers adequate and reliable supply to customers, meeting current and anticipated demands from the connection of load/generation customers and other distributed energy resources. 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. The above-noted West of London Transmission Reinforcement to relieve capacity constraints in Southwest Ontario (T-SS-08) is an example of a required investment to address significant system needs related to regional load growth.

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

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 the level of risk mitigated relative to the cost required.

In this regard, 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 taking into account the efficiency and total benefits of risk mitigated by each candidate investment.

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

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. As another layer of planning rigor and validation, challenge sessions take place among a broad set of stakeholders to debate the feasibility and merits of investments on the margin and to ensure that valuable investments (from both a risk and non-risk perspective) are included in the plan. The output is an investment portfolio that is subject to enterprise engagement with portfolio owners and the executing lines of business, so as to create a realistic and up-to-date plan (i.e., reflecting the latest cost estimates, schedules and investment scope) and account for operational and execution considerations (e.g., resourcing, material availability and outage feasibility).

2.1.4.5 ABILITY TO EXECUTE THE PLAN

Following approval by the Board of Directors, Hydro One's execution team takes ownership of the investment plan. The plan is reviewed and modified where appropriate throughout the execution phase as new information on asset condition and risks becomes available. Individual investments are further reviewed and approved through the business case process before proceeding to work execution.

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. As shown in TSP Section 2.5, the prior TSP has been delivered within 1% of the plan over the preceding three years. This performance is the result of a mature capital delivery process with strong oversight and governance and an experienced execution organization that completes the work using both

Hydro One’s skilled internal workforce and qualified external contractors. The capital delivery process is scalable to accommodate the necessary growth in capital work, is optimized to reflect the Hydro One work program and execution strategy, and includes a continuous improvement model to ensure that it is driving best practices. Hydro One’s capital project execution has been independently reviewed by UMS Group (see TSP Section 2.3, Attachment 1), which concluded that overall Hydro One has a mature project delivery process that performs well relative to industry peers.

Hydro One closely tracks year-to-date expenditures and accomplishments as well as projected year-end expenditures. As changes to investments or other circumstances occur during the year, Hydro One deploys a rigorous redirection process (see SPF Section 1.7) to reprioritize work based on new information and impact on projects’ expected value, timing, cost, customer benefits, and other factors.

SECTION 2.2 - TSP - ASSET INFORMATION AND LIFECYCLE STRATEGIES

2.2.1 INTRODUCTION

Section 2.2 presents information related to the major transmission station and line components that comprise Hydro One's transmission system. Information relating to 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, 2020.

Transmission station components presented in this section include: transformers (2.2.2.1), breakers (2.2.2.2), protection systems (2.2.2.3), automation systems (2.2.2.4), power system telecom (2.2.2.5), and other station assets (2.2.2.6).

Transmission line components presented in this section include overhead conductors (2.2.3.1), underground cables (2.2.3.2), structures and foundations (2.2.3.3), insulators (2.2.3.4), rights of way (2.2.3.5), shieldwires (2.2.3.6), and other line components (2.2.3.7).

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 and TSP Section 2.7. 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 impact on system operations or 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 assessment (ARA) process prior to any replacement being undertaken through particular investments. In this regard, condition assessments account for a range of considerations, including diagnostic testing results that gauge the deterioration of relevant components, history of repair that indicates a higher probability of failure, technical obsolescence due to out-dated design/functionality or lack of manufacturer support/spare parts, potential health and safety hazards, and operating conditions that are likely to cause undue stress on an asset and therefore hasten its physical deterioration. 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, years in service, availability of spares and vendor support, and/or obsolescence.

Asset condition is generally categorized as "good", "fair" or "poor". Assets with no or out-dated condition data are categorized as "needing assessment".

I. Good: These assets are new or show minimal signs of deterioration.
II. Fair: Assets that are experiencing deterioration and the condition of these assets is monitored for progression of further deterioration.
III. Poor: Assets that have deteriorated to a point where they can no longer provide the intended functionality or service.

As discussed below, expected service life (ESL) is useful as a trigger for condition assessments of older assets and a population-level indicator of asset demographics. It 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 transmission assets, the count and percentage of the population in poor condition at the end of 2020 and in 2016 and 2018 is shown in Figure 1 below. Two of these asset categories (transformers and conductors) have experienced an increasing number of deteriorated assets compared to prior years with the remaining asset categories remaining relatively stable compared to prior years.

1 As seen in Figure 1 below, over 10% of all major transmission assets are in poor condition.
2 Leaving poor condition assets unaddressed will lead to elevated risks for safety (e.g. failed
3 overhead line components falling onto publicly accessible areas), the environment (e.g.
4 transformer oil leaks) and reliability (e.g. failed components increasing operational risk or
5 resulting in unplanned customer outages in some cases). In addition, unplanned equipment
6 outages may impact Hydro One's ability to obtain planned outages, potentially resulting in the
7 cancellation and rescheduling of required capital replacement and maintenance work. This can
8 delay replacements, and preventative and corrective maintenance work, increasing the risk of
9 equipment failure that further compounds the aforementioned risks.

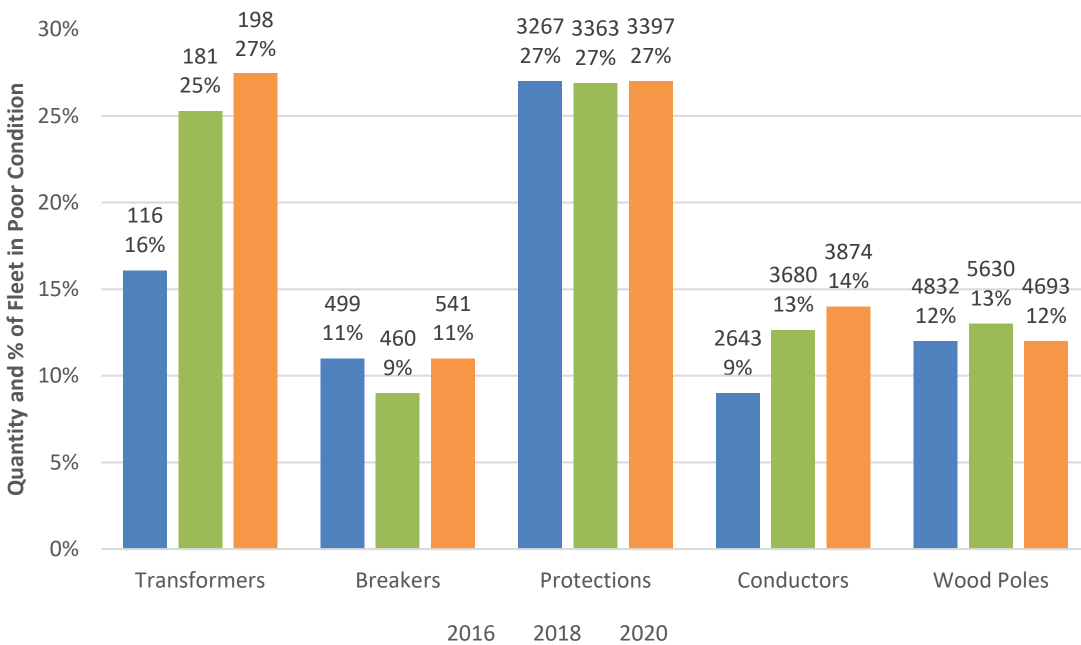

Figure 1: Quantity of Poor Condition Assets by Type

Asset Demographics

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 does not drive replacements, but can be a useful screening tool for gauging overall asset demographics at the fleet level and better focusing resources for condition assessments. However, in limited cases where the nature of particular assets (e.g. protection devices) means that actual condition cannot be tested, ESL-based lifecycle management is necessary and is in alignment 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). ESL also helps Hydro One better understand the potential level of testing/inspection requirements associated with aging asset populations and sheds light regarding the potential quantity of future replacements (but actual replacement is based on condition assessment) over the longer term.

Asset Performance

Transmission system reliability relating to equipment outages, as measured by assessing the frequency and duration and of unplanned (forced) outages caused by equipment; 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 and replacement work. The increased need for coordination of outages can result in changes in the execution plan, if work cannot proceed as scheduled. This in turn can result in increased pressure to replace more assets and need for adjustments and re-prioritization of projects. Further details on system reliability can be found in TSP Section 2.4.

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 actual condition assessment) 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 worsen over time before addressing poor condition assets through suddenly escalated capital investments. In fact, by the time reliability starts to deteriorate for dual-supplied DPs, equipment performance would have already unacceptably worsened, with an associated significant impact on customer delivery continuity, system operability, and potentially public safety. Even in the absence of such notable reliability deterioration today, 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 a 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.

Nonetheless, Hydro One does closely monitor DP and equipment performance to ensure that customers receive the appropriate level of service and that performance issues requiring urgent resolutions 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 classes of porcelain insulators (see TSP Section 2.2.3.4 below). In those cases, Hydro One will assess the need to take targeted planned action.

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.[1]

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, conditions, technical obsolescence, environmental and other factors);
- approach to optimize repair/refurbishment versus replacement;
- 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

[1] See TSP Section 2.7.

- consideration for standardization of assets to optimize lifecycle costs and improve productivity.

Asset-specific strategies are reviewed periodically with the 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 periodically 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 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, transformers asset utilization takes into account 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

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 1 below:

Table 1 - Transformer Fleet Description

	Transformer 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 100kV)
	**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 a single winding device that absorbs reactive power from the system as a way of controlling voltage and increasing the energy efficiency of the system.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Asset Demographics

As of the end of 2020, Hydro One had 721 transmission class transformers in service (with 743 transformer tanks), as summarized in Table 2 below. The transformer fleet grew by 5 units[2] since the last rate application. The number of transformers beyond ESL (which ranges between 40 to 60 years) remained stable since the last rate application at 176 transformers (24% of the fleet) and the average age of the fleet remained at 30 years.

Table 2 - Summary of Transformer Demographics

Type of Transformer	Voltage	Quantity	Average Age (Years)	ESL (Years)	Currently Beyond ESL
Step-down	500 kV	1	10.0	40	0
	230 kV -2 winding	188	33.7	50	32
	230 kV -3 winding	123	25.3	40	28
	115 kV -3 winding	110	29.9	40	44
	115 kV -2 winding	156	26.7	60	26
Auto	500 kV	42	28.0	40	12
	345 kV	4	43.3	40	2
	230 kV	88	37.9	50	28
Phase Shifter	230 kV	4	32.3	40	2
Regulator	230 kV	2	33.5	40	1
	115 kV	1	71.0	40	1
Reactor	500 kV	2	4.5	40	0
Total		721*	30.3	-	176

**Three single phase tanks in one operating designation only count as one transformer. There are a total of 743 transformer tanks.*

[2] EB-2019-0082 TSP 2.2 Table 3: quantity: 716, average age: 30, beyond ESL: 177.

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 an increase in the total number of "poor" condition transformers from 181 units (25% of the fleet) to 198 units (27% of the fleet) (see Footnote 3). Over the same period, the proportion of "good" condition transformers has decreased from 68% to 62%.

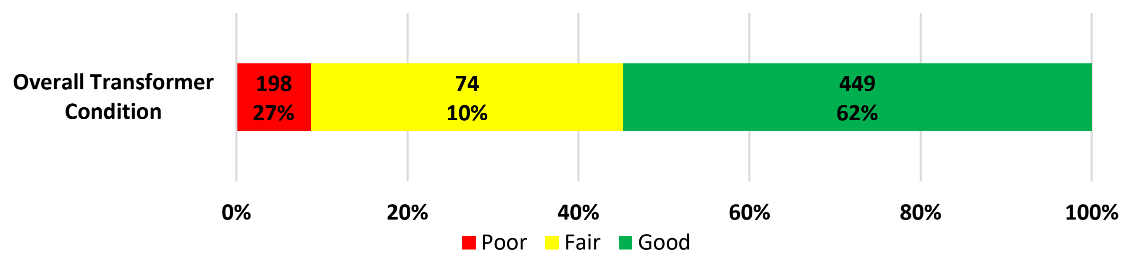

Figure 2: Transformer Condition

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. In addition, the assessment also takes into account other factors like defect reports and PCB contamination.[3]

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

[3] In the prior transmission application (EB-2019-0082, TSP Section 2.2, p. 8), the 122 (17%) transformers identified as being in poor condition reflected the main tank oil tests results only at a point in time, and not the other condition indicators as discussed below. Based on Hydro One's detailed transformer condition assessments, the number of poor condition transformers at the time of the prior application would have been 181 (as noted above). Similarly the 2016 values displayed in Figure 1 above have been updated to 116 based on the detailed transformer condition assessment whereas the values shown in the that rate application were solely based on the main tank oil assessment at a point in time (EB-2016-0160). It is important to note that Hydro One's approach for assessing transformer condition (and for prioritizing replacements) has not changed since the last rate application.

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 9% being classified as major leakers. Transformer oil leaks have increased by an additional 5% since the last transmission rate application. 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 721 transmission transformers (i.e., 743 transformer tanks) in service at the end of 2020, 198 transformers (i.e., 208 transformers tanks[4]) were deemed to be in poor condition based on a combination of main tank deterioration, oil leaks, cooling system failures, tap changer malfunction, defect reports, and/or PCB contamination.

[4] 208 transformer tanks correspond to 198 transformers (3-phase units).

Hydro One engaged Electric Power Research Institute (EPRI) to assess the conclusions of Hydro One's transformer condition assessment process in respect of the transformer main tank insulating oil condition indicator. EPRI assessed the main tank insulating oil condition of all 198 poor condition transformers (i.e., 208 transformers tanks - see TSP Section 2.3 Attachment 3). EPRI found main tank degradation in 155 transformer tanks and deemed them to be in deteriorated condition, 17 transformer tanks were found to be in marginal condition (i.e. close to EPRI's deteriorated condition threshold) based on their level of main tank degradation, and the remaining 36 transformer tanks were not deemed to have main tank deterioration. As noted above, while main tank oil test data is one of several key indicators of a transformer's overall condition, other relevant condition indicators result in the transformers associated with both the aforementioned 17 transformer tanks and 36 transformer tanks to be assessed in poor condition.

A large number of transformers in Hydro One Transmission's fleet contain polychlorinated biphenyl (PCB). Federal regulations require equipment containing PCBs above certain limits to be removed from service by 2025. As of December 2020, 73 of Hydro One's transformer oil-filled transformers that were manufactured pre-1985 require PCB remediation work including retrofills or replacements. By the end of 2020, it is estimated that 271 transformers still require sampling, the majority of which are transformer bushings. Further information regarding PCB remediation may be found at Exhibit E-02-02.

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 effecting customers may be found at TSP Section 2.5.

As shown in Figure 3 below, since 2014, the duration of transformer forced outages has been steadily increasing. This rising trend in outage duration has been driven by a combination of factors, primarily transformer failures which required extensive repairs or replacements that involved significant work. Notable failures affecting the duration of transformer forced outages in recent years include the Essa TS T3 (500-230kV autotransformer) red-phase failure in 2016 and Finch TS T2 (230-28k-28V step-down transformer) in 2018. Outage duration resulting from these two incidents is 193 (Essa T3) and 375 (Finch T2) days respectively. Every time one transformer fails and redundancy is lost for months, a subsequent failure of a companion can result in disastrous consequences to load and customers. Therefore, minimizing unplanned transformer failures it is of critical importance.

Transformer outages can be caused by a number of 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 condition.

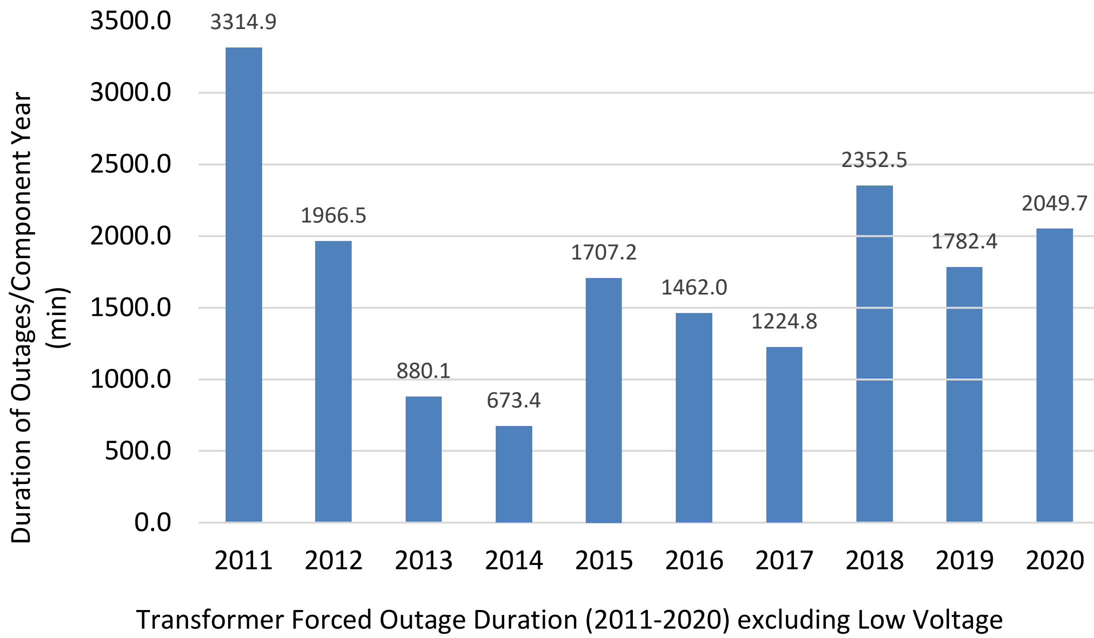

Figure 3: Forced Outage Duration of Transformers

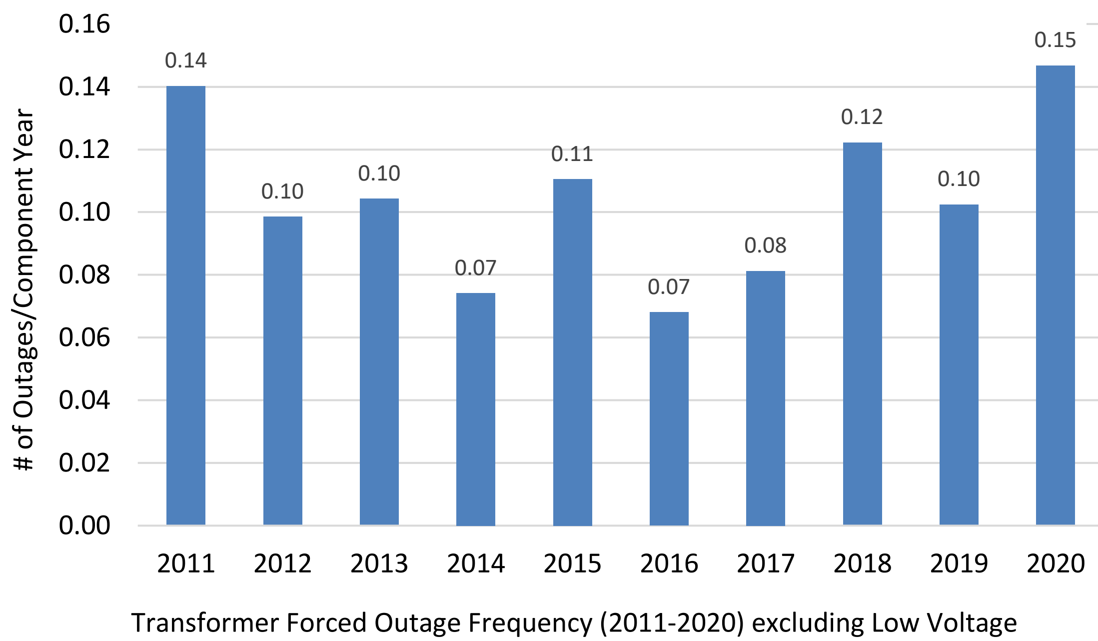

Figure 4: Forced Outage Frequency of Transformers

Since 2011, there has been an average of four transformer failures annually that require offsite repairs. These failures can lead to catastrophic consequences. For example, the major failure of Richview T7 and T8 in 2011 resulted in both transformers being engulfed in fire, producing smoke that severely impaired traffic on Highway 401 during rush hour.

When comparing the 2011-15 period to the 2016-2020 period, the failure rate of 500kV transformers has more than doubled from 1.43% to 3.29% as shown in Figure 5. Increased monitoring, as discussed further below, has been initiated to control the situation in coordination with the replacement plan in an effort to identify and address transformer issues before future failures. The failure rate of 115kV transformers has declined while the failure rate of 230kV transformers increased slightly over the same 10-year period. More frequent 500kV failures may be attributed to design and manufacturing deficiencies, and higher operating voltage and loading requirements.

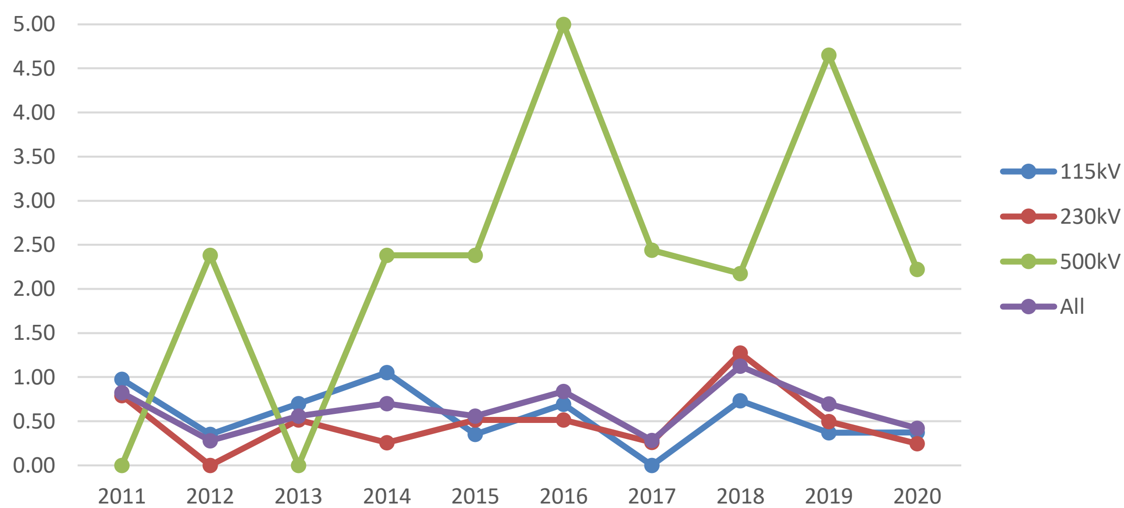

Figure 5: Annual Transformer Failure Rate, %

Table 3 - Number of Transformer Failures

Year	115kV	230kV	500kV
2011	3	3	0
2012	1	0	1
2013	2	2	0
2014	3	1	1
2015	1	2	1
2016	2	2	2
2017	0	1	1
2018	2	5	1
2019	1	2	2
2020	1	1	1

ASSET LIFE CYCLE

Inspection & 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.

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. Some transformer tap changers have been equipped with fibre-optic monitors that supervise the safe switching of the tap changer and provide leading condition indicators for any further inspections and maintenance. Thus, as the fleet of online monitoring devices expands, more condition data becomes available, allowing maintenance plans to be scheduled based on condition rather than set time intervals.

Hydro One will continue to install and upgrade online DGA monitors on larger and critical transformers, install fibre-optical thermal measurement systems on critical transformers and trial online partial discharge monitors that detect abnormal electrical discharges. In addition, new solutions to mitigate cooling system related problems are being evaluated. More details on this can be found it Exhibit E-02-02.

The following transformer Preventive Maintenance activities and schedules are followed:

Table 4 - 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)	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	As Required	Testing of the tap changer's performance, and the winding condition and connections and other internal faults

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.

Many critical transformers now include Online Dissolved Gas Analysis (DGA) 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. Online DGA 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 5 - 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.

Where remediation through corrective maintenance is not feasible, unplanned replacement shall be coordinated as described in the Investment Planning Redirection Process found at TSP

Section 2.7. Hydro One’s overall approach toward asset replacement (as well as refurbishment) is further discussed below.

Asset Replacement and Refurbishment

Transformer condition is a leading indicator to transformer performance. Hydro One does not run station 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 as well as cost comparison between refurbishment and replacement. Hydro One employs a model that derives the Present Value for three options: maintain status quo, refurbish, or replace. The model uses several factors such as maintenance cost, replacement cost, tax capital cost allowance, and the discount rate to select the appropriate option.

Transformers in poor condition are prioritized for replacement with consideration of those with known manufacturing defects, are obsolete, have higher repair costs or have undergone short-term repairs to restore its functionality but continue to pose a performance risk. Transformers that do not meet replacement criteria (particularly those that have reported severe oil leaks or verified PCB concerns) 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

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 mediums that have evolved over time. Hydro One's circuit breaker fleet has been summarized in Table 6 below according to the interrupting medium used, along with the production and environmental status.

Table 6 - Breaker Fleet Description

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

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

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

As of December 2020, Hydro One has 4,756 High Voltage (HV) and Medium Voltage (MV) breakers in service, as summarized in Table 7 below. The breaker fleet decreased by 18 units[5] since the last rate application as a result of replacing circuit breaker configurations with new configurations that require fewer breakers at certain stations.

As breakers approach their ESL, vendors may communicate their transition to limited support or complete obsolescence of these breakers, limiting spare parts and technical knowledge that are needed to sustain these breakers. The further beyond ESL a breaker is, the more likely it is that a vendor will transition to limited or no support. The number of breakers beyond ESL has significantly increased since the last rate application from 549 (11.5% of the fleet) to 763 breakers (16% of the fleet). The fleet is older overall with the average age increasing by 10% to 30.4 years. A large number of oil, air blast and metalclad breakers have already reached their ESL with an increasing number of breakers forecasted to reach ESL within the next decade.

[5] EB-2019-0082 TSP 2.2 Table 6: quantity: 4774, average age: 27.6 years, beyond ESL: 549.

Table 7 - Summary of Breakers Demographics

Type of Breaker	HV	MV	Total	Avg. Age	ESL	Currently Beyond ESL
	115-500kV	44-12.5kV			(Years)	
Oil Breaker	335	1,208	1,543	51.6	55	419
Air Blast Circuit Breakers	116	5	121	46.7	40	109
SF6 Breakers	827	1153	1,980	15.1	40	1
GIS Breakers	117	177	294	16.0	40	41
Metalclad Breakers	0	783	783	30.6	40	193
Vacuum Breakers	0	35	35	18.8	40	-
Total	1,395	3,361	4,756	30.4		763

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.

Condition is determined through preventive maintenance including diagnostic testing and inspections (discussed below). The condition of the breaker fleet is summarized in Figure 6. Since the last transmission rate application, the number of poor condition breakers has increased from 460 (9% of the fleet) to 541 units (11% of the fleet).

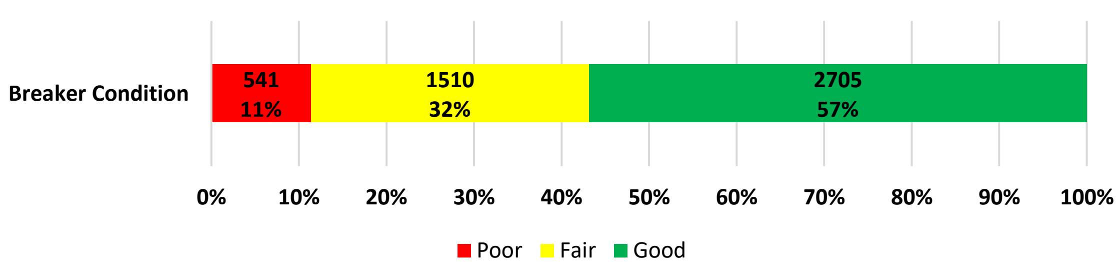

Figure 6: Overall Breaker Fleet Condition

Circuit breakers use a variety of interrupting mediums including oil, air and SF6 gas. In the case of air and SF6, 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 SF6 gas to leak out and lower the breaker's pressure. Concurrently, leaks create a path for moisture ingress. Either condition (lower pressure or moisture ingress) reduces 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.

ABCBs rely on high pressure air for their operation with multiple ABCBs being supplied from a common airline. Severe air leaks may be caused by degraded O-rings or safety valves that freeze in the open position in the winter, leading to the loss of air and subsequently, the loss of breaker control. Since multiple ABCBs are supplied from a common airline, a significant leak in one ABCB can affect the air pressure in another ABCB and may result in the removal or isolation of multiple adjacent breakers and high voltage circuits, thereby causing large load interruptions and generation bottling.

A large number of the circuit breakers in Hydro One's breaker fleet contain PCB. Hydro One is required to meet federal regulations requiring all PCB containing equipment above certain limits to be removed from service or remediated to less than 50 parts per million (ppm) by 2025.[6] By the end of 2022 all oil filled equipment in transmission stations manufactured prior to 1985 will be sampled. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements. As of December 2020, Hydro One has sampled 1,464 breakers. Of the breakers that still need to be sampled, 42 breakers are projected to contain PCB levels that require remediation. This projection is based on the rate at which Hydro One has been finding high PCB concentrations in the equipment sampled to date. Further information regarding PCB testing and remediation may found at Exhibit E-02-02.

[6] Planned completion by 2025. Refer to Exhibit E-02-02 for an explanation regarding the current plan.

SF6 is a common and effective dielectric medium used in a large portion of the breaker fleet. Due to leaks caused by O-rings (discussed above) and other gas piping components, SF6 leaks must be repaired. Some model types have known issues with leaks, for example certain medium voltage SF6 breakers (referred to as model SP, totalling 208 units in the Hydro One fleet). SP breakers have a known leak point on the bushing flange for which there is a repair procedure, but there is a subset of the SP breaker population (about 5% identified so far) for which these repairs are not effective, thereby requiring replacement.

Hydro One has 2228 breakers, or 47% of the overall fleet, that are considered obsolete, with approximately 143 breakers, or 3% 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 ABCB fleet, some first generation SF6 GIS circuit breakers and most types of 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 3% of the overall fleet.

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, which 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 at TSP Section 2.5.

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 increasing trend in the last five years, as illustrated in Figure 7 and Figure 8 below. This overall increase in prior years is primarily attributed to the number of ABCB-related forced outages. The recent decreasing trend in outage frequency referenced in Figure 8 and Figure 9 below, shows the effectiveness of ABCB replacements in recent years.

The relatively high forced outage frequency for a period of years starting in and around 2013 was predominantly due to the increase in ABCB air system control component failures. The ABCB population experienced the greatest number of air system component failures. In some cases, such failures led to breaker fail protection operations that forced the tripping (opening) of adjacent breakers. This can cause interruptions to circuits and busses, which could give rise to transmission customer outages. These performance issues have also resulted in multiple instances where generators were forced offline.

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. Other factors include condition, obsolescence, safety risks, exceeding nameplate rating, and environmental impact, as discussed in the Asset Lifecycle section below.

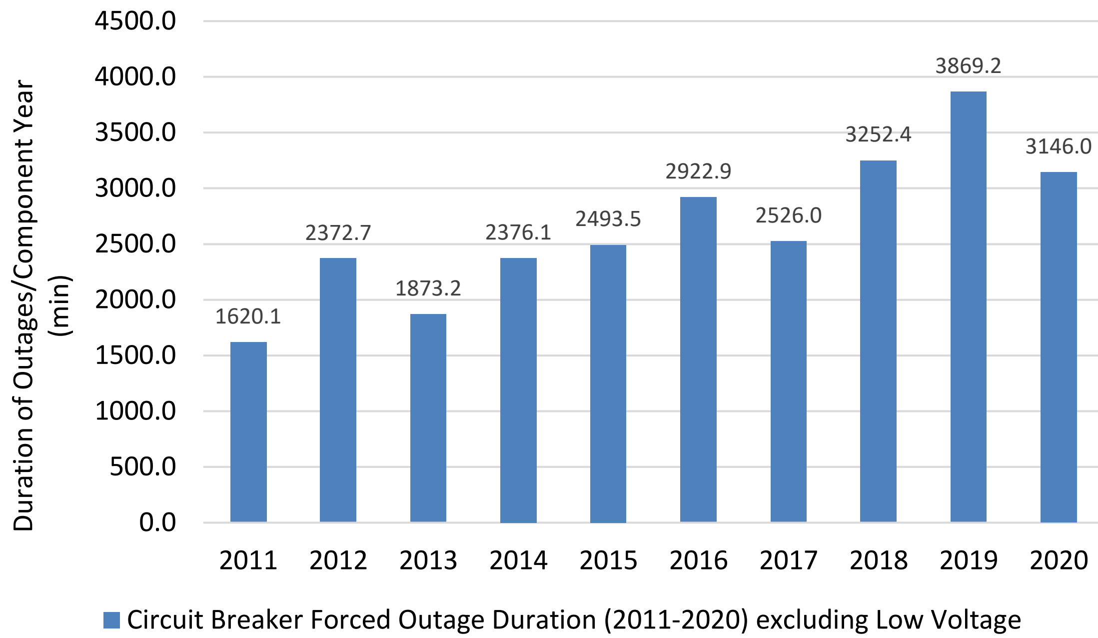

Figure 7: Circuit Breaker Forced Outage Duration

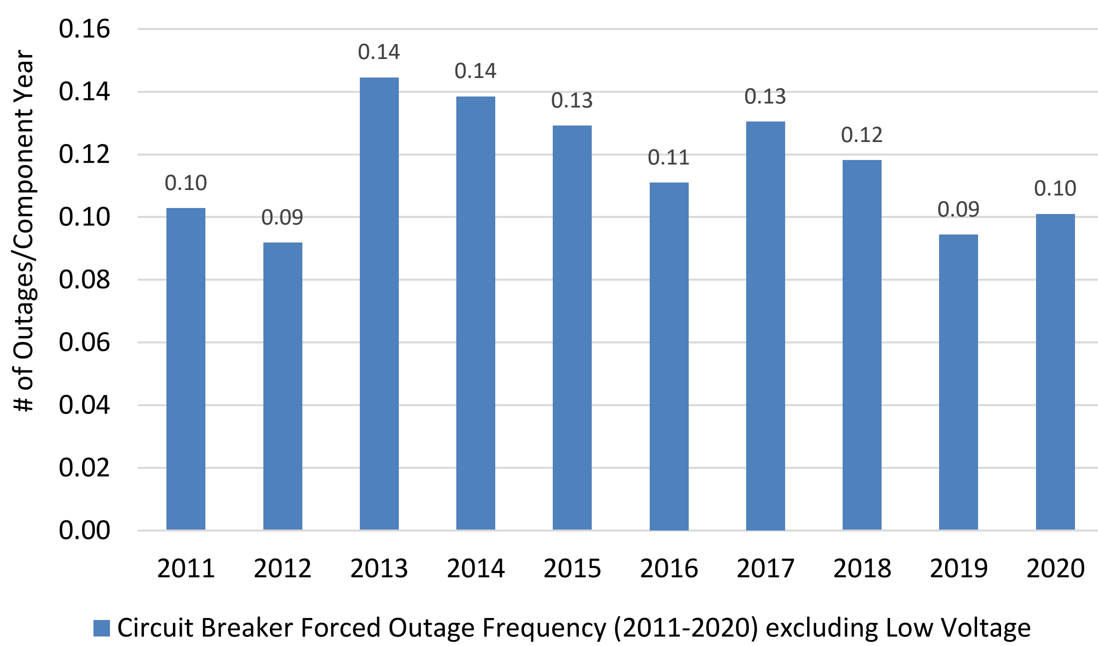

Figure 8: Circuit Breaker Forced Outage Frequency

Forced outage frequency by breaker type in Figure 9 below illustrates how the strategy of replacing the ABCBs has lowered their related forced outages in recent years.

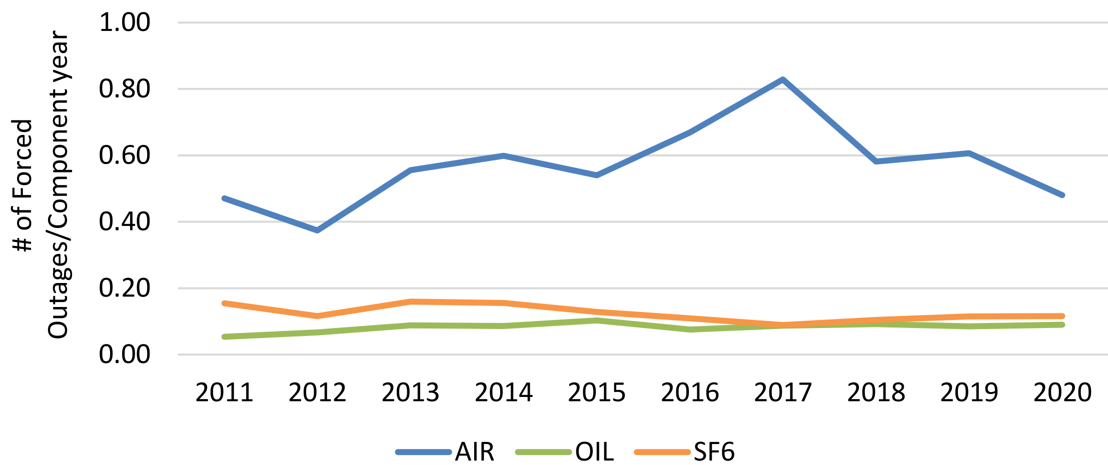

Figure 9: Summary of Forced Outages by Breaker Type

ASSET LIFE CYCLE

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 SF6 or containing PCB levels in excess of regulatory criteria). 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.

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. The following maintenance packages are generally applied to circuit breakers:

Table 8 - 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
Selective Intrusive (SI) Inspection	12-14 years or Condition based analysis	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.

SF6 is a colourless gas and conventional leak detection methods require the power equipment to be taken out of service, followed by the use of soap or bags placed over the suspected leak to look for bubbling from the leak, which can take many hours or days. Hydro One is exploring technologies to resolve SF6 leaks, such as the use of SF6 cameras, to detect leaks prior to taking breakers out of service. This may lead to reduced outage times and improved work planning.

Alternatives to O-ring replacements are being explored in order to reduce outage times, repair costs and minimize poor performance until the asset can be retired. Deteriorated O-rings can cause leaks of the insulating medium and possible ingress of moisture, leading to a degradation of dielectric properties. If feasible, alternatives to O-ring replacement, such as sealant injection, may allow for shorter repairs that are less labour intensive in nature.

First trip testers are being explored as a diagnostic tool to detect intermittent mechanical issues without removing breakers from service. The device can assist in diagnosing if breaker operating time is beyond applicable limits due to issues with the trip/close coil or main mechanism. It can also help detect the condition of the DC supply and the existence of any sticky or faulty circuit breaker auxiliary contacts.

Along with the new testing tools, Hydro One has started assessing X-ray inspections on breakers that helps to visualize internal components and their condition without doing intrusive maintenance. X-ray maintenance would significantly reduce the need for intrusive inspections and might be able to save significant resources, outage times and assist in spare management and ordering spare components as needed. The pilot project that was concluded in 2020 showed some promising results however Hydro One continues to consider how to economically incorporate X-ray maintenance with regular maintenance.

A non-operational data network is being established to collect and store data that is not required for day to day operations, such as diagnostic information. By facilitating the collection of such maintenance data, the operational data network would support more informed condition-based maintenance decisions. For more details on this investment, refer to GSP Section 4.11, G-GP-20.

Hydro One is continuing to explore monitoring on circuit breakers using dedicated electronic devices to collect breaker performance information automatically and more frequently. These monitors would reduce the need for manual condition assessments and support greater use of condition-based maintenance rather than time-based maintenance.

Asset Replacement and Refurbishment

Hydro One's approach with respect to the replacement of breakers is to target specific breakers with poor condition that pose system risks, as well as steadily pace investments driven by obsolescence caused by reduced vendor support for aged product lines. Early vintage GIS has begun to approach the point where vendors are declaring obsolescence, but, as discussed above, maintenance is still a viable option in the short term to deal with reliability and SF6 leak issues. Integrated GIS replacements are expected to commence outside of the current five-year planning period. Replacement of breakers is prioritized and paced through the ARA and investment planning process which places an emphasis on executing projects that will mitigate the most risk in a cost-effective way. A summary of the replacements is described below:

Table 9 – 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 • PCB regulatory compliance • 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 • 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

Hydro One's plan prioritizes breaker replacements based on obsolescence, vendor support availability, poor condition, environmental footprint, system criticality and safety risk.

To assess the changes in short circuit levels due to system upgrades and new or modified customer connection facilities, Hydro One performs project-specific short circuit studies and identifies any required breaker upgrades 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.

Replacing breakers that are based on obsolete technology eliminates maintenance activities that are no longer required for modern breakers. Examples include the elimination of ABCBs and the replacement of pneumatic mechanisms with simpler mechanisms.

Where spare parts are difficult to obtain or are no longer commercially available, sustainment of associated breaker fleets will be achieved by harvesting subcomponents from decommissioned units until the remaining fleet can be replaced. Where breakers exhibit unacceptable performance that cannot be resolved with a reasonable level of maintenance, these breakers will be targeted for replacement.

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[7] to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

2.2.2.3 PROTECTION SYSTEMS

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 10 below.

[7] Canadian Environmental Protection Act, 1999 - PCB Regulations SOR/2008-273.

Table 10 - Protection Fleet Description

	Protection Type	Description
	Electromechanical Systems	Electromechanical systems utilize the principles of electromagnetic induction to convert electrical energy to mechanical movement in order to detect faults.
	Solid State Systems	Solid State systems rely on integrated circuit technology to detect fault conditions.
	Microprocessor Systems	Microprocessor based protection systems, also known as Intelligent Electronic Devices (IED) 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.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Asset Demographics

Hydro One currently has 12,494 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 11 below, there are 3,397 (approximately 27% of the total population) protection systems operating beyond ESL. Notably, this includes 1,618 (over 90%) of the solid-state fleet that are 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 11 - Summary of Protection Systems Demographics[8]

Protection Type	Quantity	Avg Age (Years)	ESL (Years)	% Beyond ESL 2020	
				Qty.	% of Type
Solid State	1,784	36.5	25	1,618	91%
Electro-mechanical	3,077	40.1	45	1,359	44%
Microprocessor	7,633	8.8	20	420	6%
Total	12,494	20.5		3,397	27%

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. in terms of the provision of spare parts and repair services), 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.

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 40% 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

[8] EB-2019-0082: Table 9: quantity: 12,506, average age: 27.6 years, beyond ESL: 3,363.

compared to other utilities in North America. As shown in Figure 10, for the past 5 years, Hydro One's BES protection system misoperation rate is below the rate experienced by other regions in North America.

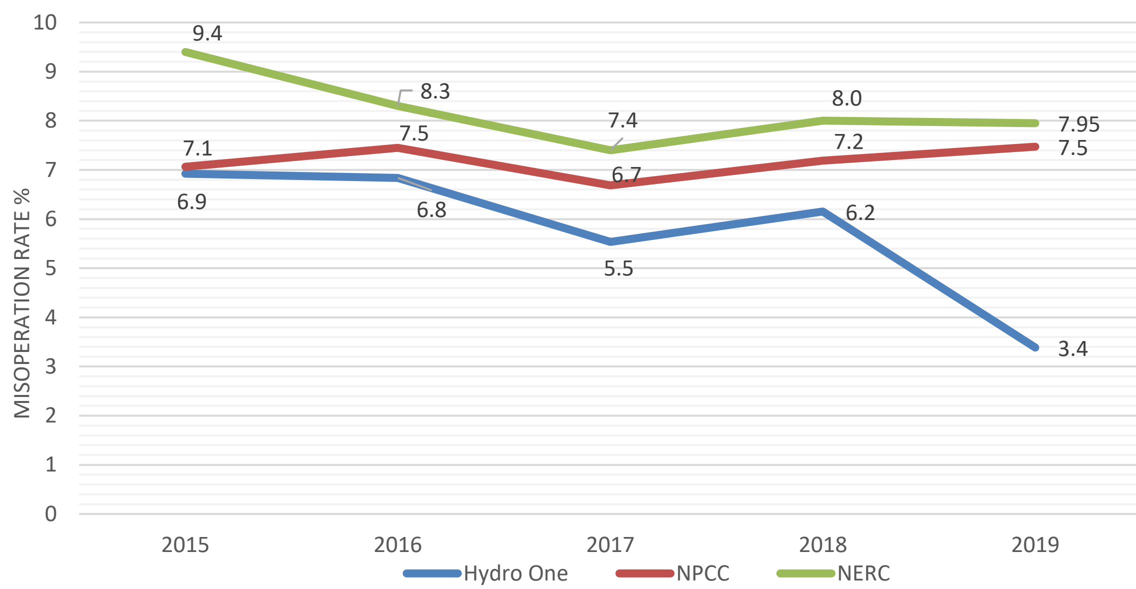

Figure 10: Misoperation Rate (%)[9]

Programmable Auxiliary Logic Controller (PALC) relays are a type of solid state protection system. They have shown an increase in recorded defects and trouble calls over the years due to deteriorating components within the relay. As a result, and due to the inability to obtain replacement units, PALC relays are considered high risk assets. Hydro One has been actively replacing PALC relays since 2014 and to date, approximately 300 PALC relays have been replaced. This has driven down the number of annual defects. Hydro One still has approximately 250 PALC relays in operation.

[9] 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.

ASSET LIFE CYCLE

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. A number of NERC and NPCC standards govern the protection system maintenance program, including:

- PRC-004 Protection System Misoperation Identification and Correction – 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 - 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 - Purpose of this standard is to ensure that Remedial Action Schemes do not introduce unintentional or unacceptable reliability risks to the BES.
- NPCC Regional Reliability Reference Directory # 4 – System Protection Criteria – This document provides the design criteria for bulk power system 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 condition. Routine testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon.

The testing frequency of protection systems that are part of the BES is governed by applicable mandatory NERC standards.[10] For the remainder of its 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. Since 2019, Hydro One began adopting different maintenance intervals for non-BES protection system. For example, where a new microprocessor-based relay is installed, its self-monitoring capabilities allow the maintenance interval to be extended, which is also reflected in NERC standards.

Additionally, for BES protection system, 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.

Historically, the maintenance plans were aligned with maintenance cycles under an initiative where maintenance was performed on defined groups of equipment with the intent to mitigate customer outage impact. The alignment of protection maintenance was reviewed to achieve more cost-effective delivery of the maintenance program, and many of the maintenance cycles have been extended to account for advancements in technology. For example, the increased self-monitoring capabilities of micro-processor relays allowed Hydro One to extend the

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

maintenance interval for non-feeder microprocessor relays from 8 to 10 years for regulatory compliance-driven maintenance. Table 12 below summarizes the preventive maintenance schedules for protection systems.

Table 12 - Preventive Maintenance Intervals

	Regulatory Maintenance (Required by NERC or NPCC)[11]			Non-Regulatory Maintenance[12]	
	Hydro One Maintenance Cycle (Years)		Maximum Allowed Cycle by NERC		
	Historical	From 2019		Historical	From 2019
Microprocessor Relays (non-feeder)	8	10	12	8	12
Electromechanical and solid state (non-feeder)	4	5	6	8	12
Microprocessor Relays (feeder) [13]	N/A	N/A	N/A	8	12
Electromechanical and solid state (feeder)	N/A	N/A	N/A	8	8
Breaker Trip Coil Tests (BTCT) [14]	4	5	6	N/A	N/A
Zone Test Tripping (ZTT)	4	8	12	8	8
ST3 - NPCC Directory #	5	5	5	N/A	N/A
Property Visual Inspection (PVI)[15]	N/A	N/A	N/A	3 or 8	3 or 8
Special Protection Transfer Tripping (SPTT)	4	4	6	N/A	N/A

[11] Regulatory maintenance is performed on a subset of Hydro One protection system assets (approximately 40%) that are part of the BES system.
[12] Timed maintenance covers maintenance of protections assets not included in BES system.
[13] Maintenance of Hydro One's feeder protections is not required by NERC standards.
[14] Tests performed on BES assets only.
[15] There are no regulatory requirements for visual inspections to be performed. Intervals of 3 or 8 years are selected based on the history of silver migration issues at a specific station.

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 which allows longer time windows for corrective work (>30 days).

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.

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, 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 poor condition 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 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 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.
- Technology 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.

The transition from obsolete electromechanical technology to new microprocessor based protective relays will result in a higher replacement rate going forward due to the significantly shorter ESL of newer relays. Electromechanical protective relays on Hydro One's transmission network typically operate between 40-60 years before needing replacement. The ESL of modern microprocessor protection relays has been estimated at 20 years and an increase in failures is expected after that time. In addition, systemic failures across certain models of protection relays have triggered a substantial increase in corrective maintenance and, in many cases, the need for large scale component replacements.

One of the greatest sustainment challenges for protection systems is the reduced vendor support time which has a significant adverse impact in terms of asset lifecycle management. The duration of vendor support continues to trend lower, which is largely driven by their own parts sourcing issues, faster technology changes as well as functional advances that manufacturers make for competitiveness. This problem is further complicated with ongoing changes to network connection standards that limit 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 has decided to proactively manage this issue by working with suppliers to gain extended support for their products in order to maintain the ESL for microprocessors at 20 years. Every year of asset life retained represents a deferral of planned capital investments.

Notwithstanding the increased costs for compliance obligations, replacing older style relays with modern protections can partially offset those other increasing 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. Old 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, resulting in decreased OM&A costs associated with preventive maintenance.

Further, there might be other efficiencies to be gained through greater integration and application of new functionalities (i.e. functionalities that were previously built in but not utilized due to a lack of certain required enabling systems). Multiple initiatives, such as Remote Fault Data Collection and Distance to Fault Analysis, have already been rolled out to seize the opportunities that newer technologies are providing. Once fully implemented, these initiatives will allow Hydro One to utilize features already built into the relays to increase the ability to react to system events and/or reduce OM&A costs. For example, for every protection system operation, Hydro One dispatches field staff to download fault data and pass it to engineers for analysis. By being able to remotely access fault data from the Intelligent Electronic Devices (IEDs), engineers will be able to directly obtain this data, thus reducing the cost associated with field staff dispatch.

2.2.2.4 AUTOMATION SYSTEMS

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 such as:

- Local and remote real-time monitoring, control and troubleshooting facilities for Hydro One field staff, control center staff 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 cyber security functionalities such as system event monitoring, authentication, authorization, logging and accounting; and
- Supporting the fulfillment of regulatory obligations.

Hydro One's automation assets consist of legacy and modern technological vintages. Legacy automation components primarily consist of Remote Terminal Units (RTU). RTUs are based on the concept of physical wiring and the digital conversion of electrical signals delivered by wires, generally for a single function or application. These systems utilize relatively slow communication connections and employ a variety of protocols.

Modern automation equipment is network enabled to utilize high-speed communications and has a smaller physical form-factor, exponentially higher computational capabilities, and a greater ability for integration with the Network Management System (NMS) as compared to its legacy counterparts. Information is conveyed through standard protocols which shift previous manual labour work related to hard wiring, towards skilled programming capability.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Asset Demographics

There are over 18,000 components and devices in service to support automation functionalities of Hydro One's Power System Monitoring and Control (PSMC). 38% of the automation system population is of the modern vintage type, while 62% is of the legacy vintage type.

Hydro One uses ESL of the different device vintages as a trigger for replacement assessments to investigate an automation device. Factors used in the ARA include the risk of its potential failure with respect to reliability and safety, spare availability and availability of vendor support. 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 automation devices plays an important role in the assessment for replacements of automation systems and devices. 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 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 automation systems, outlined in Table 13 below, is classified according to their vintage and is based on generally accepted industry practices and Hydro One's experience.

Table 13 - Automation System Expected Service Life

Automation Vintage	Expected Service Life
Legacy (copper-based)	20 years
Modern (IP-based)	15 years

There is a wide range of automation device vintages and types. Legacy devices include mainly two types, RTU and Programmable Synchrocheck Relay (PSR). The earliest vintages of RTUs are Quindar and Motorola RTUs; these devices have been in service for over 30 years and they are beyond ESL. Hydro One currently has 1005 RTU in-service. Approximately 7% of the RTUs (77 units) are Quindar and Motorola and are beyond ESL. PSRs have also been in-service for over 30 years and are beyond ESL. There are over 80 PSR in the system. Modern device types include LMC/LCC, gateways, routers and switches. The ESL for modern devices is mostly triggered by the end of vendor support, which is approximately 15 years on average based on Hydro One experience. More details on legacy and modern automation assets and replacements are explained in the following sections.

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 has been tracking the condition of automation equipment on the basis of performance, including relevant defect reports, trouble calls, and potential need identifications with the objective of determining future work programs.

Asset Performance

Automation system performance is primarily determined based on automation asset defect reports. Legacy equipment causes most of the defect occurrences and presents higher risk to the reliability of the network than modern equipment, as can be seen from Table 14.

Table 14 - Summary of Defect Reports (2011-2020)

Year	LEGACY			MODERN			
	RTU	PSR	Transducer	LMC/LCC	Gateway	Router	Switches
2011	674	69	29	52	12	4	2
2012	555	39	20	43	34	20	9
2013	577	48	14	71	30	17	10
2014	431	39	29	67	38	19	19
2015	384	39	31	78	56	16	18
2016	478	44	16	195	63	24	20
2017	912	8	3	208	63	31	43
2018	465	14	6	136	98	21	82
2019	750	32	12	92	97	37	94
2020	673	36	8	80	86	35	74
Total	**5899**	**368**	**168**	**1022**	**577**	**224**	**371**

Based on the statistics presented above, legacy systems have experienced defects four times more often than modern automation systems within the past decade. Legacy equipment makes up 75% of the total defect occurrences, with RTU having the highest number of defects. This is expected to trend upward as the fleet continues to degrade with age.

ASSET LIFE CYCLE

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.

Legacy automation equipment and subcomponents are strategically planned for replacement to ensure operational availability. Modern automation equipment has embedded self-monitoring capabilities to provide performance alerts for appropriate corrective actions to be taken.

Asset Replacement and Refurbishment

To ensure reliable functionality, Hydro One plans to manage legacy equipment obsolescence through timely replacement. The average ESL for legacy devices (copper-based) is 20 years based on generally accepted industry practices and Hydro One's experience. Some of Hydro One's legacy technology and design has been in service for over 30 years. Risks and costs increase as more of the legacy devices reach or exceed their ESL. As Hydro One modernizes its automation fleet though the deployment of station Local Area Networks (LAN), there is no longer a need for RTU installations. Modern solutions are IP-based with flexible scalability to match the company's needs.

Modern devices (IP based) have an average ESL of 15 years. Hydro One is currently evaluating changes in controls design architecture to maximize device functionalities and achieve system optimization. Many existing deployments were designed with legacy technologies that provided extra capacities or redundancy than required to meet reliability requirements. As some legacy technologies are discontinued and replaced with modern industry offerings, reliability requirements (for example, the redundancy requirement) will be met with reduced redundancy using modern technology.

The benefit of replacements is to increase standardization across the modern automation system fleet. Moving away from different legacy variations will allow activities to be streamlined from a work management and lifecycle management perspective. Modern automation devices have far more powerful computational capabilities, allowing the consolidation of functionalities that were previously provided by multiple devices. As part of its automation asset lifecycle strategy, Hydro One will work with device vendors to streamline support for automation devices.

Legacy Automation Equipment

Legacy automation equipment contributes to about 75% of total defect reports. Components degrade over time, which can adversely impact the performance of the legacy automation equipment. This is primarily a concern with legacy systems along with the lack of vendor support and limited ability to provide replacement components. Hydro One plans to prioritize problematic installations on the basis of statistics relating to failure/defect rates.

RTUs are expensive and labour intensive to install, modify and maintain. The equipment is generally built for a single function/application and does not offer much flexibility. From a communications perspective, these legacy systems utilize relatively slow, serial, point-to-point connections and employ a variety of protocols. Since the legacy devices do not have self-monitoring or self-diagnostic capabilities, it is not feasible to monitor the condition of the RTUs. The failure of a legacy RTU can cause a significant outage, in the case that like-for-like replacement is not feasible due to part obsolescence, and because a new device using new technology takes time to be installed and commissioned. Hydro One is replacing the legacy RTUs strategically to mitigate this risk.

PSR provides synchronizing capabilities for Hydro One substation breakers at 230 kV and above, and in some special cases where there is generation, at 115 kV. The synchrocheck philosophy was adopted by Ontario Hydro and consists of a centralized solution where only one device, the PSR, is responsible for the synchrocheck function of all breakers at a station. This was a legacy decision and implementation, which remains intact today. PSRs have been in-service for over 30 years. These relays have a very high failure rate and require specialized expertise and tools to configure and are single sourced due to their proprietary nature. Currently Hydro One is investigating potential replacement solutions in the market to replace the PSR devices.

Modern Automation Equipment

In comparison to protection, the automation world has seen significant advancements over the past decade. Hydro One is undertaking opportunities to further modernize and bring improvements to operational efficiency, reduce operational risks, and cost containment. The following are examples.

Local Maintenance Computers (LMC) and Local Control Computers (LCC) exhibit high maintenance costs and require frequent software patching and updates. Hydro One is in the process of phasing out these computers and is replacing them with modern solutions. LCCs are being removed and the same functionality is provided at the station gateway. This simplifies the design and reduces the number of equipment to install and maintain by substituting multiple LMCs with a simpler solution in compliance with the NERC Critical Infrastructure Protection (CIP) standards. Hydro One expects to minimize lifecycle costs and address generic operating system vulnerabilities related to these computers. Through removal of LMC and LCC, the same functions are performed by the station gateways which maximize the functionalities and benefits from a single device.

Hydro One's SCADA network consists of approximately 40 hub sites that are used to facilitate communication between remote stations and control centres. They are no longer necessary as the communication protocols have been consolidated and the ability to communicate directly between a station and control centre now exists. Hydro One will be converting to the Direct SCADA architecture with the intent of removing the hub sites. Removal of hub sites eliminates one level of data concentration in the data communication between the substation and the control centre, and maximizes station LAN functionality to communicate directly to control centre. Implementing Direct SCADA will provide improved reliability, performance, operational visibility and productivity as well as reduced costs. In addition, compliance obligations relating to NERC CIP standards will no longer be required as the hub site equipment is removed.

Hydro One is currently implementing a Transmission Non-Operational Data Management System to decrease costs by reducing maintenance, improve system availability, improve efficiency and automate dispatching of field resources. The system utilizes modern devices and architecture to perform multiple monitoring activities for power system primary equipment. The system will enable the automatic collection of non-operational data (e.g. not used for day to day operations, but can relate to asset condition) at the substations to be processed in real-time and captured through a centralized enterprise system for further reporting and analytics. A key expected benefit of the system is the support of condition-based maintenance activities.

2.2.2.5 POWER SYSTEM TELECOM

ASSET DESCRIPTION / PURPOSE

Power System Telecom includes communication systems, infrastructure, and leased facilities that enable 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:

- Utilizes 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 Hydro One Telecom, an affiliate of Hydro One, for operational services for Hydro One's telecommunication network that include 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 utilized for protection systems 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 is used as backhaul for the provincial mobile radio system. The network topology is such that stations are connected in the form of rings to provide redundant communication links that can stretch up to hundreds of kilometres long across the province.

The SONET network utilizes multiplexer equipment composed of two vintages: (i) the first generation initially deployed between 1998 and 2007 and (ii) the second generation from 2004 onwards. In addition to the multiplexer equipment, the SONET network includes microwave radios, optical amplifiers and 48Vdc backup power supplies for communications equipment. There are certain segments of the SONET network that are made up of microwave links as opposed to fibre connected paths. These obsolete microwave links have created capacity/bandwidth limitations on a typical SONET ring topology.

Fibre Optic Cable Infrastructure

Hydro One utilizes fibre optic cable infrastructure including Hydro One owned/operated aerial fibre optic cables and fibre strands acquired through IRU to support Hydro One's communications network. Aerial fibre optic cable is primarily comprised of: (i) Optical Ground Wire (OPGW) technology with strands of fibre embedded inside the shieldwire mounted on top of high-voltage transmission structures and (ii) All-Dielectric Self-Supporting (ADSS) fibre cable that is 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 which may be subjected to a very high voltage rise when a fault occurs on the power system, thus 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.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Hydro One currently owns approximately 4,136 microprocessor based communication devices, 1,152 ancillary communication equipment, 149 radio communication towers, 143 mobile radio base stations and approximately 2,178 km of fibre optic cable that, combined with 1,700 km of third-party fibre acquired through IRU, 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 15 shows the ESL in years for each asset type.

Table 15 - Summary of Power System Telecom Asset Demographics

Telecom System/Asset Class	Asset Type	Quantity	ESL (Years)	Currently Beyond ESL
SONET Communication Network	Multiplexers	267	15	125
	Digital Radios	22	15	22
	Optical Amplifiers	32	15	23
	48 VDC Batteries	272	10-20	25
	48 VDC Chargers	270	20	71
	OPGW	2,017 km	40	0
	ADSS	161 km	15	161 km
Power Line Carrier Systems	PLC Radios	424	20	211
Teleprotection Terminal Devices	T1 Multiplexers & Tone Devices	3105	20	331
Microwave Radio Systems	T1 Radios/ Sub-T1	286	15	12
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	611	30-50	309
Provincial Mobile Radio System	Radio Base Stations Equipment	143	20	143

Hydro One utilizes the 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.

<u>SONET Transport Network</u>

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 have become increasingly harder to find. The majority of SONET equipment failures are associated with the first vintage of multiplexer equipment (Vintage A MUX) as shown in Figure 11, which has experienced increasing failure rates. These failures have resulted in multiple PSTS 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 Ontario Grid Control Centre loses visibility of the status of the equipment). In turn, this 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 customers to a less reliable configuration due to the SONET network's state.

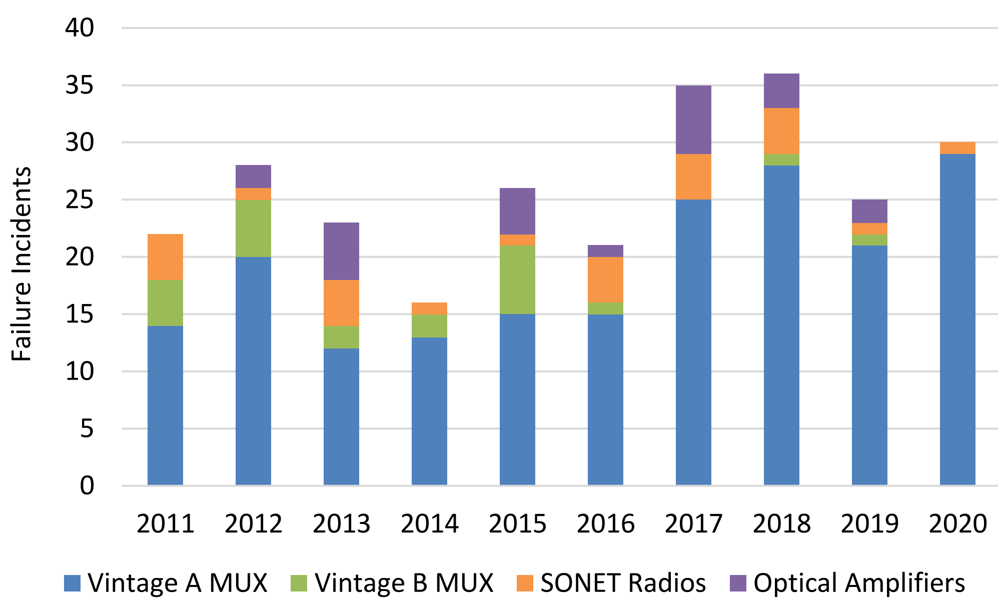

Figure 11: Failure Incidents for SONET Equipment

Hydro One has experienced degraded performance in recent years by many of the microwave radio systems (which are currently being phased out on the system) utilized in the SONET communication network that have experienced failures to render multiple PSTS unavailable until repairs were carried out. Due to the age and performance of these systems, and the significant risk they pose to the reliable operation of the transmission system, more frequent preventive maintenance is currently being carried out until they can be replaced.

In addition, 48Vdc batteries are critical components for the reliable operation of the SONET equipment and the batteries' conditions and performance degrade significantly with age. Hydro One plans to minimize the number of batteries that exceed ESL and is monitoring the condition of those that remain on the system. Certain types of 48Vdc charger units used in conjunction with 48Vdc batteries in the Hydro One fleet are prematurely failing before the end of their ESL due to internal component failures and thus require replacement. Hydro One is targeting and prioritizing these known problematic units along with those that exceed ESL for replacement, with consideration to their historical performance and vendor support availability.

Fibre Optic Cable Infrastructure

The ESL of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL is 40 years for OPGW and 25 years for ADSS. Historical performance shows that mechanical stress on ADSS fibre cable installations has prematurely reduced the cables' life span. In the case of ADSS cables, at the time when they were first installed by Hydro One, there was limited research available to fully understand the design principles, maintenance requirements and operational risk related to ADSS cables. Since then, historical performance has shown that a combination of these factors have contributed to unusual mechanical stresses on ADSS cables, as well as some of the early ADSS cable failures, resulting in its ESL being lowered to 15 years.

In terms of the reliability of OPGW, third party provided leased fibre routes have historically performed significantly worse than Hydro One-owned OPGW sections. This is because leased fibre routes tend to be installed on public road allowances, on wood poles, or along railway tracks which make 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 North/North Eastern Ontario) which was built using 100% third party provided fibres Figure 12 shows the historical occurrences of fibre breaks for each SONET ring.

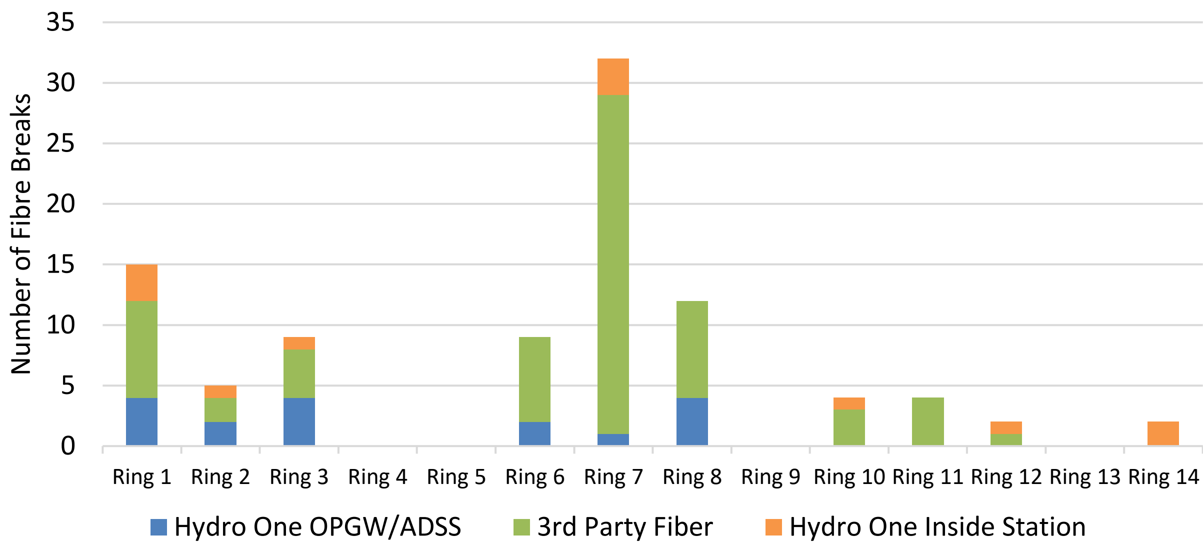

Figure 12: Fibre Breaks by SONET Ring (2011-2020)

<u>Power Line Carrier Systems</u>

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 60% of Hydro One's fleet of PLC radios have exceeded their ESL, are no longer supported by the manufacturer and are considered technologically obsolete. As shown in Figure 13 below, these vintages of PLC radios have been contributing to the majority of the defects that Hydro One has experienced on its PLC systems.

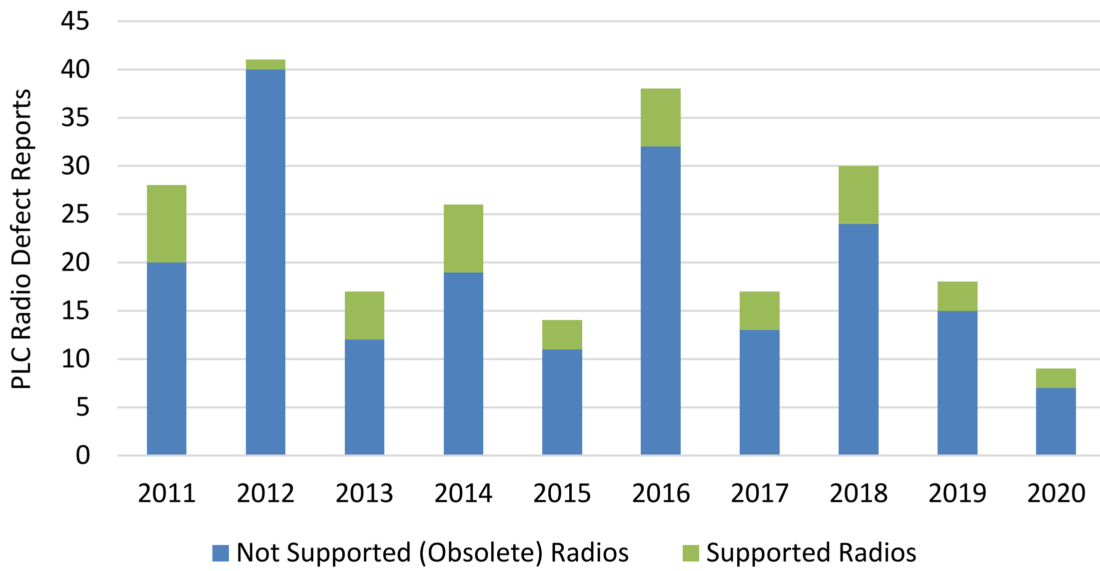

Figure 13: PLC Radio Deficiencies

Failure of the outdoor passive PLC equipment is significantly less compared to the indoor PLC radios. Since 2011, there have been a total of 10 failures or defects associated with outdoor PLC equipment compared to an average of 24 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 to be 20 years. Approximately 50% of T1 access multiplexers deployments were installed as part of the analog microwave replacement program that occurred between 1998 and 2007. The majority of these devices will reach ESL over the next five years. Inventory reports also show that approximately 23% of tone devices deployed have exceeded their ESL.

High Voltage Protection Systems

Neutralizing transformers (NT) have been deployed in Hydro One’s system since the 1950s. They make up 51% of the HVI equipment that have reached ESL (between 30-50 years, as per Table 15). Other HVI equipment (i.e. optical isolators, isolation transformers) is fairly new.

Considerations that help establish the ESL for NTs include degraded insulation, underrated NTs and the overall physical condition of the NT.

<u>Microwave Radio Systems</u>

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. None of the sub-T1 microwave systems 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, 39% 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.

<u>Provincial Mobile Radio System</u>

The provincial mobile radio system includes 149 base stations and approximately 2,000 radios that connect the control centres to fixed interim control centres, radio-equipped fleet vehicles and hand-held portable devices spread across Ontario.

The radio technology deployed for the exiting PMRS is technologically obsolete. The equipment is no longer manufactured or supported, and is considered beyond ESL. It is anticipated that Hydro One's strategic spares will be exhausted by 2023, and without the ability to replace defective equipment, this poses a risk to maintaining transmission system equipment and/or restoring power in remote areas in a safe and timely manner.

ASSET LIFE CYCLE

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.

Inspection & 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 Preventative Maintenance

Hydro One maintains and field tests all communication system devices to verify that they are functional and meeting 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, 48Vdc backup power supplies at certain sites (those identified by the IESO that are critical for restoration of Ontario's transmission system) are maintained as per NPCC Directory 8 (System Restoration) requirements.

More specifically, preventative 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 48Vdc 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 to verify their integrity (condition including rusting, leaking, equipment connections) and that they do not pose a risk to reliability and 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 which include visual inspections for signs of excessive wear and other abnormal conditions of the cable, as well as 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 four months and maintained/re-verified every six years while self-monitoring devices with remote alarming capabilities are maintained on a ten year interval. These maintenance intervals are more stringent than regulatory requirements to mitigate the risk of non-compliance by providing some buffer to account for cases where regulatory maintenance cannot be achieved as originally scheduled due to 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 keeping track of failure rates and determining maximum and minimum stock levels of Power System Telecom equipment to ensure adequate operational spares, Hydro One also proactively monitors the equipment that have been discontinued and are no longer supported by manufactures. Similar to other utilities, Hydro One is presented with “last buy opportunities” for strategic sparing of certain equipment, where Hydro One will purchase spares as appropriate in order to support the current installed base**.**

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 are facing 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 ceased 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 poor condition or obsolete equipment from the asset base while also working with suppliers to extended 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:

- Advancing its plan to replace the obsolete SONET network based on the selected technology as the majority of first generation equipment exceeds ESL and have limited vendor support;
- Sustaining and phasing out obsolete and poor performing Power System Telecom assets that have reached their ESL. This includes ADSS type fibre cables, obsolete PLC systems, teleprotection terminal devices, HVI equipment and microwave radio systems;

- Assessing 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 life-cycle optimization as well as reliability and regulatory requirements as dictated by NERC and NPCC;
- Extending third party IRU contracts where Hydro One ownership of fibre is not economical; 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 projects, and line refurbishment programs 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 and PMRS infrastructure replacements will be 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. This will allow Hydro One to seek efficiencies by utilizing existing Power System Telecom infrastructure while maintaining reliability associated with Power System Telecom Services.

<u>Replacement of SONET Network</u>

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. The phasing and replacement plans are currently being developed, with the replacement of SONET terminal equipment on Rings 1-9 beginning in 2023.

<u>IP-Based Communications for Teleprotection Applications</u>

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.

New IP-based technologies are being investigated by many utilities and regulatory bodies (e.g. NPCC, CIGRE) to migrate existing telecommunication services to newer IP-based services. Guidelines and migration paths are being developed. However, it is left up to the individual utility to assess their readiness and establish a migration path which best suits their situation. Hydro One is testing and validating the solution with the vendor to move away from legacy carrier-based leased services. Hydro One also actively monitors industry developments relating to the feasibility assessment and testing of new IP-based technologies.

<u>Expansion of Fibre Optic Cable Infrastructure</u>

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 growing need of connecting new stations;
- Displace obsolete technologies such as microwave and PLC; and
- Reduce ongoing OM&A costs by installing Hydro One owned facilities and moving away from leased services, where economical.

In the short-term, Hydro One’s primary focus is to displace SONET microwave links, leased facilities and third party IRU fibre with OPGW primarily, where economically feasible. Hydro One will also systematically phase out poor performing ADSS cables from its asset base. In the long-term, Hydro One will expand and/or sustain the fibre footprint by installing new OPGW.

New Mobile Radio System

The infrastructure sustainment needs of the PMRS are being addressed by work around base station shelters and communication towers. The planned mobile radio replacement project will:

- Examine available technologies such as radio over IP, satellite-based system, trunked radio system and integrated solutions to the existing hand-held and in-vehicle units used by field staff;
- Study the technical and economic feasibility of each of the viable technologies, proof of concept, and include a look at future operating costs; and
- Review required infrastructure development to ensure necessary coverage is provided prior to new system deployment.

2.2.2.6 OTHER STATION COMPONENTS

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. Other high-voltage (HV) and medium-voltage (MV) power equipment assets include switches, capacitor banks, reactors, instrument transformers, insulators, and surge arrestors.

Table 16 - Summary of Other Power Equipment

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.
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.

<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 17 - Summary of Ancillary Equipment

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 stations service transformers, AC/DC breakers, AC/DC switches and AC/DC transfer schemes. Station service equipment provide power to circuit breakers and protection and control equipment as well as auxiliary equipment such as fans, pumps, heating, lighting, etc.
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 ABCB. 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 18 - Summary of Civil Infrastructure

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 1920's.
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 river, 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, etc.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Hydro One has over 27,000 individual Other Station Components present in transmission stations, as summarized in Table 19.

Table 19 - Other Station Component Demographics

Asset Type	Quantity
Other Power Equipment	
HV/MV Switches	13,965
HV/MV Instrument Transformers	8,130
HV/MV Capacitor Banks	370
Ancillary Equipment	
DC Batteries & Chargers	863
AC/DC Station Service Equipment	1,238
High Pressure Air Systems	428
Civil Infrastructure	
Buildings	823
Infrastructure	251
Fences and Gates	391
Spill Containment	420
Fire and Security systems	43
Sites and Yards	637

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. Switch failures rarely have a significant system impact in terms of customer outages or even a momentary short-circuit fault. 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 though cancelled maintenance work, and delays and added cost to capital projects.

The demographics for switches have been presented in Figure 14.

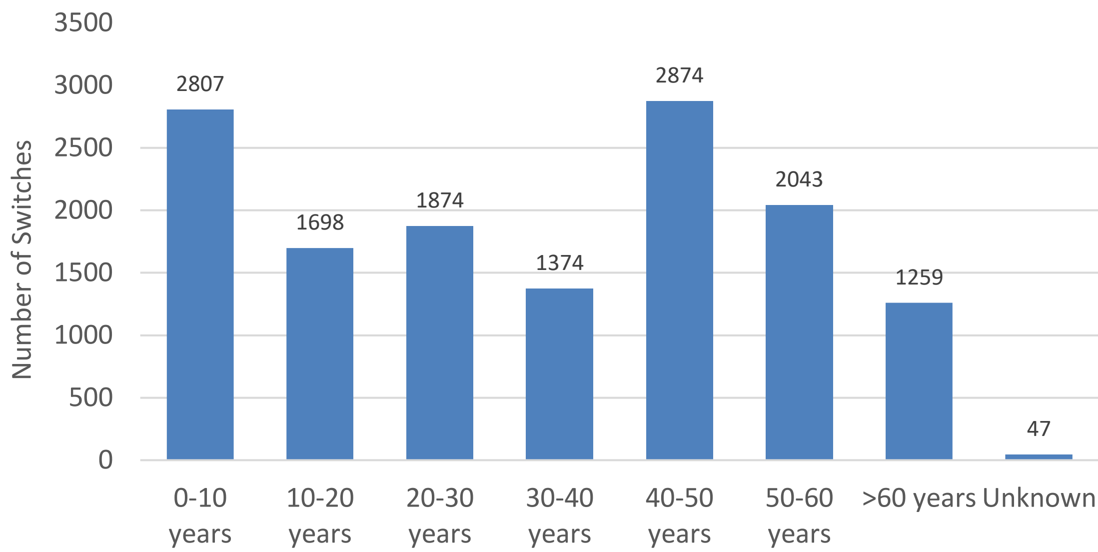

Figure 14: Demographics for HV and MV Switches

Approximately 6300 (45%) of the HV and MV switches are over 40 years old, with an ESL ranging between 40 to 50 years. Currently, 25% of the switch fleet is responsible for the majority of recorded defect reports. While there are few defects in new devices (switches under 10 years old represent 20% of the population but only 5% of the correctives), the rest of the defects are evenly distributed throughout 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. 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 370 capacitor banks, with a median age of 23 years. Capacitor banks are made up of dozens to hundreds of sealed capacitor units, each with tens of capacitive elements. The banks have unbalance monitoring systems connected to SCADA to indicate when there have been a significant number of failed elements, and that several capacitor units or external fuses need to be replaced.

Other Power Equipment - HV/MV Instrument Transformers

Hydro One manages more than 8,000 free-standing instrument transformers out of which approximately 5,000 are High Voltage Instrument Transformers (HVIT) and 3,000 are Medium Voltage Instrument Transformers (MVIT). The fleet of HVITs and MVITs measure voltage and current for various purposes, such as monitoring the state of the grid, detecting faults and metering usage.

Ancillary Equipment - AC/DC Station Service

Hydro One manages more than 1200 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.

Ancillary Equipment - DC Batteries and Chargers

Hydro One manages 863 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 40 years for battery chargers. 12% of batteries and 3% of chargers are currently beyond ESL. 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 currently manages HPA systems at 8 transmission stations that use ABCB, including 47 compressors, 46 dryers, 275 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.

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.

Asset Inspection & 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 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 initiating a new program of 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, broken insulators, degraded structures and bulging or leaking units, which are addressed through corrective maintenance.

With respect to instrument transformers, as these devices 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 AC/DC station service equipment (such as transfer schemes, 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

Batteries are a maintenance intensive item that may see improved reliability, safety, and maintenance cost benefits from enhanced monitoring systems. Enhanced battery monitoring of conventional lead acid batteries are being assessed for installation to provide maintenance, safety and reliability benefits. This will also adhere to applicable compliance requirements.

Hydro One maintains DC batteries and chargers by verifying functional and performance criteria according to regulatory standards governed by NERC PRC-005-06 and NPCC Directory 8. 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. 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, managing individual station environmental compliance approvals and any effluent testing/monitoring required in being compliant with the Ministry of Environment, Conservation and Parks.

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.

With respect to HVIT and MVIT, units containing PCB contaminated oil will be replaced prior to 2025 to meet compliance with federal regulatory requirements. In addition, it is expected that a further 800 free-standing CTs will be removed in conjunction with the ABCB replacements as most of the CTs on newer breakers are installed around the breaker bushing.

Ancillary Equipment

As ancillary systems are assessed to ensure compatibility with new station assets and regulatory compliance, more frequent and stringent maintenance are expected to be required. Inspection work in advance of integrated replacement plans will identify when certain ancillary systems will not deliver safety and reliability benefits required for the new station asset arrangements and upgraded equipment.

With respect to AC/DC station service equipment, refurbishment is considered if a report indicates serious degradation.

With respect to batteries and chargers, units will be considered for replacement if they are found to be in significant degraded condition or capacity based on assessments and diagnostic testing.

With respect to HPAs, ABCB replacements drive the timing of decommissioning of HPA systems. By 2027, the majority of 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.

2.2.3 ASSET COMPONENT INFORMATION – TRANSMISSION LINES

Transmission lines are used to interconnect system nodes, via network and radial circuits, to either direct transmission customers or to transformation points for distribution to retail customers. Major transmission line components include overhead conductors, underground cables, structures, foundations, insulators, and shieldwires.

2.2.3.1 OVERHEAD CONDUCTORS

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 comprised of 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 interconnected using splices and dead-end connectors, in-span and at dead-end structures respectively.

Asset Demographics

Hydro One's transmission overhead conductor fleet has an average age of 56 years with an ESL of 90, 70, and 100 years for ACSR, copper and aluminum type conductors respectively. ACSS conductors are relatively new and do not have an established ESL at this time. It is important to note that replacement and investment decisions are based on condition (not ESL), as further discussed below. Asset age is however useful as a screening criteria, triggering condition assessments on overhead conductors that are 50 years of age or older. Table 20 below summarizes the demographic profile of Hydro One's overhead conductor fleet.

Table 20 - Overhead Conductor Demographics[16]

Conductor Type	Circuit-km in Service	Average Age (Years)	ESL (Years)	Circuit-km Beyond ESL
ACSR	27,929	55	90	965
Copper	464	102	70	461
Aluminum	21	91	100	15
ACSS	138	28	N/A	N/A
Total	28,552	56		1,442

Asset Condition

In almost all cases, overhead conductors functionally deteriorate mechanically before they deteriorate electrically. For this reason, Hydro One assesses conductors for mechanical deterioration using the testing methods discussed in the Asset Maintenance and Inspection 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 across the entire conductor line section of the same vintage and type. Deterioration is different than conductor damage at a specific location due to localized trauma such as a tree fall, lightning strike or vandalism. In such cases, the resulting damage is confined to the immediate area, and can be remediated through localized repairs such as splicing.

The demand on a conductor's rated mechanical strength is not significant during normal operating conditions, under which actual tension 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. 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 during the next adverse weather event.

[16] EB-2019-0082 TSP 2.2 Table 17: quantity: 29,107 km, average age: 55 years, beyond ESL: 1,389 km.

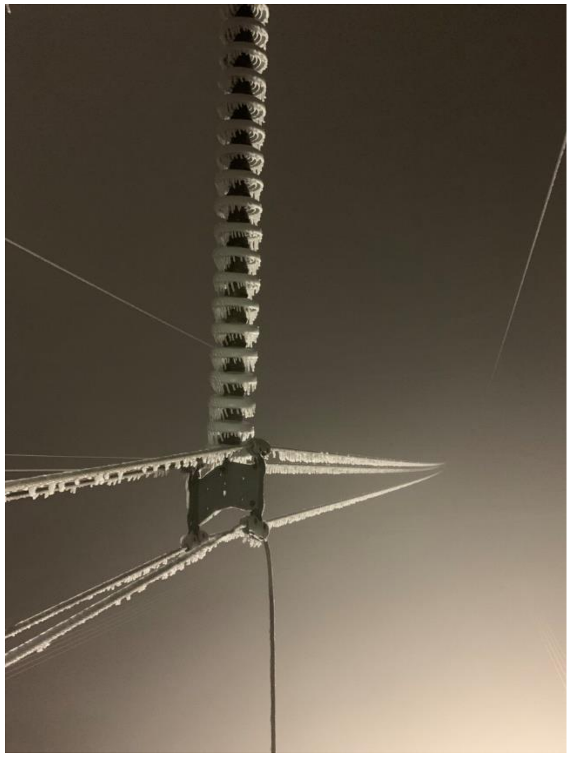

Figure 15: Broken conductor on ice accumulated 500 kV circuit B501M

Hydro One verifies the condition of its conductor fleet empirically by testing the bare conductor and connecting hardware. In many cases, deterioration is discovered on both the bare conductor and the 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. Hydro One's conductor testing practices are discussed below in the Asset Maintenance and Inspection Practices section.

Figure 16 demonstrates the condition distribution of Hydro One's transmission conductor fleet. Currently, 3,874 circuit-kms (14%) of Hydro One's conductor fleet is in poor condition, with another 12% exhibiting some deterioration, but not to an extent necessitating replacement. The current proportion of poor condition conductors represents an increase compared to the percentage presented in the EB-2019-0082 and EB-2016-0160 applications (13% and 9%, respectively). The subset of conductors in poor condition includes copper conductors that can no longer be repaired due to components being out of production.

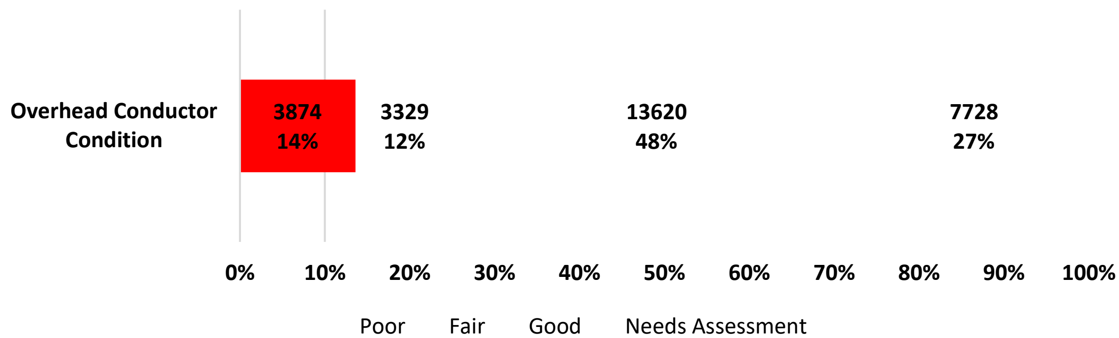

Figure 16: Distribution of Overhead Conductor Condition

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 performance becomes apparent. Given that reliability performance is a lagging indicator of the condition of the conductor fleet and that Hydro One's transmission system configuration reflects 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 severely endangers the people and property in proximity. A typical transmission line span is 300 metres at a rough 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 rare 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. For example, Figure 17 shows a conductor that dropped as a result of a polymer insulator failure in November 2018. The conductor made contact with and damaged two cars in the southbound lane. Fortunately, the conductor was not energized at the time of contact because the protection system operated as designed.

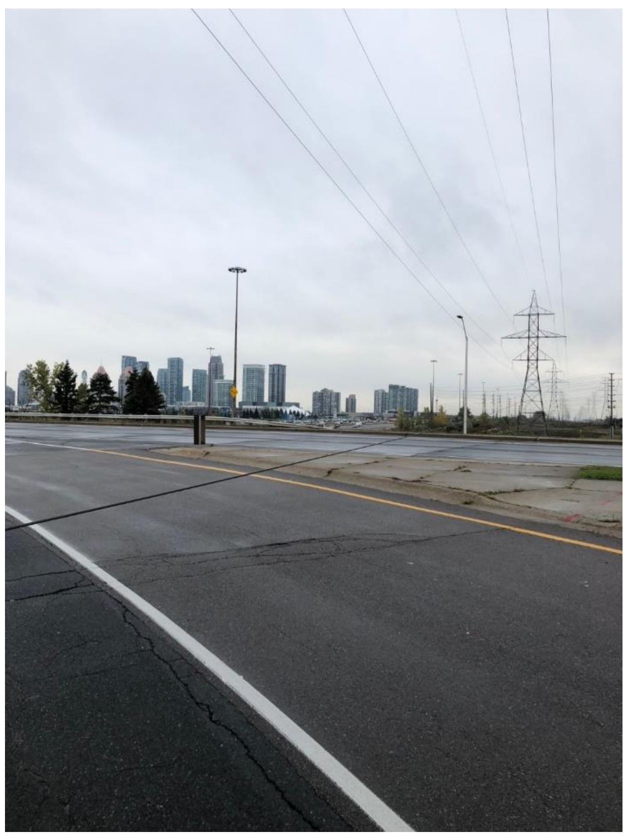

Figure 17: Dropped conductor on Circuit R17T over Highway 10.

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 capacity available), a failed circuit can cause the cascading outage of multiple circuits and interrupt numerous customers. Even where the conductor failure does not lead to an outage, it will impact system redundancy and the ability to obtain outages needed for planned maintenance and replacement work on other lines or stations equipment. For example, in 2020 a 500 kV circuit, N581M, experienced a fraying of its conductors and resulted in a forced outage. N581M is a critical element of the IESO controlled Southern Ontario System, and therefore this unplanned outage resulted in recalling numerous planned outages, delaying bus and switch work at Nanticoke TS, Middleport TS and work on circuits M20/21D. 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 made available to perform repairs.

As shown in Figure 18 and Figure 19, the frequency and duration of outages provide a current picture of how the conductors are performing, but does not drive investment decisions on conductor replacements. As a lagging indicator on aggregate, there is a delay between when conductor condition degrades and when this results in degradation in performance. Much 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 of the conductor. If Hydro One waits to address poor condition conductors until there is a noticeable impact on performance, the conductor fleet may have significantly degraded resulting in a large amount of conductor segments failing at the same time (for example during an extreme 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 can be seen in Figure 18. Outage duration, shown in Figure 19, is influenced by the location of the conductor outage and feasibility of the repair. Broken conductors in remote locations or conductors requiring adjacent outages for safe access have longer outage durations due to difficulty in access.

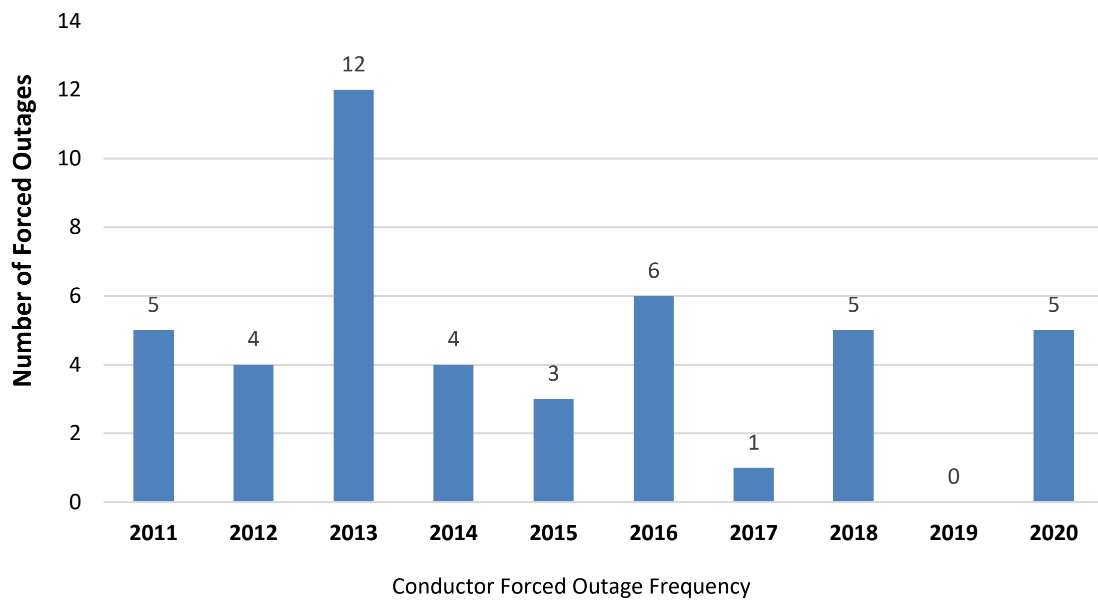

Figure 18: Overhead Conductor Forced Outage Frequency

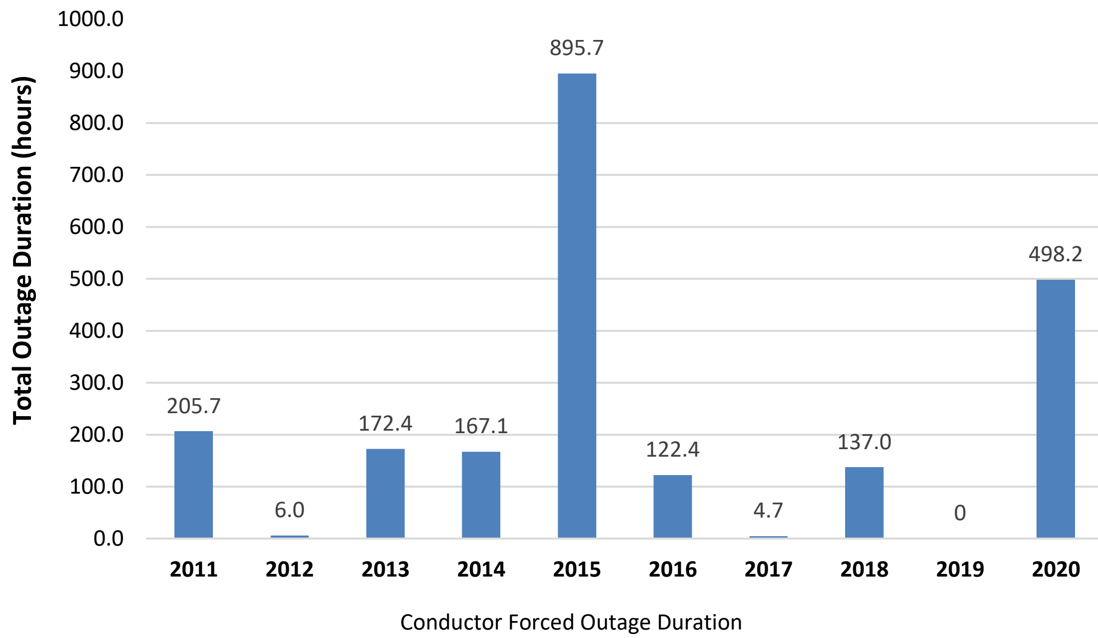

Figure 19: Overhead Conductor Forced Outage Duration

ASSET LIFE CYCLE

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

Asset Inspection & 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, orientation, local atmospheric contaminant levels, weather cycles, and stringing tension. For this reason, empirical testing is the only way to assess a conductor’s condition. Condition assessment begins when a conductor has been in service for 50 years, and not when a conductor reaches ESL.

Hydro One’s conductor fleet is regularly visually inspected through helicopter and foot 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 patrols cannot assess a conductor’s condition as deterioration is often 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, 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 been performing the majority of its ACSR conductor condition assessments through the Kinectrics LineVue tool. This tool is capable of traveling 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 efficient when compared to removing conductor samples for laboratory testing. LineVue also provides a visual 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 and laboratory testing a 5 meter conductor sample 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 provides an initial 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 whether condition-based replacement is required. Based on test results, the conductor will be scheduled for a follow-up assessment in 5 to 15 years depending on the determined level of deterioration, or planned for replacement if it is clearly identified as being in poor condition. Where signs of deterioration are found but poor condition is not clearly established based on test results, a more comprehensive assessment through a long conductor sample test is performed to ensure only poor condition conductors are targeted for replacement and to maximize the useful life of Hydro One's transmission conductors. In this regard, long sample tests can provide additional useful information (including the estimated remaining life of a conductor) where condition cannot be completely ascertained by LineVue and short sample testing. However, it is also much more expensive and can take months to complete. Accordingly, long samples are only used where necessary and feasible.

Asset Replacement and Refurbishment

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

Line refurbishment projects incorporate the refurbishment of all deteriorated components within the targeted line section, including structures, shieldwire, and insulators. Components that are in good condition are not refurbished or replaced during this time. Given that the conductor has the highest 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 likely that other line components have also deteriorated to poor condition and require replacement or refurbishment 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 reduces costs and time when compared to performing sustainment work piecemeal on an asset-by-asset basis.

As the population of poor condition conductors (currently at 14% or 3,874 km) continues to increase, so does the risk to public safety and reliability. Not addressing these increasing risks endangers the public and exposes Hydro One to a scenario where an extreme weather event could damage a significant amount of Hydro One's conductors, requiring a many resources to restore multiple circuits at once. It is prudent for Hydro One to proactively address the conductors in poor condition to avoid those risks to safety and reliability.

Hydro One is taking the opportunity of the line refurbishment work to reduce losses by using a larger conductor where appropriate (e.g. the D6V/D7V line refurbishment project (EB-2019-0165)). Future line refurbishment projects will use the Transmission Line Loss Guideline (TSP Section 2.3, Attachment 4) to determine the most economical option for reconductoring, factoring in the cost of losses.

2.2.3.2 UNDERGROUND CABLES

ASSET DESCRIPTION / PURPOSE

Underground transmission cable systems are used to transmit electrical power and typically connect portions of the overhead network and substations. They are commonly installed in areas where it is impossible or impractical to construct overhead transmission lines due to urban density, legal, environmental or safety reasons.

Underground cable systems consist of the main cables and ancillary equipment used to support cable operation. Cables are classified into the three following types:

- Low-Pressure Liquid-Filled (LPLF);

- High-Pressure Liquid-Filled (HPLF); and
- Extruded Cross-linked Polyethylene (XLPE).

LPLF and HPLF cables use paper and oil as the insulation medium while XLPE cables utilize an oil-free solid polyethylene material.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Asset Demographics

There are approximately 273 circuit km of in-service underground transmission line cables in the system operated at either 115 kV or 230 kV. The majority of Hydro One's underground transmission system (84%) is comprised of oil-filled cables (i.e. LPLF and HPLF), with the remainder (16%) being XLPE. The majority of cables are installed in densely populated urban areas, such as the Greater Toronto Area (GTA), Ottawa and Hamilton, and through Local Distribution Companies (LDC) service a significant portion of load in those regions. Therefore, failures resulting in loss of supply or redundancy will negatively affect a large number of downstream customers (i.e. LDC customers).

Hydro One's underground cable fleet has an average age of 37 years with an ESL of 70 years for LPLF and HPLF cables and 50 years for XLPE cables. A demographics summary of the cable population as of 2020 year-end is shown in Table 21. As discussed below, replacement investment decisions are made based on condition assessments, and not age or ESL.

Table 21 - Underground Cable Demographics

Cable Type	Circuit kms in Service	Average Age (Years)	ESL (Years)	Currently Beyond ESL
LPLF	56	53	70	0
HPLF	173	40	70	0
XLPE	44	7	50	0
Total	**273**	**37**	**-**	**0**

Asset Condition

Cable condition assessment is based on a variety of quantitative test factors applicable to the cable type. Condition assessment is described in more detail in the Testing & Maintenance Practices section below. Routine condition assessment and more intrusive diagnostic tests have shown that 97% of underground cables are in good or fair operating condition and therefore have a low risk profile. This is due to rigorous maintenance programs and operational practices (i.e. operating cables below their maximum thermal rating and insulating select 115 kV cables to 230 kV). Cables in poor condition (3% of the population) are either planned for replacement or are being closely monitored for continued degradation. Figure 20 illustrates the breakdown of cable condition.

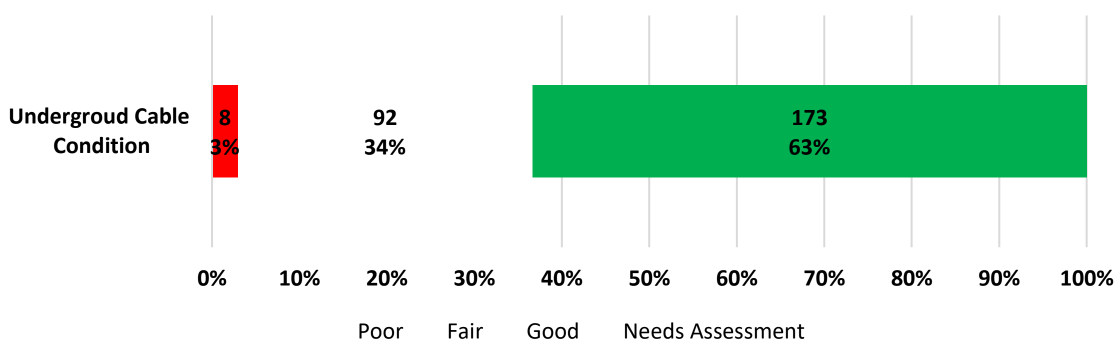

Figure 20: Cable Asset Condition Summary

As noted above, the majority of Hydro One's underground transmission system (84%) is comprised of oil-filled cables (i.e. LPLF and HPLF). There is an environmental risk in the event of a LPLF sheath/jacket or HPLF pipe rupture. Ruptures are not only caused by failed or degraded components but also by dig-ins from unauthorized excavation, which can result in the discharge of large volumes of oil into the surrounding environment requiring clean-up and remediation.

Asset Performance

Cable outages are infrequent and normally do not result in delivery point interruptions, given that most delivery points are connected to two circuits for redundancy and circuits are in a network configuration. However, a single supply may not be able to meet the customer's full demand. A forced outage resulting from an underground cable failure can be lengthy in duration, with an average repair time of approximately 35 days. For example, locating and repairing cable leaks requires substantial excavation and is a time-consuming process that can result in outages lasting weeks to months.

The frequency and duration of underground cable caused circuit outages from 2011 through 2020 are summarized in Figure 21 and Figure 22 below. The majority of these outages were caused by condition related cable system component failures. Due to the relatively small number of outages, it is not possible to infer a statistically significant performance trend.

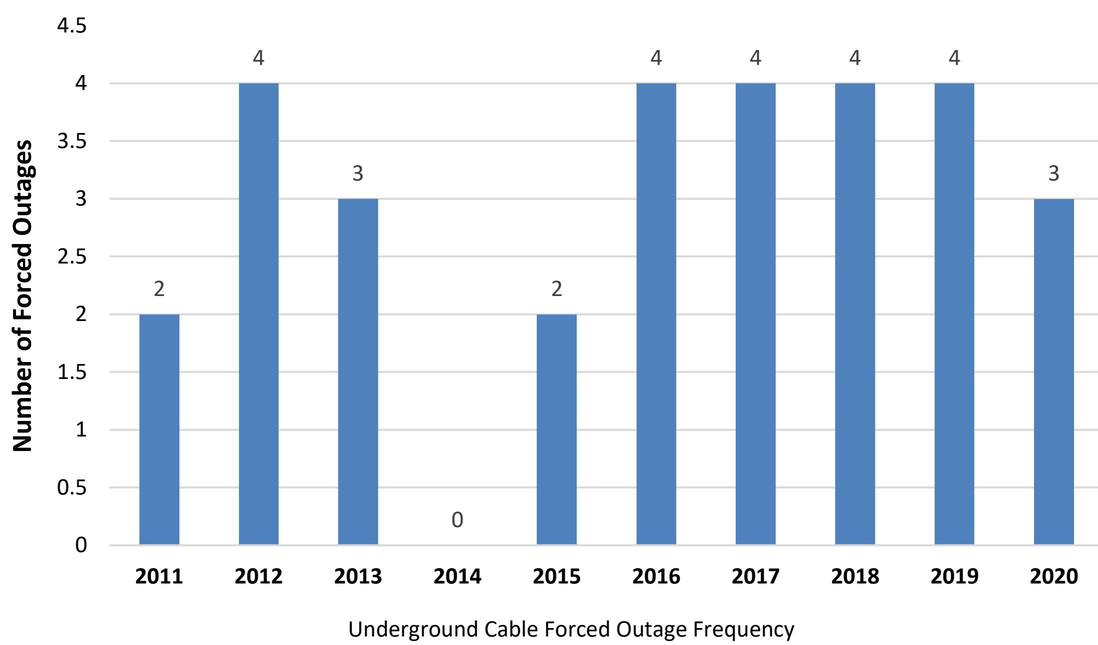

Figure 21: Cable Outage Frequency

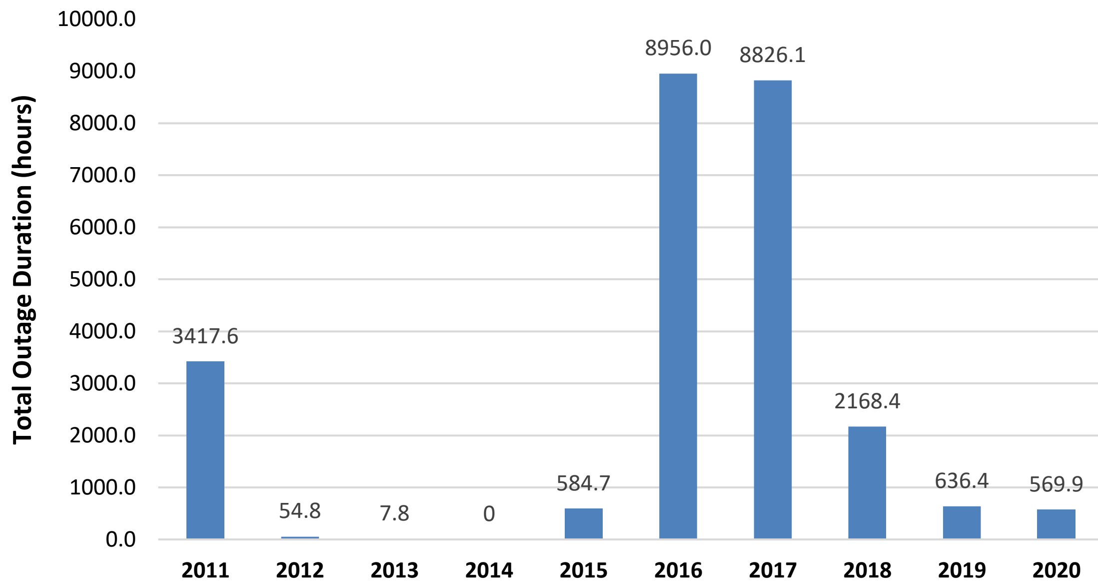

Figure 22: Cable Outage Duration

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

ASSET LIFE CYCLE

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

Asset Testing & Maintenance Practices

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

i. preventive maintenance, comprising of condition assessment and testing activities;
ii. corrective maintenance, activities undertaken to investigate and repair equipment deficiencies; and
iii. cable locates.

These programs are discussed in detail in Exhibit E-02-02. As a key aspect of Hydro One's cable asset strategy to maximize service life, cable testing and maintenance programs reduce the risk of cable equipment failure, which as discussed above can seriously impact the environment (oil leaks) and reliability (loss of service and redundancy).

The majority of Hydro One's cable assets are in good condition. This is due to rigorous maintenance programs and operational practices. Rigorous historical maintenance programs must be continued to prevent increased failures, associated outages and oil leaks in the long-term.

The fundamental objective of Hydro One's cable sustainment strategy is to maximize service life in order to minimize capital replacement expenditures. This is primarily done through preventive maintenance (condition assessment and testing activities) and corrective maintenance (repair) programs. Hydro One will continue to perform rigorous preventive maintenance and critical planned and demand repairs. Non-critical planned corrective maintenance and supplemental non-routine tests to obtain detailed condition data will be prioritized and/or deferred. While this deferral may result in an increased number of demand failure repairs, this risk will be mitigated through the prioritization of planned repairs.

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 risks due to oil and obsolescence risks associated with LPLF and HPLF cables. XLPE are also currently the most widely used cable technology. LPLF and HPLF cables may be considered for special applications such as repairs and the relocation of short circuit lengths. There is an industry shift away from the use of LPLF and HPLF to XLPE cable systems. As such, manufacturers have been reducing production and support for oil-filled cables. To mitigate this obsolescence risk, Hydro One manages a spare inventory of LPLF and HPLF cables and ancillary equipment. In addition, Hydro One will continue to integrate distributed temperature sensing (DTS) systems for new and replacement cable installations where needed and feasible. Cable operating current can change over time due to external factors leading to cable overheating and damage thereby reducing its useful life. These systems enable real-time temperature monitoring and thermal optimization to manage current and maximize service life.

2.2.3.3 STRUCTURES & FOUNDATIONS

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 serve the same purpose as steel structures. The majority of the wood pole structure population is 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.

Foundations

Foundations support and anchor transmission structures to the ground and enable the structures to withstand the weight of the structure itself, 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.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

Asset Demographics

Steel Structures

Hydro One has approximately 49,200 lattice steel structures and approximately 1,750 steel poles supporting 115kV to 500kV transmission lines. Current steel structures have an average age of 63 years and an ESL of 80 years if they are not re-coated. However, if re-coated, the steel structures' service life can extend beyond the ESL. The demographics of the steel structure population are outlined in Table 22 below.

Table 22 - Steel Structure Demographics

	Quantity	Average Age	ESL (Years)	Currently Beyond ESL
Steel Towers in Light Corrosion Zones (C2 and C3)	10,400	61	80	2,600
Steel Towers In High to Very High Corrosion Zones (C4 and C5)	38,800	63	80	8,800
Steel Poles	1,750	37	80	85
Total	50,950	61	80	11,485

Wood Pole Structures

Hydro One has approximately 40,000 wood pole structures in its transmission system. The average age of the wood pole fleet is 37 years and 12,400 of the wood poles are beyond their ESL of 50 years.[17] The demographics of the wood pole population are outlined in Table 23.

Table 23 - Wood Pole Structure Demographics

Wood Structure	Quantity	Average Age	ESL (Years)	Beyond ESL currently
Total	40,000	37	50	12,400

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. The demographics of the steel lattice structure foundations are outlined in Table 24:

Table 24 - Foundation Demographics

Foundation Type	Quantity	Average Age (Years)	ESL (Years)	Beyond ESL
Cast-in Concrete Footings	16,700	37	100+	0
Steel Grillage Footings	32,500	76	80	11,300
Total	49,200	-	-	11,300

[17] 42,000 wood poles stated in in prior rate application EB-2019-0082 TSP-02-02 Table 20 included Hydro One managed but externally owned wood poles. These wood poles have been excluded.

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 8 to 10. 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 13,500 of the steel structures in C4 and C5 zones are in fair or poor condition, reflecting that the steel structure has corrosion on the HDG and on the bare steel layer. These structures 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 2,000 towers have either previously been fixed or will be as part of refurbishment projects, and about 5,000 towers are still in need of repair.

Wood Pole Structures

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

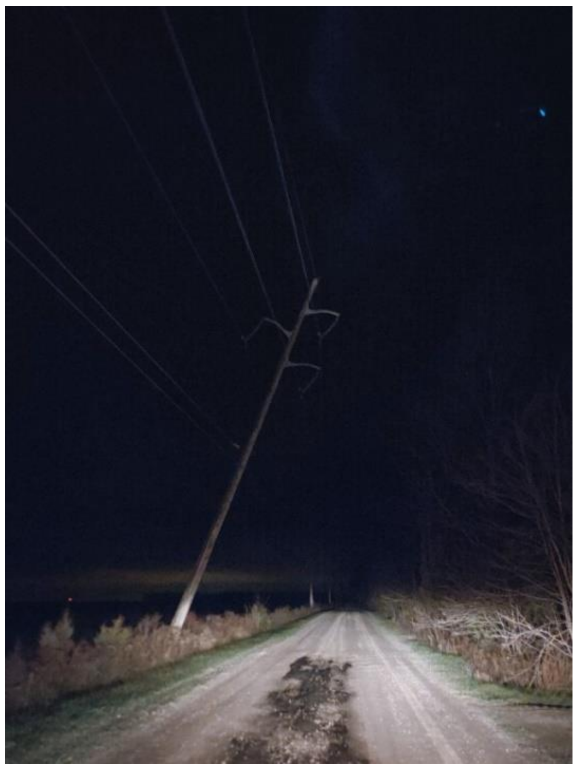

Figure 23: Failed Wood Pole on Circuit S2N

Figure 24: Failed Wood Pole on Circuit P4S

Based on available wood pole condition data, 4,693 wood pole structures, which corresponds to approximately 12% of Hydro One's wood pole population are in poor condition, as illustrated in Figure 25. These poor condition poles typically exhibit internal or external rotting, woodpecker damage, mechanical damage or insect damage. Approximately 29% (11,482 structures) of the wood pole population needs to be assessed to determine its condition, while about 60% (23,866 structures) of the population is either in good condition or not eligible for assessment (i.e. younger than 25 years).

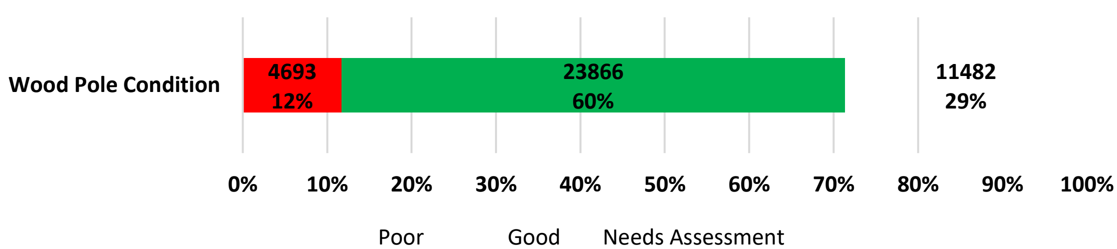

Figure 25: Wood Pole Fleet Condition Status

Foundations

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 3,300 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.

Asset Performance

Steel Structures

Forced outages for steel structures represent the number of outage caused by a steel structure failure such as complete tower collapse or a broken (or bent) tower member. It excludes forced outages caused by catastrophic damage (i.e. caused by transmission lines being struck by tornado, aircraft, truck, etc.). Figure 26 and Figure 27 below illustrate the frequency and duration of forced outages due to steel structure failures in the past 10 years. Based on the forced outage information below, the average restoration time for failed steel structure is 9 days. 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 economic savings as opposed to reliability and safety risk mitigation.

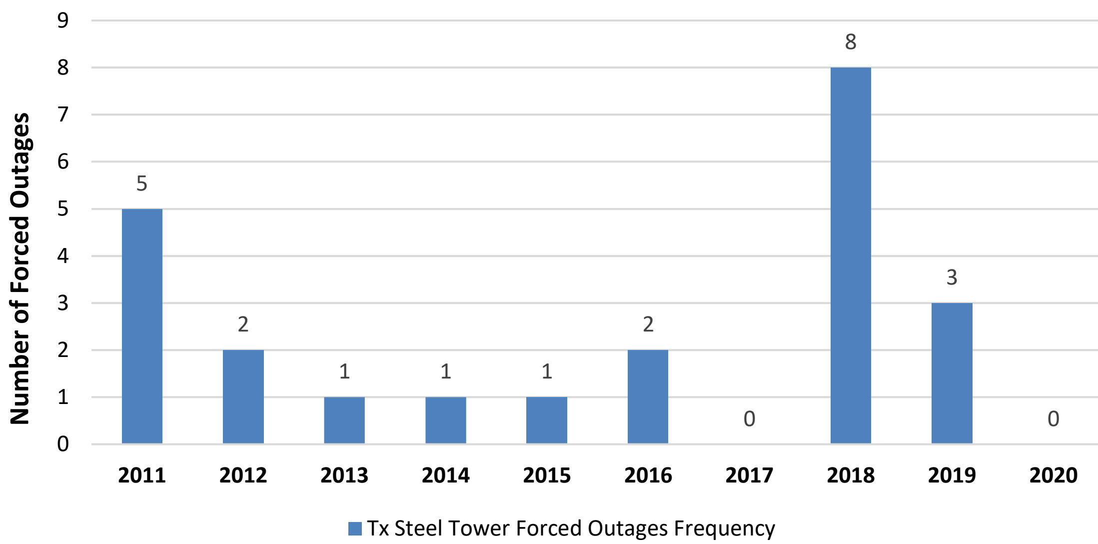

Figure 26: Forced Outages Frequency Due to Steel Structure Failures

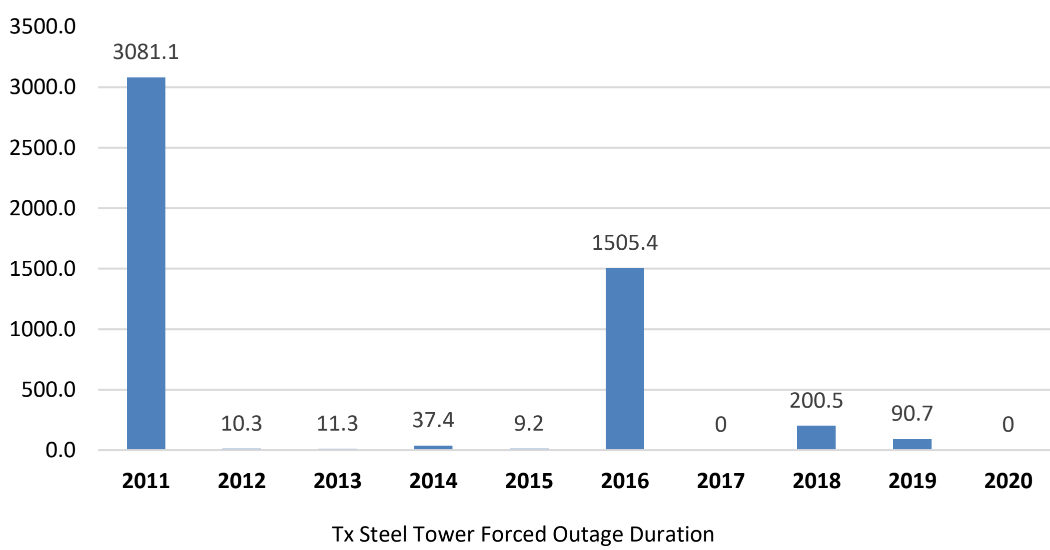

Figure 27: Forced Outage Duration Due to Steel Structure Failures

<u>Wood Pole Structures</u>

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.

As shown in Figure 28, the number of forced outages due to wood pole structure failures has increased over the past ten years. Wood pole failure is the result of a combination of factors, such as pole condition, weather condition, physical loading, and the local environment, so the increasing trend is not necessarily indicative of worsening pole condition. Wood poles are a natural product that despite treatment, have some quality inconsistencies in each pole, which can result in an unpredictable failure under certain conditions. Based on the forced outage information below, the average restoration time for failed wood pole structure is around 2 days. Note that the frequency and duration of forced outages do not drive wood pole replacement investment decisions.

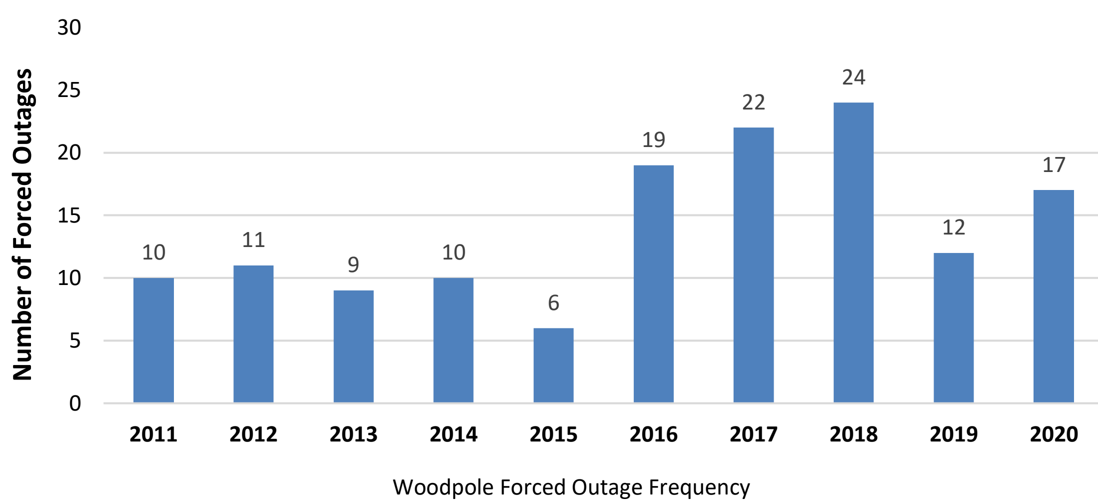

Figure 28: Forced Outage Frequency Due to Wood Pole Failures

The forced outage duration is shown in Figure 29. Hydro One will continue to monitor the condition of its wood pole feet and implement the necessary steps to mitigate any emerging trends.

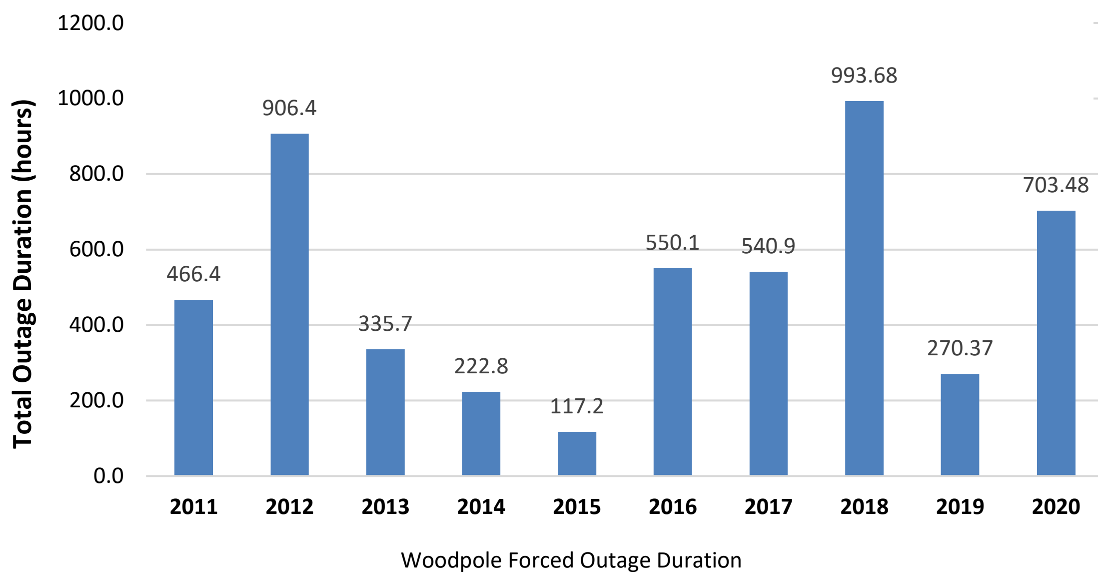

Figure 29: Forced Outage Duration due to Wood Pole Failures

ASSET LIFE CYCLE

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 uses a condition-based asset management strategy to sustain its fleet. Age is used as a criterion for determining assessment candidates only.

Foundations

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

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[18] that have been developed in accordance with standards set by the Society for Protective Coatings. Based on patrol results, a detailed engineering corrosion assessment may be undertaken for severe cases to measure metal loss and assess bolts and fittings. The assessment also 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. Wood poles are inspected through the overhead lines patrol and condition assessment program based on structure age, known deficiencies, past failures and field recommendations. 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 Assess, Clean and Coat Program and line refurbishment projects. There are very few cases where concrete

[18] 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.

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.

Asset Replacement and Refurbishment

Steel Structures

If steel structures are not re-coated 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 is composed of zone C4 and C5. By recoating structures that experienced less than 10% steel loss, the service life of the structure can be extended, thereby minimizing lifecycle cost. The main driver for the tower coating program is based on economic savings as opposed to reliability and safety risk mitigation. Based on prior analysis, net present value calculations show significant savings from tower coating versus tower replacement. In regards to the 230kV 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 to the impacted structure types since 2019 and will continue such repairs until all affected structures are refurbished.

Wood Poles

Hydro One will continue to proactively replace poor condition wood structures identified from patrols and condition assessment. 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 assessing, cleaning or coating based on factors such as circuit voltage, criticality of the circuit and customer impact. Based on the corrosion severity of steel structures identified from the assess/clean/coat program, the foundations are either cleaned and coated to re-establish the layer of protection or scheduled for future repairs or replacements. The Foundation Repair Program is used to complete repairs or replacements of foundations identified through the previous program.

2.2.3.4 INSULATORS

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 30 below. Insulator classifications are summarized in Table 25 below.

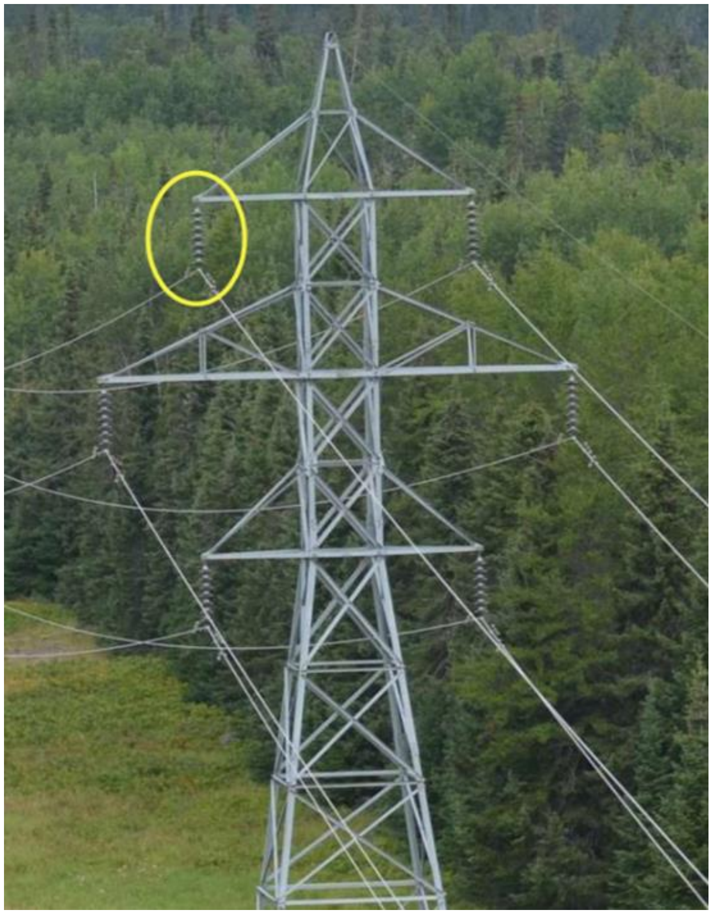

Figure 30: Transmission Line Insulator String

Table 25 - 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. Their material properties entail the following benefits: • Lighter-weight (making them easier to install); • Vandalism resistance (less susceptible to mechanical damage); and • Better contamination performance (less likely to flashover in contaminated environments).

Asset Demographics, Condition & Other Factors

Asset Demographics

There are approximately 437,000 insulator strings on approximately 119,500 circuit structures in Hydro One's overhead transmission network. The insulator demographics by material type are shown in Table 26 below.

Table 26 - Insulator Demographics

Insulator Type	Quantity (Circuit Structures)
Porcelain	71,675
Glass	35,838
Polymer	11,946
Total	119,459

Demographics are not a driving factor for the replacement of porcelain or glass insulators since 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 approaching their ESL and will need to be evaluated for replacement. 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.

Many insulators are used on structures in public areas or in areas that can be easily accessed by the public. In the event of a mechanical failure and conductor drop, these locations pose a high risk to the public, and therefore need to be prioritized as part of a proactive plan, as further discussed below.

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 1960 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 31. 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 31: Porcelain Insulator Unit Affected by 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 urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed in publicly accessible (critical) structures where public safety is at risk. A sample of pre-1965 insulators was also assessed by EPRI, which showed satisfactory results for 1950's models but again poor results for insulators made in 1960 and beyond. Due to this outcome, and recent 1962 and 1963 insulator failures on the Hydro One system, and because EPRI was unable to confirm the accuracy of the 1965 cut-off date, Hydro One has decided to extend the targeted range to 1960-1982 in order to remove all defective COB and CP insulators from its transmission system.

Phase two of the testing was performed on 591 insulators in 2017 to supplement Phase one findings and to provide data on the rate of deterioration 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.

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 37,000 circuit structures with defective porcelain insulators and roughly 17,000 of those were on structures in publicly accessible (critical) locations, including roads, waterways, urban areas, golf courses, educational and health care facilities. To date, approximately 16,500 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 2020 year-end is shown in Figure 32 below.

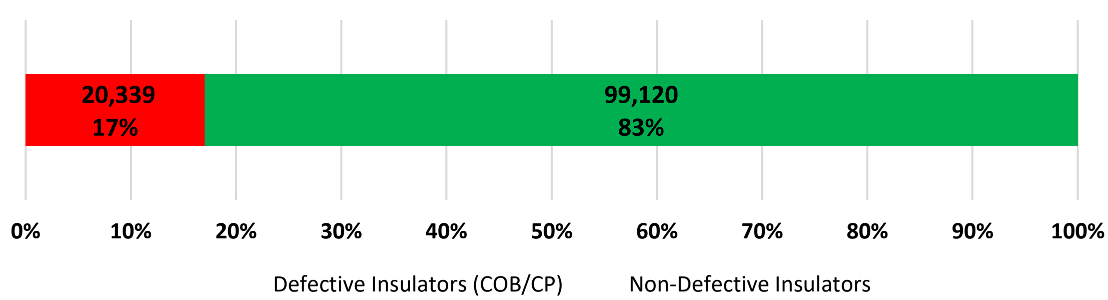

Figure 32: Insulator Fleet Condition Status

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. A more recent example of a major insulator failure occurred in 2019 on 500kV circuit D501P in Timmins, Ontario. The failed unit was a 1962 porcelain insulator and in this case the conductor did not drop as the idler string held on until crews arrived. Photos of these failures are provided in Figure 33 through Figure 36 below.

Figure 33: V76R Insulator Failure

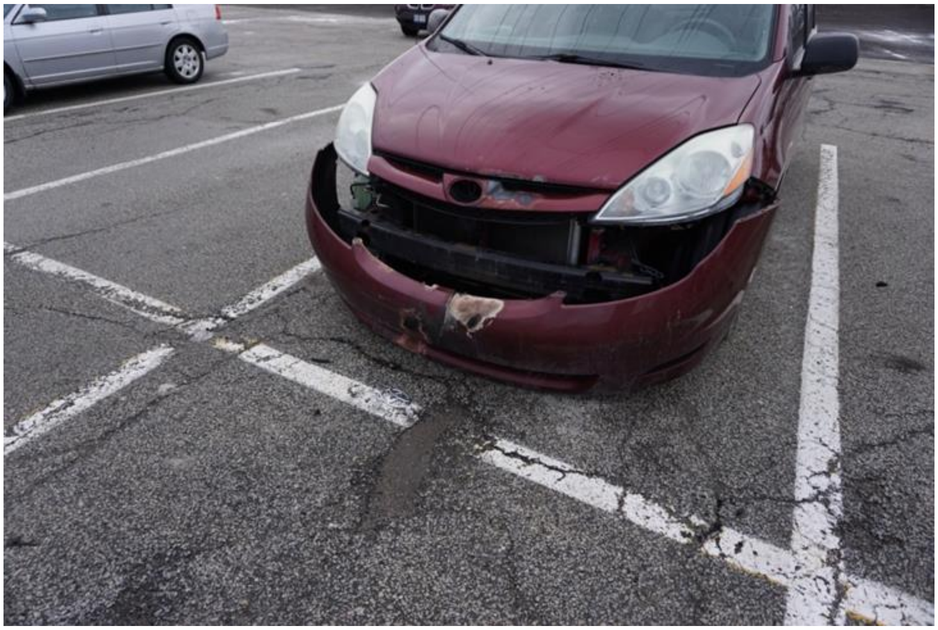

Figure 34: V76R Insulator Failure

Figure 35: V76R Insulator Failure

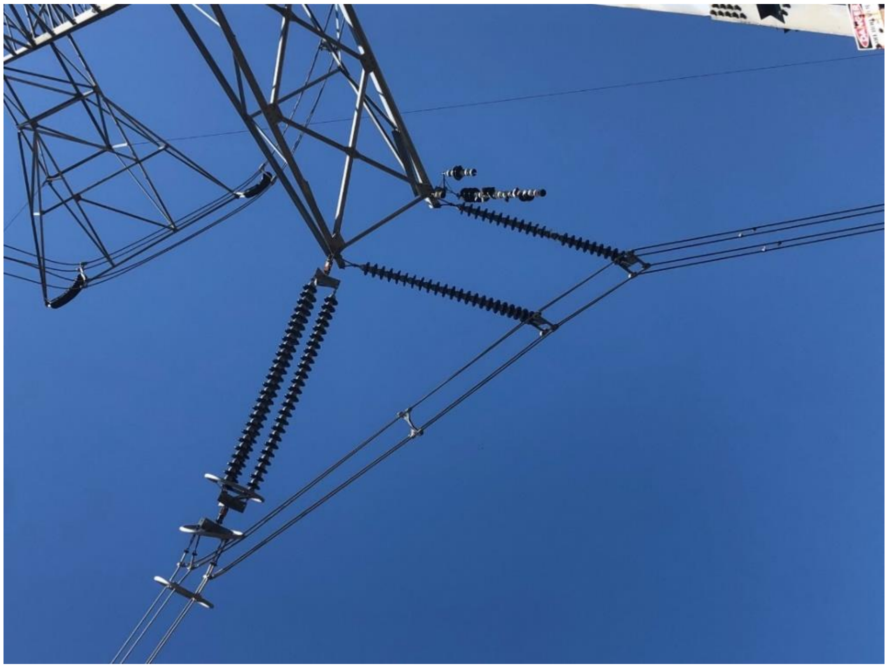

Figure 36: D501P Insulator Failure

Since portions of Hydro One's polymer insulator population are 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 the service life ranging from 13 to 26 years. The following three insulator configurations form the scope of the EPRI study:

- 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 should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. Considering the study results, Hydro One is exploring 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 underscored by two failures which occurred in October and November 2016. Both failures resulted from 230 kV polymer suspension insulators on C28C failing mechanically, resulting in a conductor drop, as shown in the photos in Figure 37 through Figure 39. The dropped conductor did not contact the ground but was held in the structure window. Hydro One began replacing polymer insulators in 230 kV dead-end configuration in 2016, and Hydro One is currently in the process of identifying the number of impacted polymer insulators and will explore incorporating them into the insulator replacement program once more information is available.

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2 **Figure 37: Failed Polymer Insulator**

3

4 

5 **Figure 38: Failed Polymer Insulator**

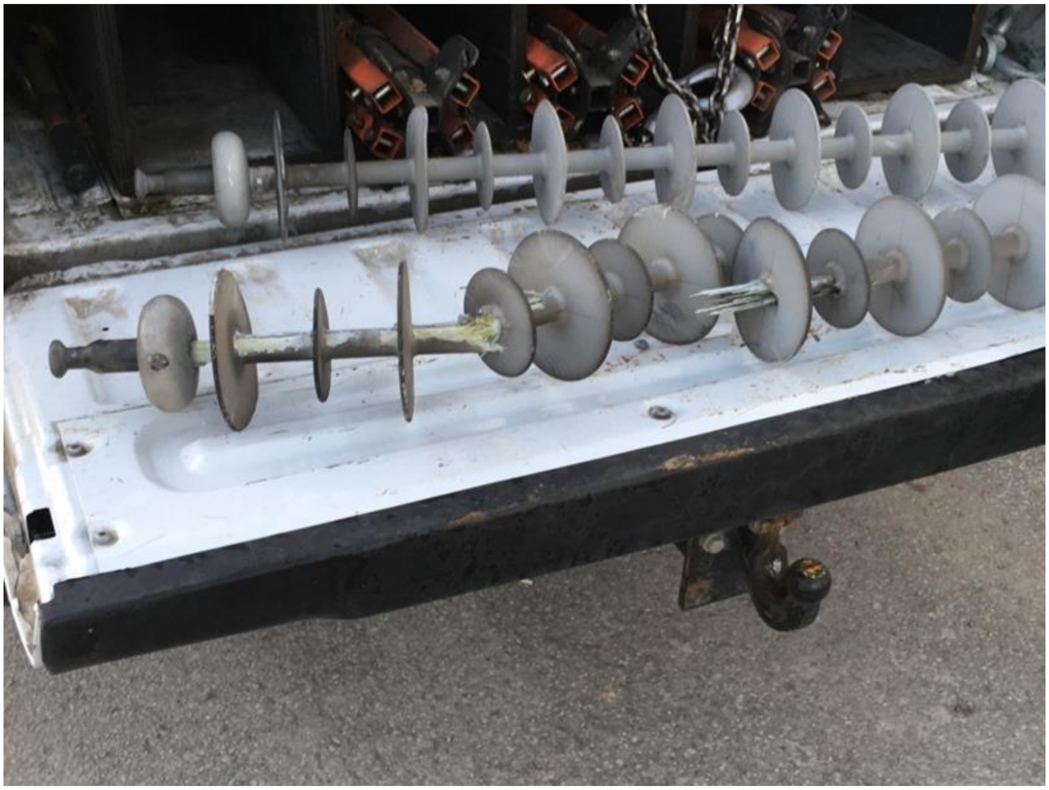

Figure 39: Failed Polymer Insulator

Asset Performance

Figure 40 and Figure 41 illustrate the frequency and duration of insulator-caused circuit outages between 2011 and 2020, which have remained relatively stable. However, the number of failures is expected to rise due to the degradation of the known defective COB and CP porcelain insulators. Figure 42 illustrates the number of COB and CP failures over the past 10 years, which shows a significant upward trend.

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.

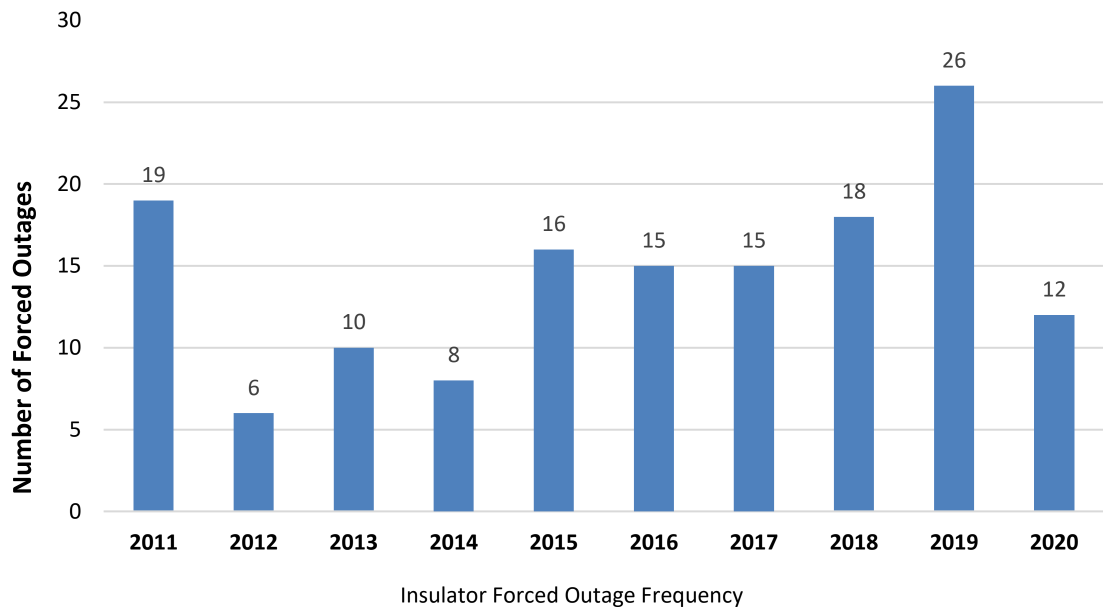

Figure 40: Insulator Outage Frequency

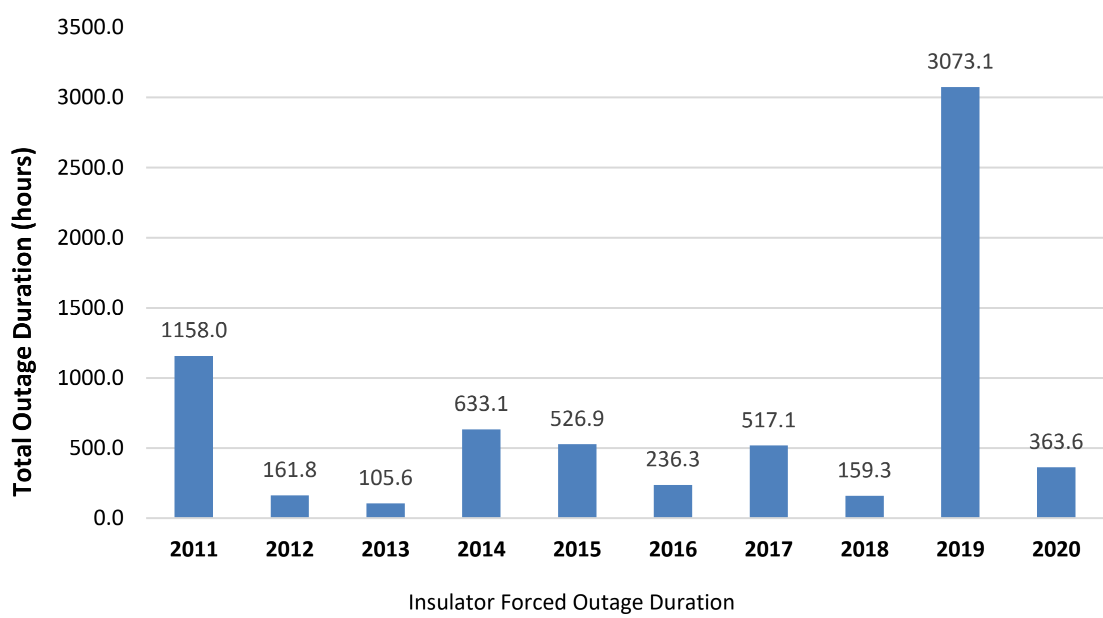

Figure 41: Insulator Outage Duration

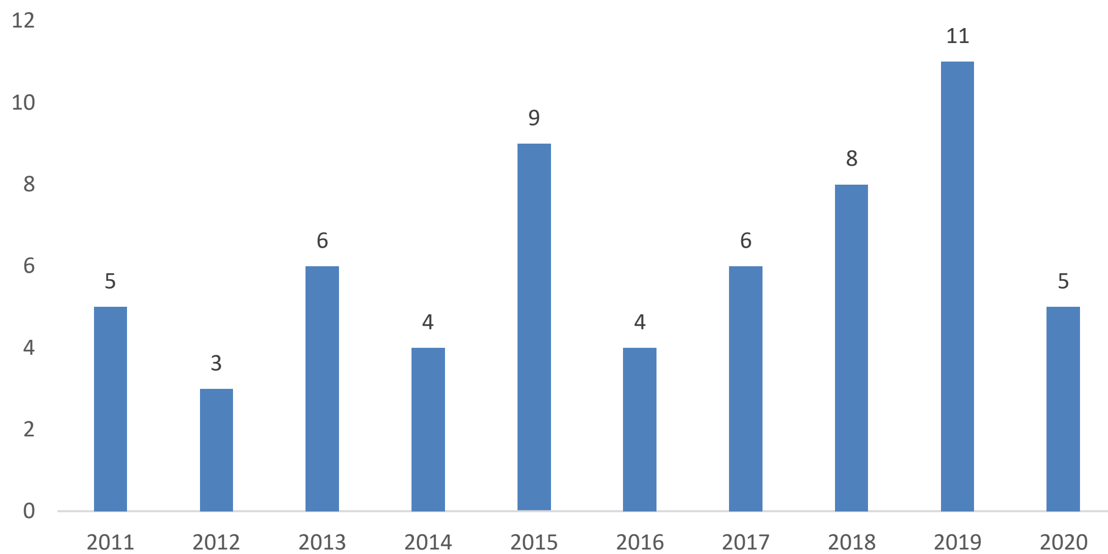

Figure 42: Number of COB/CP Insulator Failures per year

ASSET LIFE CYCLE

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

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 the replacement. Condition assessment methods include visual inspections from the air or ground and are bundled with line and structure inspections and patrols.

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 and is prioritizing those that pose a substantial public safety risk, as further discussed in TSP Section 2.11, T-SR-08. As part of this replacement program, insulators in publicly accessible (critical) areas are planned for replacement by 2023, with the remaining defective insulators planned for replacement by 2028.

Polymer Insulator Replacement

Polymer insulators in 230 kV 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 230 kV dead-ends, 230kV polymer insulators without a corona ring, or with corona rings that are 4 inches or smaller, will also be added to the insulator replacement program at a future date. Hydro One is currently in the process of identifying the number of impacted polymer insulators and will incorporate their replacements into the existing insulator replacement program. The issues associated with polymer insulators are further discussed in TSP Section 2.11, T-SR-08.

2.2.3.5 RIGHTS OF WAY

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 81,500 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.

ASSET DEMOGRAPHICS, CONDITION & OTHER FACTORS

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 4, 6 or 8 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 6-year cycle in the Central, East and Southern zones and on an 8-year cycle in the North. Some corridors in Eastern and Southern Ontario are maintained on a 4-year cycle due to faster vegetation growth rates. Maintenance is completed in Northern Ontario on a longer cycle due to the 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 27.

Table 27 - Summary of Rights of Way Demographics

Zone	4 Year Cycle	6 Year Cycle	8 Year Cycle	Total Hectares (Zone)
Central	0	14,666	0	14,666
East	530	17,050	0	17,580
North	0	193	30,962	31,155
South	892	17,228	0	18,120
Total Hectares (Cycle)	1,422	49,137	30,962	**81,521**

Asset Condition

If left unmanaged, 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 11% (i.e. 9,110 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 43 illustrates the breakdown of ROWs in poor, fair, and good condition.

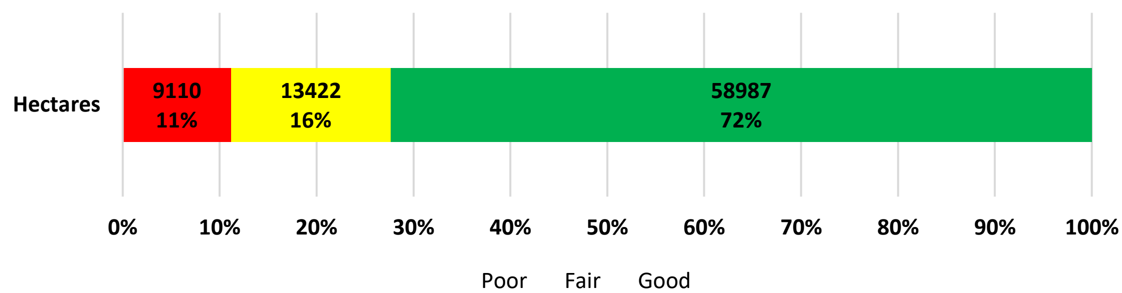

Figure 43: Condition of Hydro One ROW

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'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 44 provides the frequency of all vegetation caused forced outages on Hydro One's network (both the NERC reportable and non-reportable outages).[19] The duration of these outages is displayed in Figure 45.

[19] 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.

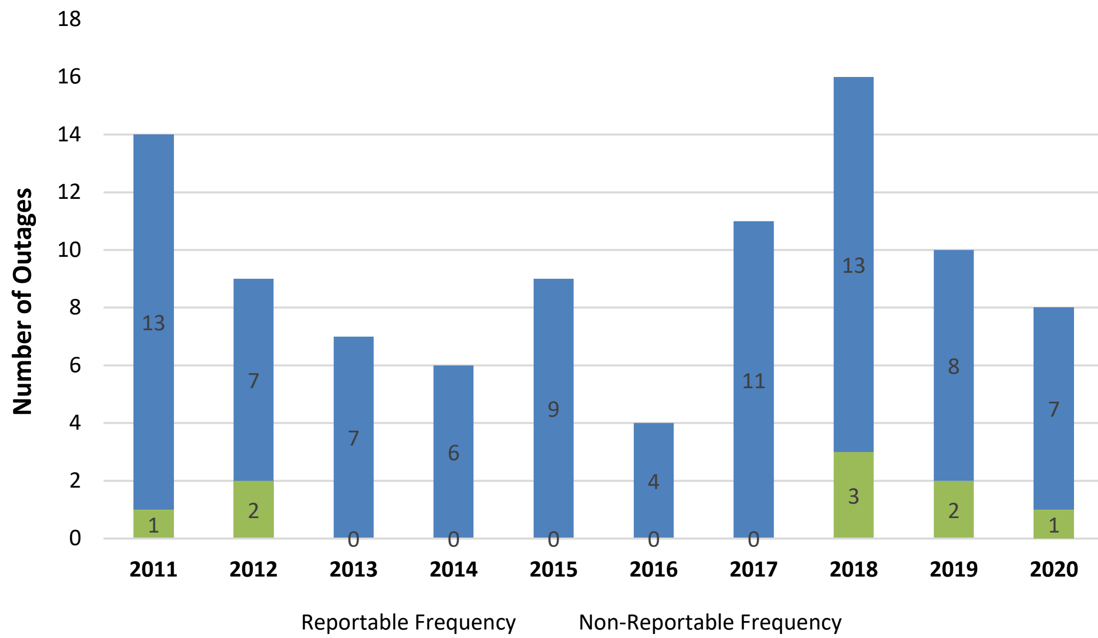

Figure 44: Hydro One's Vegetation Related Outage Frequency

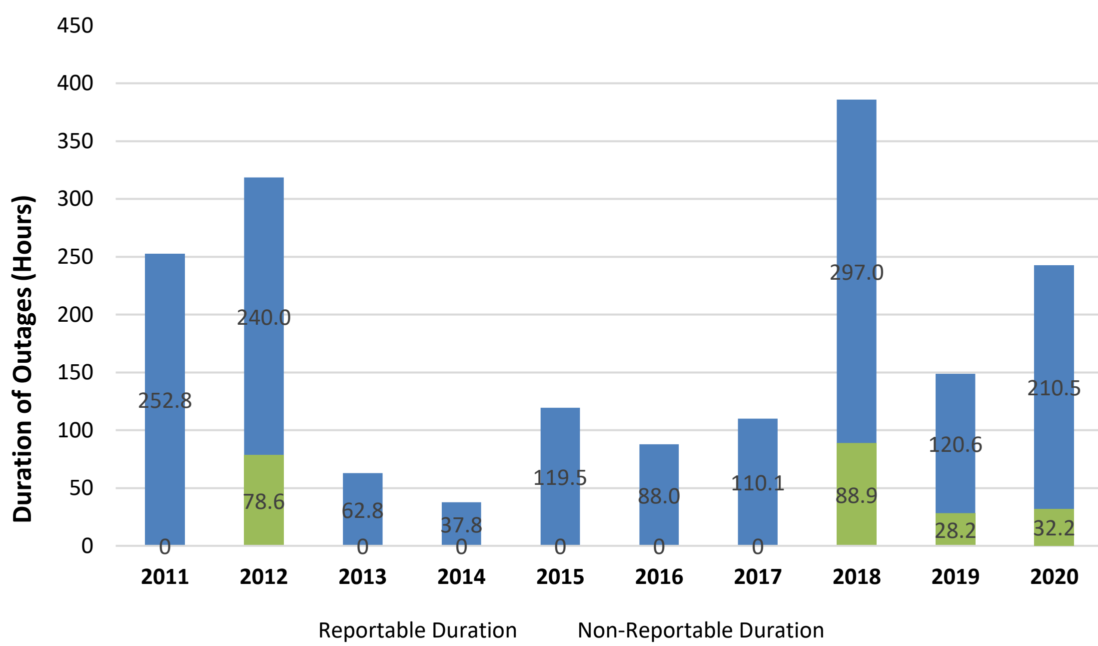

Figure 45: Duration of Vegetation Related Outages on Hydro One Circuits

ASSET LIFE CYCLE

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 work has included a large urban component in the last few years (2018 to 2020) due to the cyclical nature of the work program. 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 past targeted cycles, vegetation growth continues to increase along Hydro One's transmission corridors. The current backlog of 9,110 ha in poor condition ROWs (i.e., behind their vegetation maintenance cycle) needs to be addressed in order to maintain system reliability and control costs associated with having to maintain an overgrown ROW. Postponement of vegetation management work increases reliability risks and results in a vegetation backlog that is more difficult and costly to clear in the future. Hydro One prioritizes vegetation maintenance on NERC FAC-003 regulated and critical ROWs in order to manage this backlog.

Hydro One Distribution follows the Optimal Cycle Protocol (as discussed in Exhibit E-03-02), which stemmed from a Distribution-specific vegetation management study and differs from the Transmission Vegetation Management Program. Due to differences in design requirements and vegetation clearance distances, distribution vegetation management cycle times cannot be compared to transmission. The targeted line clearing and brush control cycle lengths for Hydro

One's Transmission Vegetation Management Program have shown to successfully maintain system reliability and have not changed.

Having said that, Hydro One Transmission is exploring opportunities for increased flexibility and targeted maintenance in vegetation management. To further optimize the program, new technological solutions, such as Light Detection and Ranging (LiDAR), are being considered to help identify any potential vegetation encroachments upon Hydro One's transmission lines. LiDAR is a remote sensing technology that is used by utilities to obtain accurate geospatial images and measurements of circuits and surrounding vegetation. A large scale pilot project to collect LiDAR data and detailed images of Hydro One's transmission line assets was planned for 2021 and is currently ongoing. The results of this pilot project will be used to evaluate the capabilities of potential vendors, benefits and concerns arising from the technology, and the value it offers the Transmission Lines and Vegetation Management work programs.

Inspection & Maintenance Practices

Specifically, maintenance of Hydro One'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. **Condition Patrol**: mid-cycle working inspections which identify and mitigate any vegetation which requires maintenance prior to the next scheduled line clearing or brush control activity. ROW condition information is used to prioritize future maintenance activities.
4. **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.

5. **Annual Vegetation Patrol**: In accordance with NERC standard FAC-003, Hydro One is required to annually inspect all of its circuits that are 230 kV or higher. Consequently, visual inspections by helicopter or ground are performed on all NERC applicable circuits not receiving Line Clearing or Condition Patrol maintenance in the current calendar year.
6. **Demand Maintenance**: addresses vegetation management issues that cannot wait until the next scheduled line clearing or brush control activity.
7. **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.

2.2.3.6 SHIELDWIRE

ASSET DESCRIPTION / PURPOSE

Shieldwire is used to provide lightning protection and grounding continuity to transmission lines. There are approximately 34,800 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 28.

Table 28 - Summary of Shieldwire by Type

Shieldwire Type	Vintage	Description
Galvanized Steel	Installed until approx. 1990	Galvanized Steel is the most common type of shieldwire currently installed 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, also known as Alumoweld	Installed since approx. 1980s	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 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, also known as 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.

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

Asset Demographics

The average age of Hydro One's shieldwire fleet is approximately 45 years. Approximately 61% of Hydro One's shieldwire fleet is galvanized steel and 30% is Alumoweld. The demographic details of Hydro One's shieldwire fleet as of year-end 2020 are shown in Table 29. Due to historic construction and demographic patterns, Hydro One is now entering 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). However, it is important to note that shieldwire replacements are based on condition, not age.

Table 29 - Summary of Shieldwire Demographics

Shieldwire Type	In- Service Length (km)	Average Age	ESL (Years)	Currently Beyond ESL (km)
Galvanized Steel	21,312	57	50	11,135
Alumoweld	10,596	28	60	33
OPGW	2,077	23	40	234
ACSR	606	36	90	4
Copperweld	176	69	N/A*	176
Total	34,767	45	-	11,581

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

Asset Condition

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

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 shieldwire fleet is summarized in Figure 46. The "needs assessment" category refers to shieldwires which have reached the age threshold for condition assessment and will be assessed in the future under Hydro One's shieldwire condition assessment program.

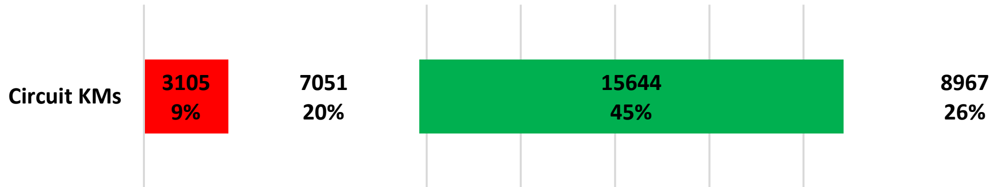

Figure 46: Condition Risk of Shieldwire Assets

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 47 and Figure 48 provide a summary of all shieldwire caused forced outages. 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 to historical levels in 2020 as seen in Figure 47, while outage duration has increased notably in the past 5 years as seen in Figure 48.

The higher frequency in 2018 is due to an ice storm in April, which resulted in 4 registered outage events due to broken shieldwire. Of these 4 events, only one resulted in a sustained duration of almost 2 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 8 registered outage events due to broken shieldwire. Of these 8 events, the longest one lasted about 6 hours, while the others were under 10 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.

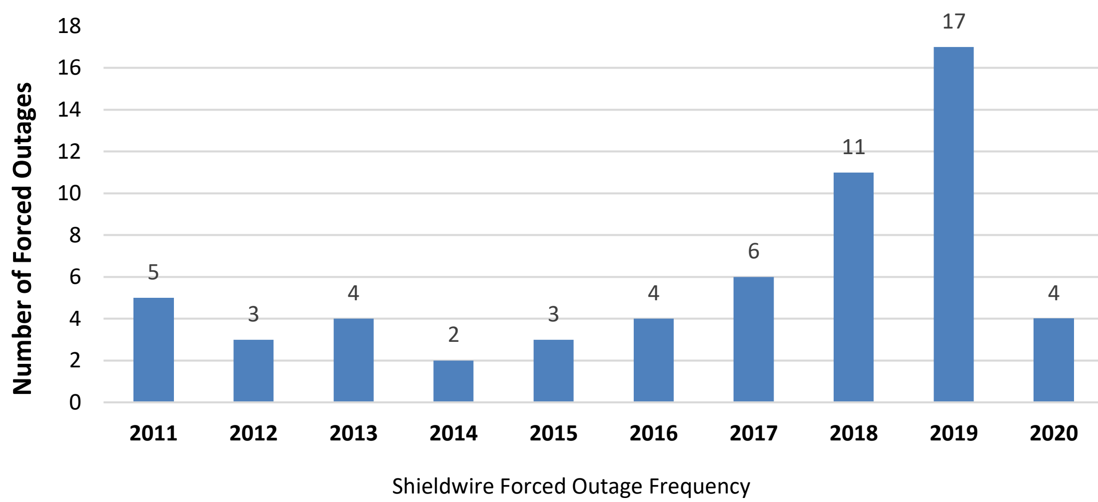

Figure 47: Frequency of Shieldwire Related Outages

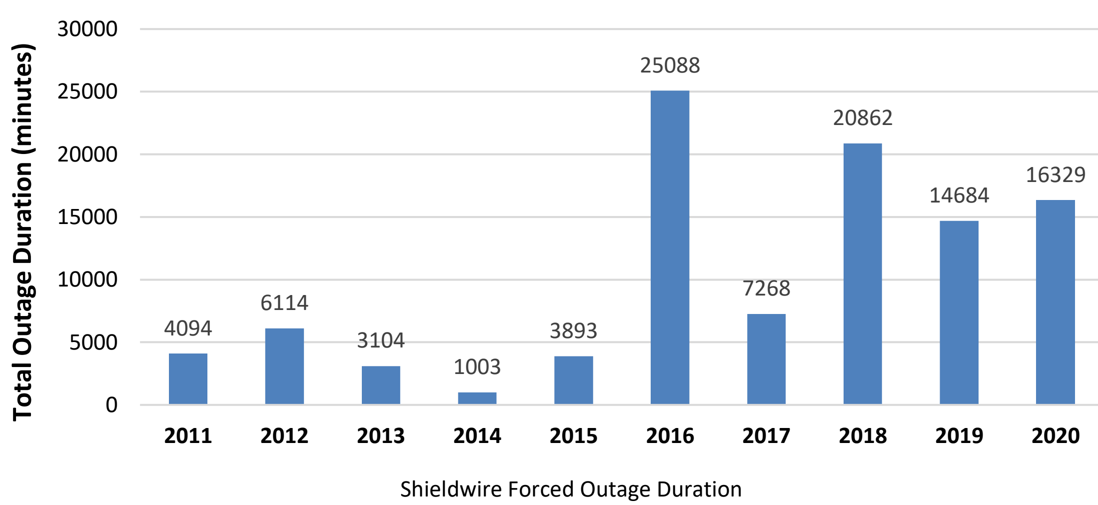

Figure 48: Duration of Shieldwire Related Outages

ASSET LIFE CYCLE

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 uses a condition-based asset management strategy to assess and prioritize the replacement of its shieldwire fleet. Age is used only as a criterion for identifying assessment candidates.

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 30 below.

Table 30 - 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.

With respect to shieldwire condition assessments, Hydro One primarily uses the Kinectrics LineVue inspection system, which is an economic method of traversing a span to assess shieldwire condition. Data collected is used to assess the condition of the shieldwire (based on estimated tensile strength reductions, etc.) without the need for an outage or intrusive testing.

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.

Currently, 8,967 circuit km (26%) of Hydro One’s shieldwire fleet has reached the age threshold for condition assessment but have not yet been assessed. These assessments are required to plan, schedule and execute replacements of poor condition shieldwire.

2.2.3.7 OTHER LINES ASSETS

ASSET DESCRIPTION / PURPOSE

Other transmission line assets include U-bolts, switches, and numerous other hardware components such as dampers and ground wires.

U-bolt Hardware

U-bolt hardware is the physical link between a transmission structure and insulator as shown in Figure 49. 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 49: 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).

ASSET DEMOGRAPHICS, CONDITION AND OTHER FACTORS

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 82,000 steel suspension circuit structures in the overhead transmission network containing U-bolts. About 33,500 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 120 line switches in the system, ranging in age between 1 and 100 years old.

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 50. Eventually the hardware will no longer have the mechanical strength to support the suspended insulator and conductor, leading to a catastrophic failure.

Figure 50: A Worn U-bolt

There are various external factors, such as wind, weather and circuit configuration, that can impact the rate of deterioration of U-bolt hardware. The age of U-bolt hardware alone does not reflect its physical condition. U-bolt hardware are visually assessed by either detailed helicopter inspection or climbing inspection to determine its physical condition.

Out of approximately 82,000 steel suspension circuit structures within the Hydro One transmission network, approximately 2644 circuit structures have been identified with U-bolts in poor condition and will require replacement. U-bolts are also replaced through other activities, such as Line Refurbishments and Insulator and Wood Pole Replacement programs.

U-bolt hardware condition assessment is based on visual inspections via Detailed Helicopter Inspection (DHI) and Climbing Inspection. Figure 51 below describes the condition of conductor

U-Bolt for Steel and composite circuit structures based on the wear percentage. A portion of the circuit structures under the category of “needs assessment” are located in no-fly zones.

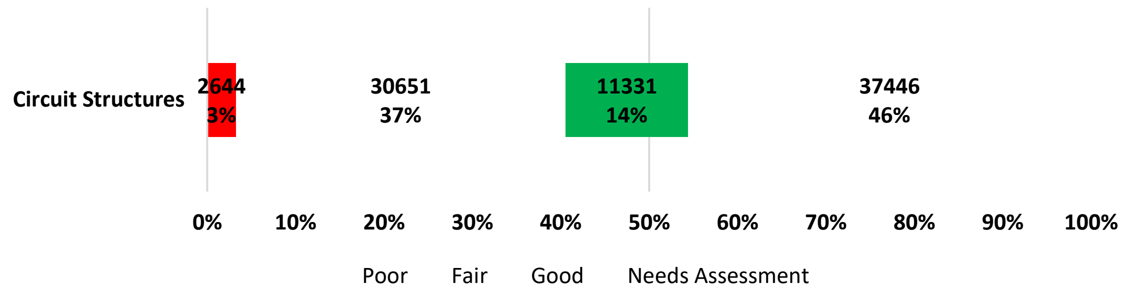

Figure 51: Condition of U-bolt Assets

Line Switches

Line switches are assessed and maintained every 10 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.

ASSET LIFE CYCLE

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.

Asset Inspection & 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. 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 younger 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 highway and road crossings where salt contamination is a concern.

Non-cyclical Maintenance Activities

DHI involves a low-speed aerial-based patrol to assess the condition of tower structure hardware, including U-bolts and other smaller components such as dampers and clamps. In this context, DHI is performed on circuits older than 50 years and where U-bolt hardware has not been replaced in the past 50 years. Circuits that contain U-bolt hardware that are assessed at 25% wear or more are to be re-assessed within 5 years from the time of the previous condition assessment. Circuits containing U-bolt hardware that are assessed at less than 25% wear are to be re-assessed within 10 years from the time of the previous condition assessment.

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. The general criteria to perform climbing inspection on a circuit section are similar to DHI.

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 support the insulator strings and conductors, and dampers that limit vibration of conductor.

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 and climbing inspection to assess the U-bolt condition of 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 the event that 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.

To minimize any customer impact, system reliability and public safety risk, Hydro One will continue to perform cyclical inspections to identify defects on the overhead line system as well as to perform asset condition assessment to identify poor condition assets. Poor condition U-bolts identified through DHI or climbing inspection will be replaced through the planned corrective program or through other major component replacement programs. Defects with imminent reliability or safety risk will be addressed through the demand maintenance program.

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 regarding the management of its transmission power system assets and have informed the proposed capital expenditure plan. In general, the studies show that Hydro One's practices and processes for managing transmission assets are aligned with industry best practices, Hydro One selects the appropriate assets for replacement, and Hydro One effectively executes capital work.

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

- Transmission Capital Project Execution Review - UMS
- Pole Replacement Program Study - Guidehouse and First Quartile
- Transformer Condition Assessment - EPRI
- Line Loss Assessment - Stantec

Additional studies and analyses related to other aspects of the TSP are discussed in the sections referenced below:

- Capital Expenditures and Reliability Performance – TSP Section 2.4 and 2.5
- CEA Reliability Performance – TSP Section 2.4 and 2.5
- Capital Expenditures and OM&A – TSP Section 2.8
- Capital Performance Report – TSP Section 2.9 Attachment 2

2.3.2 SUMMARY OF STUDIES AND FINDINGS

The third-party studies commissioned by Hydro One have been summarized below. The summaries include study findings, recommendations and implementation details. The studies are included as attachments to this section.

2.3.2.1 TRANSMISSION CAPITAL PROJECT EXECUTION – UMS

STUDY OVERVIEW

The UMS Group was engaged to 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. The UMS Group prepared a report entitled "Hydro One Networks Inc. - Transmission Capital Project Execution Review" (UMS Report), which is Attachment 1 to this section.

In order to evaluate Hydro One's capital delivery model's effectiveness the UMS Group:

- Designed and administered an assessment framework to gauge maturity across 10 performance domains;
- Conducted a series of interviews with 24 Hydro One representatives across all relevant lines of business ranging from front line supervisor to Vice President;
- Reviewed relevant Hydro One reports, procedures, and project performance data;
- Identified and engaged a comparator group of 12 Canadian and U.S. electric utilities with substantial transmission assets; and
- Surveyed the comparator group to determine Hydro One's standing across each of the performance domains.

STUDY FINDINGS

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

Table 1 - Key Study Findings

Key Study Findings	Reference
Hydro One is second quartile or better in seven of the ten performance domains including Cost Management, Scope Management, Resource Management, Risk Management, Quality Management and Contract Communications.	UMS Report, pp. 14-20
Hydro One is at the median in two domains: Schedule Management and Integration Management.	UMS Report, pp. 16, 21
Hydro One is approaching the third quartile in Technology Enablement.	UMS Report, p. 22

The UMS Report highlighted opportunities in both the scheduling management and technology enablement performance domains. Hydro One's plans to improve in each of these performance domains are discussed in the following paragraphs.

Hydro One has an initiative underway to improve field scheduling management, which will improve project schedule visibility and management. This improvement will assist the executing lines of business in developing more detailed schedules, which will improve their ability to report schedule performance by consistently measuring work completion against plan. As part of implementing this initiative, necessary improvements to the scheduling tools currently used in the field are underway.

In addition to improving the field scheduling tools and integrating them with the master project schedule housed in Primavera P6, Hydro One has started the discovery phase to select a project lifecycle management tool that will pull disparate data sources together in one place to facilitate improved reporting on project performance as well as provide project managers with a simplified way to manage their projects. This tool will provide project managers with visibility to cost and schedule data in one location which will improve forecasting capabilities through visibility and improved tools.

These initiatives are further described in the Transmission Capital Work Execution Strategy found at TSP Section 2.10.

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 cost of replacing transmission wood poles. Their report, entitled "Transmission Pole Replacement Benchmarking," is Attachment 2 to this section.

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

- Formalized study design by identifying the comparator utility groups, defining the characteristics for comparison and developing comparison metrics;
- Gathered Hydro One and comparator group data;
- Validated and normalized the data to put US dollar results into Canadian dollars, to calculate a replacement cost per pole;
- Analyzed the data to prepare statistical findings; and
- Developed comparisons between Hydro One and the comparator group.

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
Hydro One's wood pole replacement work practices, including selection of poles and evaluation of associated equipment (e.g., crossarms, insulators, and hardware) for replacement are in line with those of the comparator group.	Report, p. 9
Hydro One's transmission wood structure replacement costs are $27,450 per pole, well below the mean of $32,882 for the comparator group.	Report, p. 9
Hydro One's expected wood pole service life of 50 years is above the mean value (44 years) and at the median value of the peer group.	Report, p. 10
The average age of Hydro One's transmission wood pole structures (35 years) is similar to the average age of the comparator group (38 years).	Report, p. 11
The age distribution of Hydro One's wood pole is broad with Hydro One having relatively high percentages of poles both over 60 years old and under 20 years old.	Report, p. 11
During the last five years, on average Hydro One replaced 2.1% of its wood poles annually. The comparator group mean was 2 .6%. Hydro One expects to replace 2.9% of its poles per year over the next five years compared to the comparator group mean of 2.2%. Given the age and condition of Hydro One's wood poles, "a marginally higher replacement rate is expected."	Report, p. 13

2.3.2.3 TRANSFORMER CONDITION ASSESSMENT – EPRI

STUDY OVERVIEW

Electric Power Research Institute (EPRI) undertook a study to assess the condition of 208[1] Hydro One transmission substation transformer tanks. Their report, titled "Power Transformer Condition Assessment" is Attachment 3 to this section.

To evaluate the Hydro One transmission substation transformers, EPRI:

- Gathered Hydro One transformer condition and description (nameplate) data; and
- Assessed the condition of the transformers across four indices (Normal Degradation, Abnormal Thermal Degradation, Abnormal Electrical Degradation, and Abnormal Core Degradation), using Hydro One's data and EPRI's PTX Transformer Fleet Management Software.

STUDY FINDINGS

The Power Transformer Condition Assessment's findings are summarized in Table 3.

Table 3 - Key Study Findings

#	Key Study Findings	Reference
1	EPRI confirmed degradation in the main tank for 155 transformer tanks, consistent with Hydro One's evaluation of transformer main tank oil test results.	Report, p. 2
2	17 Transformer tanks were deemed to be in marginal condition.	Report, p. 2
3	36 Transformer tanks were not deemed to be in poor or marginal condition based on the main tank data provided and were likely deemed in poor condition by Hydro One based on factors other than the main tank oil test results including Load Tap Changer (LTC) Dissolved Gas Analysis (DGA), oil leaks, LTC issues, cooling system issues, etc.	Report, p. 3

[1] 208 transformer tanks relates to 198 transformers (3-phase units)

2.3.2.4 LINE LOSS ASSESSMENT – STANTEC

STUDY OVERVIEW

Stantec Consulting Ltd. (formerly Teshmont Consultants LP) completed a review of Hydro One's transmission line loss processes in accordance with the settlement accepted by the OEB in Hydro One Transmission's last rate application.[2] Their report titled "Hydro One Transmission Line Loss Review" is Attachment 4 to this section. Further information on Transmission Line Losses and Hydro One's response to the settlement terms is found in TSP Section 2.6.

In order to review Hydro One Transmission's line loss processes with a view to assess the principles and completeness of such processes and identify potential opportunities to cost-effectively reduce transmission line losses, Stantec:

- Reviewed industry reports on transmission line losses including:
    - EPRI's report on Hydro One Transmission Losses[3]
    - The National Grid Strategy Paper[4]
    - The Council of European Energy Regulators 1st and 2nd reports on power losses[5]
    - Documentation from the IESO's Transmission Losses Engagement[6]
- Reviewed Hydro One's Transmission Line Loss Guideline;[7]
- Interviewed Hydro One representatives; and

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[2] EB-2019-0082 Decision p 58-59: Settlement term 5: At the end of the IESO stakeholder consultation and issuance of the IESO report, if the IESO determines that it will not proceed to engage an independent third party to review the IESO's and Hydro One's processes, Hydro One will initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at its next rate application. This review would aim to identify any additional opportunities to cost-effectively reduce transmission line losses, including through improved processes, option analysis methodologies, documentation, and reporting, and would invite input from stakeholders."

[4] National Grid Strategy Paper to Address Transmission Licence Special Condition 2K: Electricity Transmission Losses, Reporting Period: 1 April 2013 to 31 March 2021, Published November 2013, Revised September 2014

[5] C17-EQS-80-03 CEER Report on Power Losses – October 2017, C19-EQS-101-03 2nd CEER Report on Power Losses – March 2020

[6] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Losses.

[7] Provided in Stantec's report found in Attachment 4, Appendix A.

- Participated in a stakeholder session with intervenors from Hydro One's previous transmission rate application to discuss Stantec's preliminary findings and incorporate comments in their report.

STUDY FINDINGS AND RECOMMENDATIONS

The Transmission Line Loss Review's findings and recommendations are summarized in Table 4 and Table 5.

Table 4 - Key Study Findings

#	Key Study Findings	Reference
1	Hydro One's practices related to transmission line losses are generally aligned with the recommendations outlined in the National Grid Strategy Paper, CEER 2017 Report, and CEER 2020 Report in relation to transmitters.	Report, p. 13
2	Stantec concurs with the findings in the EPRI report which concludes that Hydro One's design practices are generally consistent with industry best practices for line loss mitigation.	Report, p. 13
3	Stantec found the Hydro One Transmission Line Loss Guideline provides a reasonable approach for the evaluation and selection of the preferred investment alternatives considering the cost of losses.	Report, p. 13
4	Stantec concluded that Hydro One follows industry best practices with respect to transmission line loss management. Hydro One's Transmission Line Loss Guideline provides a reasonable, clear and efficient process for the purposes of incorporating the cost of losses into alternatives evaluation and selection.	Report, p. 14

Table 5 - Study Recommendations

#	Recommendations	Reference
1	Ensure implementation and consistent use of the Transmission Line Loss Guideline for new investments that impact transmission line losses.	Report, p. 14
2	Track the number of projects that have been assessed for transmission line loss mitigation and the associated MW reduction in losses as documented in approved business cases.	Report, p. 14

Hydro One has implemented the study's recommendations as follows:

Recommendation 1

Hydro One has provided the Transmission Line Loss Guideline to all transmission planners to ensure that transmission line losses are consistently assessed when evaluating investment alternatives.

Recommendation 2

Hydro One continues to assess and document transmission line losses. Beginning in 2022, Hydro One will track the number of projects that have been assessed for transmission line losses and the associated MW reduction.

2.3.3 ATTACHMENTS:

Attachment	Report
1	Transmission Capital Project Execution - UMS
2	Pole Replacement Program Study - Guidehouse and First Quartile
3	Transformer Condition Assessment - EPRI
4	Line Loss Assessment - Stantec

Final Report

Hydro One Networks Inc.

Transmission Capital Project Execution Review

Submitted by

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March 2021

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SECTION I – EXECUTIVE SUMMARY

In connection with Hydro One Networks Inc.'s ("HONI") Custom Incentive Rate ("CIR") application for 2023-2027 transmission and distribution rates, UMS Group has undertaken a study to examine the processes used by HONI to plan, approve, execute, and monitor transmission capital projects and the results HONI has achieved in executing its portfolio of transmission capital projects.

In accomplishing these objectives, UMS Group:

- Conducted a series of interviews with HONI individuals in relevant lines of business (e.g., Project Control, Project Delivery, Station Services, Transmission Lines, and Station Construction),

- Reviewed relevant reports, procedures, and project performance data (***see Appendix B***),

- Identified and recruited a Peer Group Panel of 12 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"[1]), 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," the results of this study yielded insights from both industry and HONI-specific perspectives.

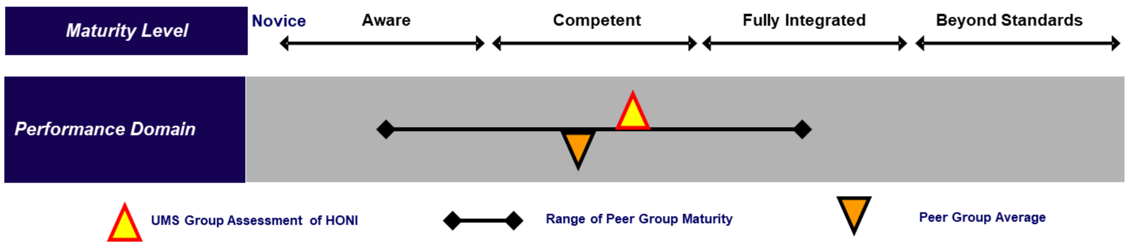
[1] Initially published in 1996 and recently updated in 2017, the PMBOK is a fundamental resource for effective project management in any industry and has gained increasing acceptance as a standard in the utility industry for measuring project management effectiveness.

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



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 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 the 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 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
Technology Enablement	Includes use of enterprise-wide software and / or applications to facilitate the 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 detailed discussion provided in Appendix D.

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 slippages 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, UMS Group conducted the interviews and surveys, asking open-ended questions and reviewing information / data to determine each utility's position on the Maturity Rating Scale across each of the 10 Performance Domains.

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.

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

Once assigned scores, the basis for comparing HONI's performance in each Performance Domain was established.

Performance Comparisons and Assessments

Applying the above approach and methodology, and based on the study results, relative to a Peer Group Panel of 12 electric utilities across North America, HONI is second quartile or better in seven of the ten performance domains, at the median in two domains (Schedule Management and Integration Management), and at the cusp of the third quartile in Technology Enablement. Table I-3 presents these results, indicating HONI's Maturity Rating Scale Score and its position relative to the Peer Group Panel for each of the 10 Performance Domains.

Table 1-3: Performance Comparison

Performance Domain	Maturity Rating Scale Score	Quartile			
		Bottom	3rd	2nd	Top
Cost Management	4.25				
Scope Management	4.50				
Schedule Management	3.25				
Resource Management	3.50				
Risk Management	3.50				
Quality Management	3.50				
Contract Management	4.25				
Communications Management	4.25				
Integration Management	3.25				
Technology Enablement	2.75				

Summary

UMS Group notes both areas of strength and opportunities for improvement:

- *Areas of Strength*: According to HONI, the Transmission Capital Efficiency Initiative, developed in 2016 and rolled out in 2017, focused on defining and documenting the expectations at each step of the asset deployment process, providing clarity to stakeholders as well as a mechanism for monitoring quality and performance over time. The intent was to drive efficiency in execution timelines by reducing rework, increasing collaboration, improving alignment across HONI, and ensuring accountability and efficiency throughout the process. We note in our review (Section IV, "Study Results") a resulting strong focus on cost management, rigorous project-based risk cost assessments, a disciplined approach to managing scope, and a well-defined stage gate process (from initial project conception through execution) with clear expectations regarding the state of design and accuracy of corresponding estimates.

- *Opportunities for Improvement*: In comparing current state to that of a mature project management process, UMS Group notes improvement opportunities in the areas of project scheduling (from both risk management and schedule status perspectives) and making targeted enhancements to HONI's Operations / Information Technology (IT / OT) platforms to strengthen cost-schedule integration and streamline reporting efforts.

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, UMS Group combined its industry perspective regarding project management (informed by several business process design efforts, practical "hands on" experience by our expert witness, and insights gleaned from UMS Group facilitated Global Learning Consortia) with assessment frameworks / methodologies formed during 30+ years of performing comparative analyses.

To establish context for the analyses and conclusions contained within this report, UMS Group:

- Reviewed relevant reports, procedures, and performance data provided by HONI (***see Appendix B***).
- Was provided complete access to HONI's technical and management staff in the form of conference calls (***see Appendix C***),
- 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 D***), and
- Identified and recruited a Comparator Group (Peer Group Panel), comprised of 12 electric utilities, against which comparisons in executing projects could be made.

With the context established, UMS Group 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, UMS Group 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.

We have also provided additional appendices 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.

UMS Group Qualifications

UMS Group, headquartered at 300 Interpace Parkway, Parsippany, NJ, 07054, was retained as an independent expert. With over 30 years of experience conducting comparative performance assessments for the global utilities industry, UMS Group 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. UMS Group 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, UMS Group 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 UMS Group's qualifications and those of the individuals assigned to this effort.

SECTION III – PROJECT APPROACH

UMS Group'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

	Project Mobilization and Initial HONI Assessment	Comparative Review	Evaluation and Results
Key Tasks	Task 1: Mobilized the Team / Started the Project Task 2: Conducted Documentation Review and Topical Interviews / Group Sessions	Task 3: Conducted Comparative Analysis	Task 4: Performed Evaluation Task 5: Presented Results
Focus	HONI's Current State regarding: • Methods / systems / practices for tracking, trending and reporting on Project / Portfolio performance • Processes and practices to manage Projects / Portfolio (ranging from Project Identification through Closeout, including Governance and Enabling Technologies)	• HONI's transmission capital project execution process, including planning, design, project controls, and governance, relative to industry standards and the processes used by companies in the Peer Group Panel	• Results of an End-to-End review of HONI's Transmission Capital Project Execution Process • Applying a PM Maturity Assessment Framework, HONI's position relative to the Peer Group Panel and PMBOK Standard
Deliverables	• Information / Documentation request • Completed HONI interviews / HONI SME input on Transmission Capital Project Execution Process • Identification of the Peer Group Panel	• Qualitative Comparisons (refer to PM Maturity Assessment Framework) • Explanation of apparent variances between HONI and the Peer Group Panel	• Final Presentation and Report

Through three phases of the study, UMS Group performed five main tasks:

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

2. Reviewed relevant documentation and interviewed 24 individuals, ranging from Senior Foreman to Vice President, and covering the organizations that play a primary role in the execution of Transmission Capital Projects.

3. Conducted the review, applying an industry accepted standard for Project Management and compared 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 report and discussed results with HONI to assure an accurate view of HONI's current state and share perspectives from other Transmission organizations.

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

Consistent with approaches used with other electric transmission organizations, UMS Group adopted the framework outlined in the Project Management Institute's ("PMI")[2] 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. We then established a Maturity Rating Scale, tailored to accommodate the previously mentioned 10 performance domains. In taking this approach we were able to conduct 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 UMS Group 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 D.

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:

- Substantial amount of Transmission assets,
- Serve a rural territory,
- Have recently embarked on a project management improvement initiative,
- Have experienced / is anticipating a notable increase in transmission capital work, and

[2] **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.**

- Achieve an appropriate balance between Canadian and US utilities.

With these criteria in mind, UMS Group approached an initial list of 16 potential comparators to participate in the study and was able to obtain participation by 12. Our experience has shown that this number of participants will provide meaningful results. Therefore, the resulting Peer Group Panel of 12 utilities, presented in Table III-1 represents a reasonable and valid comparison group for Hydro One.

Table III-1: Peer Group Panel

ATCO Electric	Louisville Gas and Electric / Kentucky Utilities
BC Hydro	Portland General Electric
Evergy	Pacific Gas and Electric
DTE Energy	Public Service Electric and Gas
FirstEnergy (OH, PA, and NJ Operating Companies)	SaskPower
Hydro Quebec	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, UMS Group took a real-time interactive approach to collecting information from HONI and the Peer Group Panel.

- In structuring the interviews within HONI, we presented a listing 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 Workflow
  - Project / Portfolio Performance Tracking (leading and lagging indicators)
  - Resourcing Strategy and Planning

Contractor/Vendor Management

Portfolio and Project Risk Management

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.

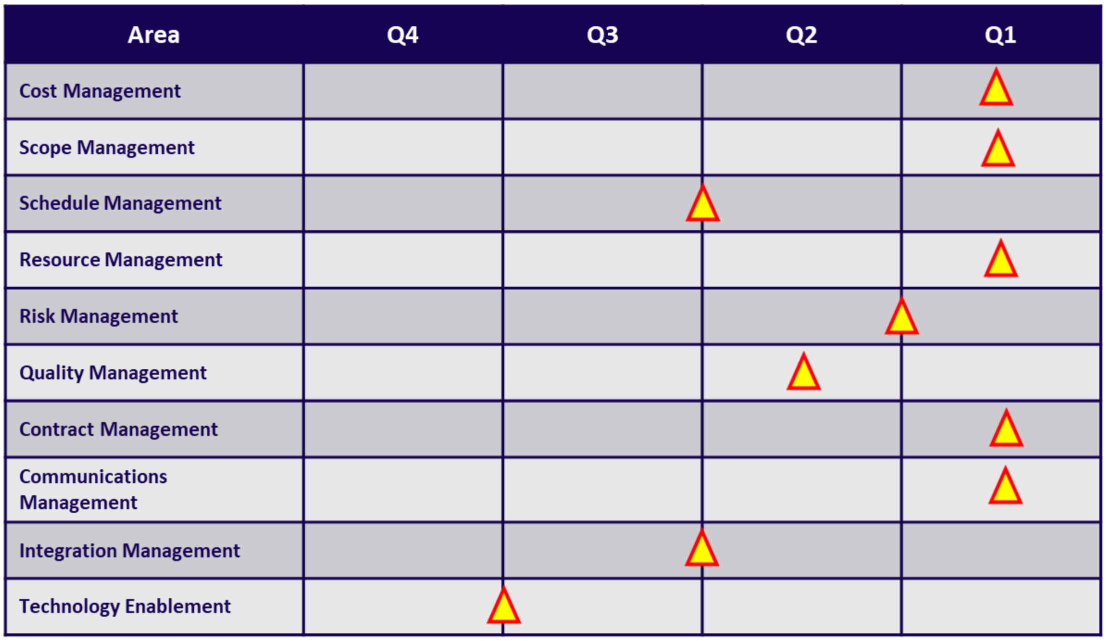
- With respect to the Peer Group Panel, interviews were conducted, applying open-ended questions, thus providing sufficient information to ascertain current state across the 10 performance domains.

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, the Hydro One's Project Management practices compare well to the Peer Group Panel, as Hydro One is at or near top quartile levels for six performance domains and other than Technology Enablement, the remaining are at the median level or better.

Figure IV-1: Summary of Peer Group Panel Comparisons



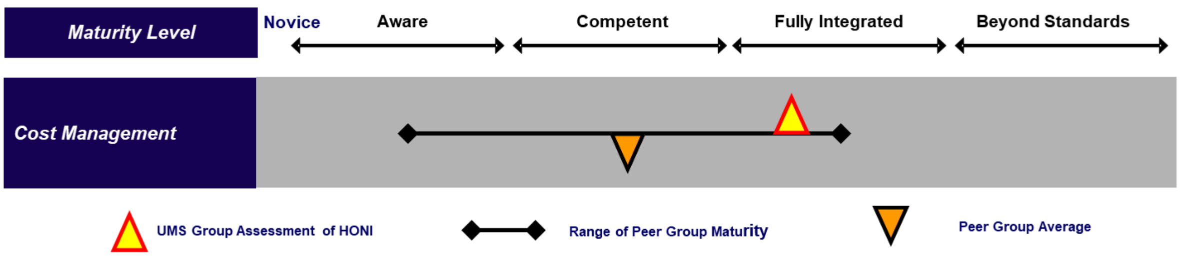
The following discussion expands upon Figure IV-1, portraying Hydro One's comparisons to the Peer Group Panel Averages and its relative positioning on the Project Management Maturity Scale Rating within each Performance Domain, with commentary to provide more context to the assessments.

Cost Management

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

HONI's approach to managing project costs aligns with other industry leaders, emphasizing (1) 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 and supporting business cases, and (4) providing actionable reports to Senior Management.

Figure IV-3: Cost Management Comparisons

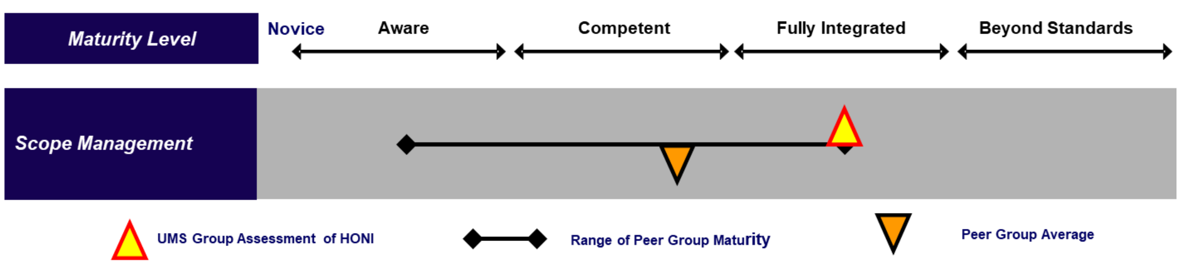


Scope Management

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

HONI's approach to managing scope exceeds that exhibited by the Peer Group Panel. The stage gate process leading to the establishment of a project baseline when engineering is approximately 30 percent complete, linkage of risk contingencies to the scoping discussion, and the advent of coordination meetings between planning, construction, engineering, and operations early in the process are indicative of "best practices," and substantiate HONI's status as "Fully Integrated."

Figure IV-5: Scope Management Comparisons

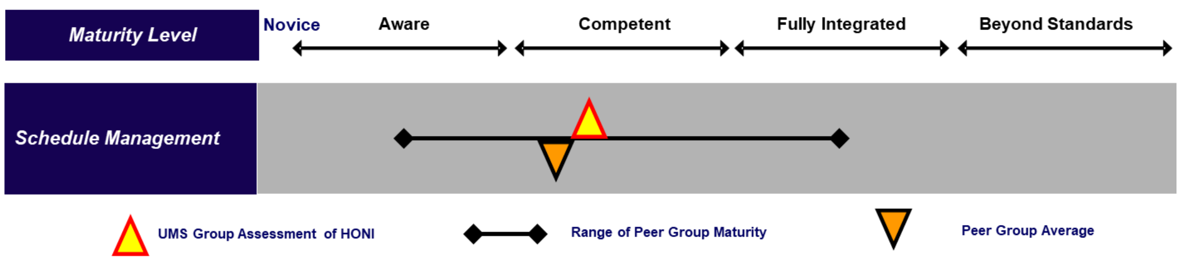


Schedule Management:

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

HONI receives slightly less than a "Competent" rating in schedule management. The actual mechanics of scheduling (e.g., establishing a hierarchy of schedules, developing activity networks, and estimating durations) and choice of an IT enabling platform (P6 software solution) comport with industry standards. However, being able to (1) achieve full integration (end-to-end scheduling from initial design to commissioning and activity-based cost / resource planning) and (2) apply further rigor in reporting progress (e.g., earned value or percent complete) represent opportunities for improvement.

Figure IV-2: Schedule Management Comparisons

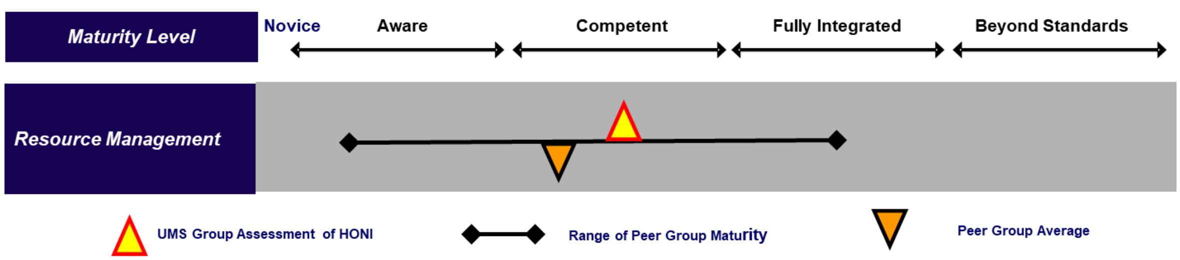


Resource Management

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

HONI is 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. In that sense, HONI comports with industry standards and compares favorably to the Peer Group Panel (top quartile performer).

Figure IV-4: Resource Management Comparisons

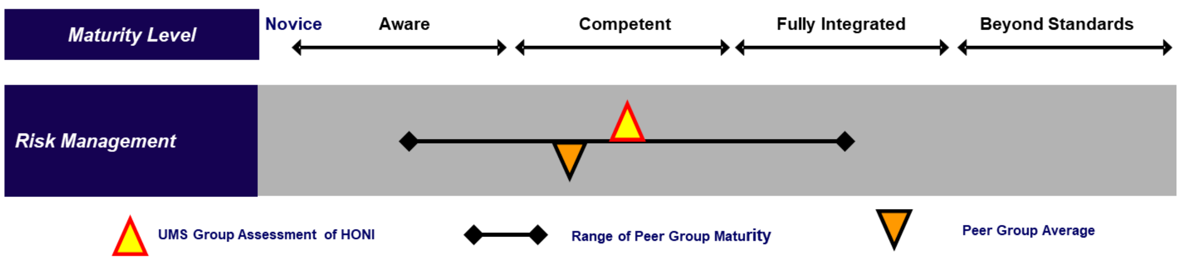


Risk Management

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 in the "Competent" category and bordering between top and second quartile in comparison to the Peer Group Panel. The factors driving this seemingly modest maturity scale rating (given its comparative position as nearly top quartile) are (1) the relatively immature state of the peer group panel in managing risk (particularly around capital projects), yet (2) the foundation put in place by HONI resulting from the Transmission Capital Efficiency Initiative. The framework and methodologies for identifying risks, establishing contingencies, and creating risk registers at the project level are already in place.

Figure IV-6: Risk Management Comparisons



Quality Management

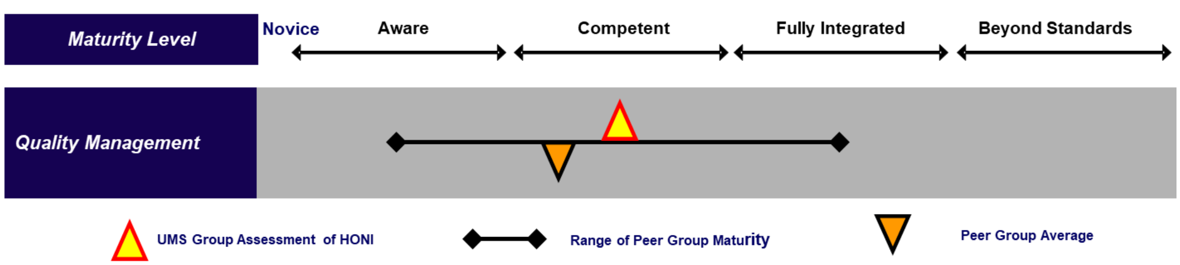
Includes Planning the Quality Management Process, Performing the Quality Assurance Process, and Controlling the Quality Process.

HONI's rating of "Competent" and comparative position as second quartile in this performance domain are based on the integration of QA / QC processes throughout the end-to-end project management process, including:

- Within Engineering, a peer review of all designs prior to issuance with an emphasis on compliance to specifications and design standards,
- Within Construction, as part of the construction readiness phase, assigning administrative and inspection check points to be activated during construction, and
- When contracting work, applying experienced field inspectors to monitor quality, progress, and safety throughout the project with the goal of ensuring compliance with specific contractual criteria and expectations.

Improvement opportunities include establishing (1) a repository to capture and trend the results of in-process inspections or otherwise identified deficiencies, and (2) metrics to directly measure, trend, and highlight actions to improve quality.

Figure IV-7: Quality Management Comparisons



Contract Management

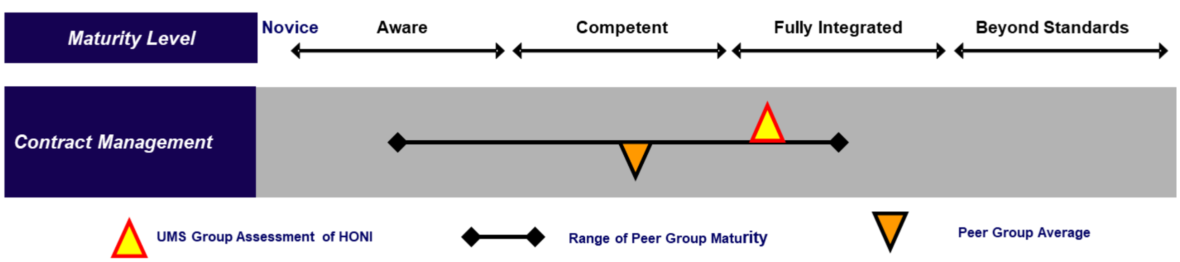
Includes Planning Procurement, Conducting Procurements, Controlling Procurements, and Closing Procurements.

HONI is nearing a "Fully Integrated" rating and ranks in the top quartile compared to the Peer Group Panel), starting with the formation of a dedicated group, tasked with clarifying roles and responsibilities and standardizing project administrative requirements. Specific observations leading to this comparably high 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 Owner's Requirements and RFPs, and

- 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.

Figure IV-8: Contract Management Comparisons



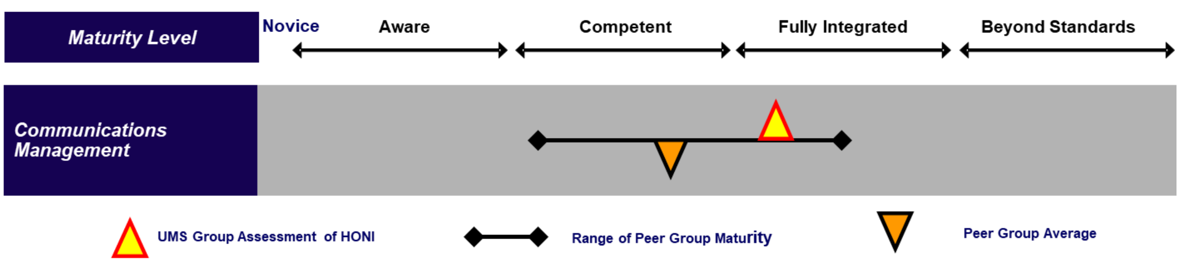
Communications Management

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).

HONI is approaching "Fully Integrated" status and ranks in the top quartile compared to the Peer Group Panel, as it has the basics covered in managing communication within the project and with all internal and external stakeholders:

- The stage gate process itself provides a reporting regimen and cadence in strategically managing and communicating status across the organization,
- There exists a well-defined protocol for tactically reporting project performance, with appropriate thresholds for escalation to Executive Management.
- The COMSE[3] process (initiated in the earlier stages of a project) calls for internal stakeholder engagement to address issues such as constructability, operability, maintainability, safety, and the environment, and
- Community Relations plays 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



[3] **COMSE is an acronym for Constructability, Operability, Maintainability, Safety, and Environment, a meeting held early in the project formulation process to assure input from these key internal stakeholders.**

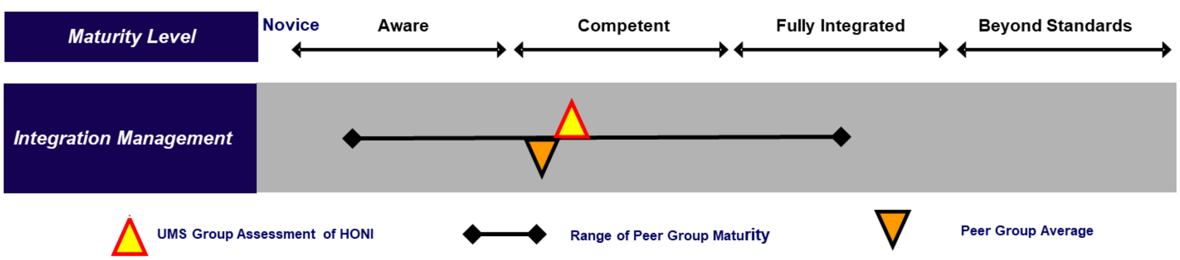
Integration Management

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.

As noted in the below comparisons (Figure IV-10), HONI is approaching a rating of “Competent” and ranks at the median in comparison to the Peer Group Panel:

- HONI effectively manages the trade-offs between cost, schedule, and quality, albeit requiring a significant amount of manual intervention to compensate for lack of fully integrated IT / OT enabling technologies,
- Role clarity starting with the Transmission Capital Efficiency Initiative and now continuing as part of the Transmission Capital Delivery Model Enhancement Initiative, is beneficial, and
- Continued emphasis on the proper closing out of projects and associated update of all relevant documentation will facilitate the design input processes for future modifications.

Figure IV-10: Integration Management Comparisons



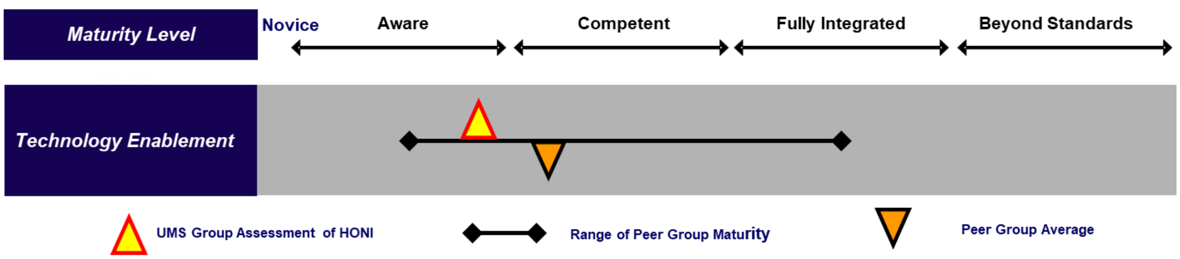
Technology Enablement

Includes use of enterprise-wide software and / or applications to facilitate the effective management of the end-to-end Project Management process.

In approaching a rating of "Competent" and straddling the third and fourth quartile in comparison to the Peer Group Panel, Technology Enablement represents HONI's biggest opportunity to improve. Specific observations contributing to this assessment include

- Lack of a robust Project Cost Accounting platform to automate the management and reporting of cost data,
- 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.

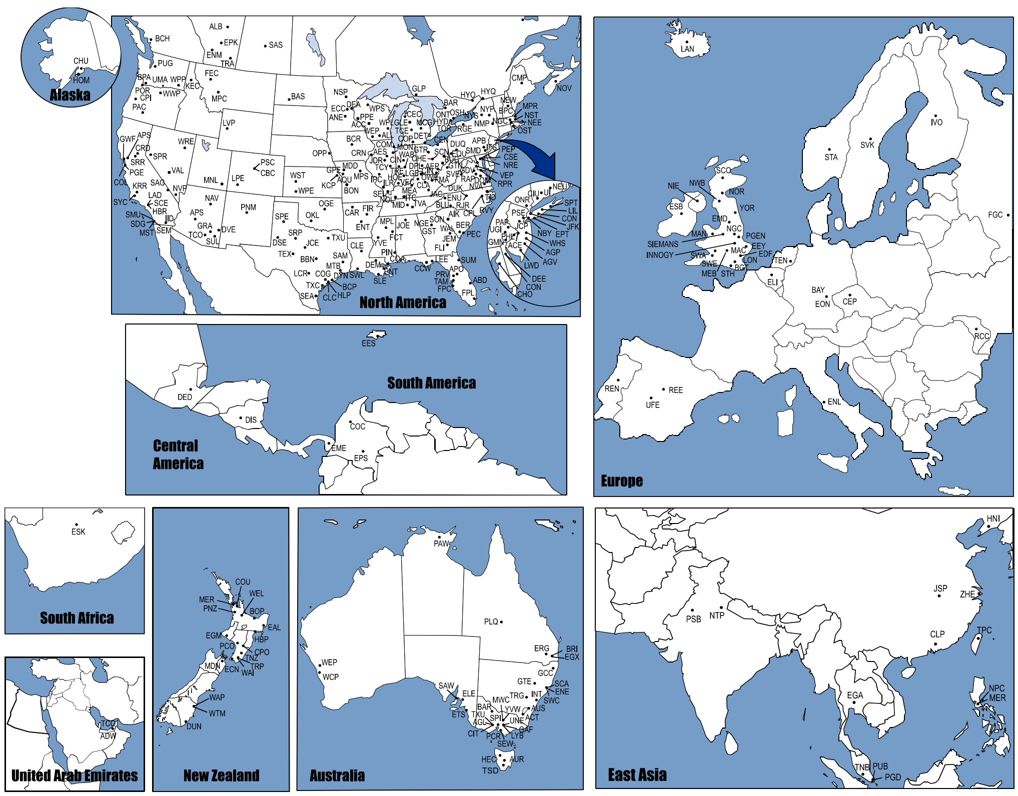
Figure IV-11: Technology Enablement Comparisons



APPENDIX A – UMS GROUP QUALIFICATIONS

UMS Group has been a leading provider of utility benchmarking services for 31 years. UMS conducted its first utility benchmark in 1989 and began its first Benchmarking and Best Practice Consortia in 1990 (PACE - Performance and Competitive Excellence).

Since that time, UMS Group has continued to be a global leader in electric industry multi-company assessment and benchmarking studies. The key differentiator in our performance assessment approach is the depth of our understanding of industry best practices to drive operational performance. Our benchmark programs 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*.



UMS Group's performance database developed and maintained over the past 30 years and its UMS Group-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.

Apart from these credentials, UMS has accomplished similar projects with clients in various markets around the world.

Experience Summary of Project Lead – Jeffrey W. Cummings

Mr. Cummings has over 40 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

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 a proposed investment's value and its contribution to overall corporate strategy as well as the risk should a specific investment 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 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 – HYDRO ONE PROVIDED INFORMATION

- Role Kits for the following positions:
  - Project Manager
  - Contracts Procurement
  - Construction
  - Cost Controller
  - System Operations
  - Scheduler
  - Project Engineer
  - Planning
  - Outage Planning
  - Estimator
  - Environmental Planner
  - Community Relations
  - Station Services
- Project Closure Examples
- Technology Roadmap
- Construction Performance Evaluation Process
- Organization Chart
- Program and Project Approval Procedure

APPENDIX C – HYDRO ONE INTERVIEWS

(Listed in the order they were held)

Title
Manager, Project Controls
Manager, Major Projects Southwest / Bruce
Manager, Project Risk Management
Manager, Major Projects
Director, Project Delivery
Manager, Portfolio Reporting
Director, Station Services
Director, Portfolio Management
Vice President, Transmission and Stations
Manager, Contract Management and Project Engineering
Manager, Contract Management
Director, Transmission Lines
Director, System Planning
Director, Station Construction
Superintendent, CIM
Manager Construction Operations
Manager Scheduling
Superintendent of Construction Services
Planning Manager
Manager, Estimating and Project Planning
Protection & Control Supervisor
Director Transmission Control and Operations Planning
Manager, Conceptual Engineering
Senior Electrical Foreperson- Stations

APPENDIX D – 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 D-1 (following page) summarizes the 10 Performance Domains, against which UMS Group assessed HONI's relative maturity scale rating and compared its performance to the 12 electric utilities that comprised the Peer Group Panel.

Table D-1: Project Management Performance Domains

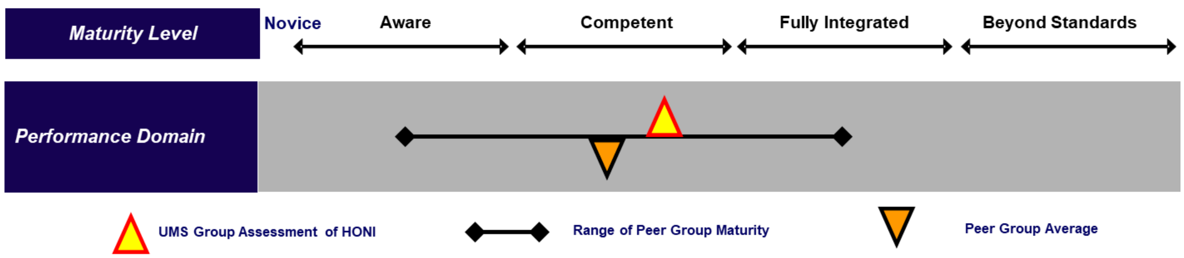
Performance Domain	Description	Objective
Cost Management	Includes Planning Cost Management, Estimating Costs, Determining the Budget, and Controlling Costs	Complete the project within a planned budget
Scope Management	Includes Planning the Management of Scope, Collecting Requirements, Defining the Scope 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 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 the 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 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 the 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 D-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 D-1: Maturity Scale Rating Framework



In the hypothetical presented in Figure D-1, HONI is shown as competent in this generic performance domain (approaching "fully integrated") and slightly better than the average rating for the Peer Group Panel. The Peer Group Panel ranges between "aware" and "fully integrated."

Figures D-2 through D-11 convey the actual definitions used in determining the placement of HONI and each Peer Utility in this study.

Figure D-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 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 D-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 D-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 slippages 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 D-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 supporting 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 D-6: Risk 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 Management beyond Level 4. Lessons learned are captured and incorporated into existing processes.

Figure D-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 D-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 process 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 D-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 largely 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 D-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 D-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.

Transmission Pole Replacement Benchmarking

Prepared for: !

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January 24, 2021

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Executive Summary

The consortium of Guidehouse Canada Ltd. (Guidehouse) and First Quartile Consulting (1QC or First Quartile) has conducted a benchmarking study for Hydro One Networks Inc. (Hydro One or HONI) regarding the replacement rates and costs of transmission wood poles.

This report provides an overview of the study approach (including the identification and recruitment of comparator utilities, the selection of analytical metrics, the method for gathering and summarizing the data) and study results, which provide insights into the transmission pole replacement costs and rates of Hydro One relative to comparator utilities. Primary findings from the study are highlighted below.

- Hydro One and the comparator utilities have a similar approach to wood pole replacement (including end-of-life pole determination based on condition assessment and assessment of equipment replaced in conjunction with the poles).
- Hydro One's average unit cost to replace its transmission wood poles is $27,450, below the comparator group mean of $32,882 per pole.
- The expected service life of Hydro One's wood poles is at the median of the comparator group and slightly above the mean.
- The average age of Hydro One's wood poles is at the median of the comparator group and slightly below the mean.
- The age distribution of Hydro One's wood poles is unique, with a higher percentage of poles installed before 1960 and after 2000 than the majority of the comparator group, which creates a need for additional replacements.
- Hydro One's replacement rate over the past 5 years has been just below the mean, and for the next 5 years is forecast to be above the mean of the comparator group.

1 Introduction

1.1 Study Objectives

This study provides a comparative analysis of Hydro One's practices and unit costs for transmission wood pole replacement among a sample of comparable North American utilities. In brief, the study was designed to:

- Determine Hydro One's practices and unit costs for transmission wood pole replacement; !
- Benchmark those practices and costs relative to a comparator group of utilities

1.2 Overview of Approach

Guidehouse and First Quartile identified a peer group of utilities to represent the transmission utility industry and identified the relevant business and operational characteristics that would be useful for comparisons. Specifically, elements of this effort were structured to:

- Include a representative grouping of comparator 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 the annual Transmission and Distribution benchmarking program conducted by First Quartile, with its existing participant group and underlying database of cost and demographic information, and also involved additional activities that included reaching out to certain utilities that are not part of that annual program.

The direct work of the study involved gathering the required demographic and operating data from Hydro One and the comparator utilities, and then normalizing that data to enable fair comparisons. The study included the development of a series of graphs of relevant metrics, and an analysis of the various graphs to draw conclusions about the results.

1.3 Content of Report

The report is organized in the following sections:

Section 2: Benchmarking Process, which provides insight about the benchmarking process used for peer selection, data gathering, normalizing factors used, and analysis conducted.

Section 3: Benchmarking Observations, which summarizes the findings related to costs, overall demographics, and replacement rates of transmission wood poles.

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 the context of comparable organizations and operations is important to normalize findings in such a way that data, trends and findings can be understood and lead to insights.

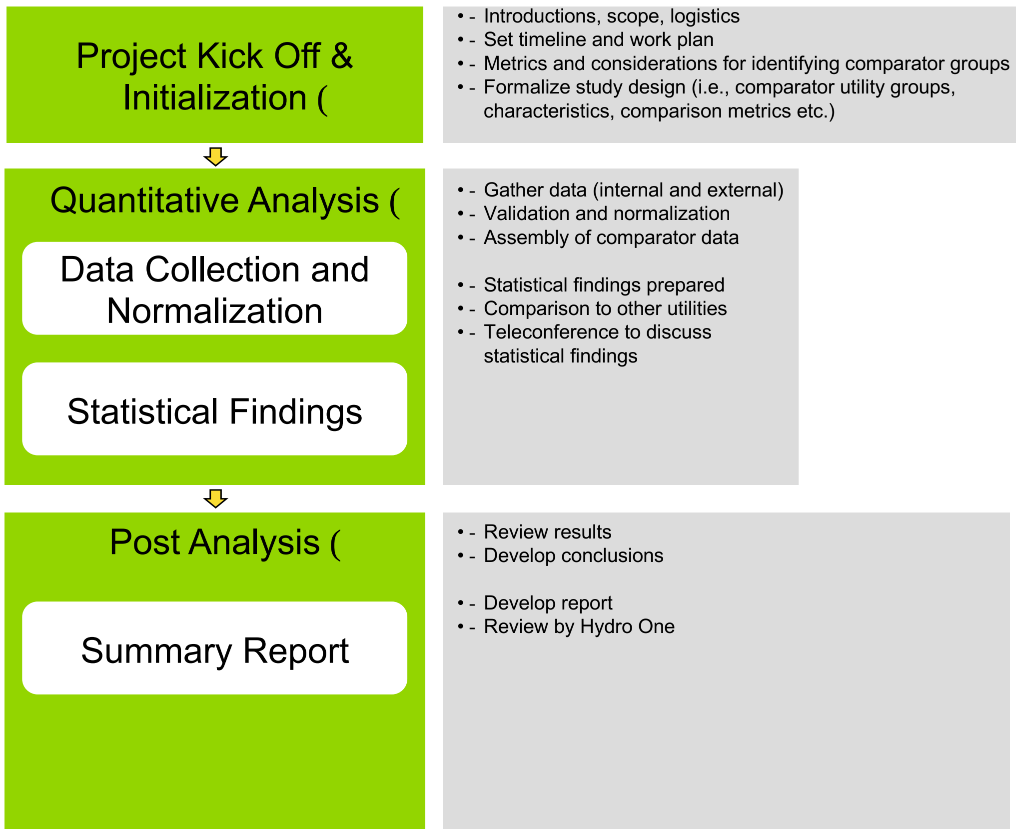
For this study, benchmarking was conducted to obtain information from comparator companies with sufficient details and transparency to understand the practices of those comparator companies from an industry perspective, in order to identify similarities to or differences with Hydro One. There are four sub-sections within this section.

- Overview – a brief overview of the primary steps in the benchmarking process
- Information collected – the data gathered for the comparisons, both from Hydro One and the peer group
- Comparator group selection – Descriptions of the Canadian and U.S. Transmission utilities included in the study
- Normalizing factors – number of wood transmission poles and currency exchange rates used for normalizing utility data for fair comparisons

2.1 Overview

The study was structured to provide a repeatable analysis that would give an accurate representation of Hydro One's transmission wood pole replacement costs in comparison to other transmission providers in a consistent manner. The major steps in the process are shown in Figure 1 below:

Figure 1 -- Project Approach



- **Project Kickoff and Initialization** – Determining the appropriate comparator group, the relevant demographic data, and the metrics for making the comparisons.
- **Quantitative Analysis**
  - Data Collection and Normalization – Gathering data through a detailed questionnaire directly completed by participating utilities, followed by normalization and data validation.
  - Statistical Findings – creating statistical summary graphs comparing results.
- **Post Analysis** – Review the results, draw out relevant observations about Hydro One demographics, performance, and practices, and assemble them into a summary report.

2.2 Information Collected

To provide the appropriate basis for comparisons of costs and practices, the project team gathered three types of information from each of the comparator companies, as shown in Figure 2 below. Demographics were used in analyzing the results, and for assuring that there was an appropriate peer group. Operational practice information helped in understanding replacement rates and approaches for replacing wood poles. Cost information was used for the final cost comparisons. The majority of the data was from 2019 Year End.

Figure 2 -- Information Gathered from Hydro One and the Comparator Group

Demographic Information

- Number of overhead transmission circuit km and structure km
- Number of transmission circuits
- Number of transmission wood poles and structures
- Age of poles and structures

Practice Information

- Expected Service Life for transmission wood poles
- Poles and structures replaced in the past 5 years
- Plans for replacement over the next 5 years
- Contracting approaches for pole replacements
- Use of live-line work while replacing poles

Cost Performance Data

- Unit costs for wood pole and wood structure replacement
- Components included in the costs for pole replacement

2.3 Comparator Group Selection

In any benchmarking study, the goal is to assemble a comparator group that is representative of the industry, so that both demographic similarities and differences can be accommodated and that different operating practices are likely to be identified for analysis. To achieve a representative panel of comparators, Guidehouse and First Quartile defined characteristics for evaluating and selecting comparators who would be appropriate for comparison against Hydro One, including size (e.g. number of wood poles, km of line, circuits) and asset age.

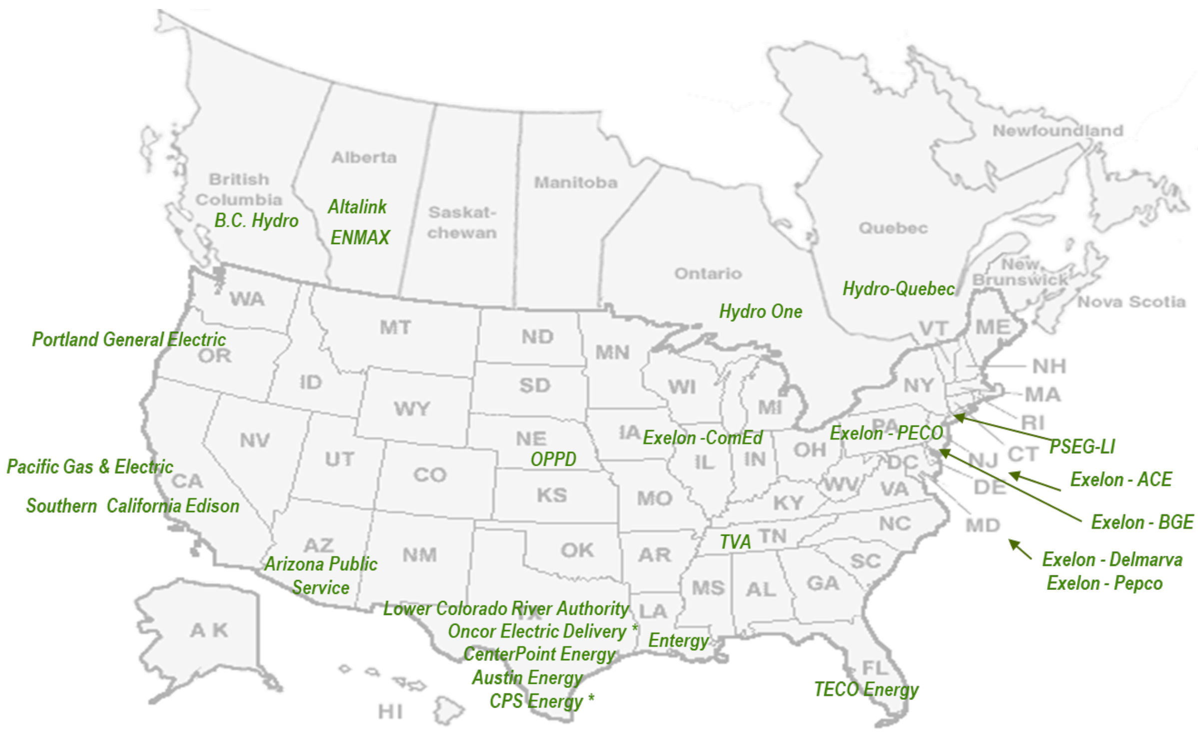
The next step in comparator selection involved recruiting utilities to participate. This started with the utilities already involved in the annual First Quartile benchmarking study. The group was expanded by approaching a number of other Canadian and U.S. utilities who met the basic demographic criteria of large size along with geographic spread across North America. In all, 32 utilities were approached and invited to participate, including 7 in Canada and 25 in the U.S.

A total of 25 utilities responded in full or in part to the data request. Those not responding cited various reasons for not participating:

- Lack of sufficient data
- Insufficient resources
- Competing priorities

Figure 3 below shows the utilities represented in the comparison panel. As can be seen, there is a mix of U.S. and Canadian utilities, mostly large utilities, with a few smaller ones. They represent the industry from the standpoint of experiencing various weather patterns, having both low-density and higher-density portions of service territory, and having both similar and different regulatory circumstances from Hydro One.

Figure 3 – Utilities in the Comparator Group !



In aggregate, the comparator group provides a fair representation of the North American transmission utility industry, so that HONI's performance can be understood in the context of the industry.

2.4 Normalizing Factors

Data from the comparator group is normalized according to variables that enable comparisons among utilities that do not have identical characteristics. Necessary normalizations include currency exchange (results herein are shown in Canadian dollars) and normalizing by the number of poles replaced (e.g. cost per wood pole) to understand the relative cost performance of HONI.

Additional variables considered for normalizing the resulting costs included company size, density, and percentage of poles replaced over the past five years. None of these proved to have statistically significant predictive value within the comparison panel, so only the two described above (currency and number of poles replaced) were used in the analysis.

3 Benchmarking Observations

This section of the report summarizes the primary findings of the study, in the form of a series of observations. These are broken into three sub-sections – (3.1) work practices for wood pole replacements, (3.2) replacement unit costs, and (3.3) wood pole replacements, including age, expected service life, and replacement rates. In the graphs that follow, Hydro One is identified with a red arrow for ease of identification. The values for Q1, Q2, and Q3 are the values that are 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.

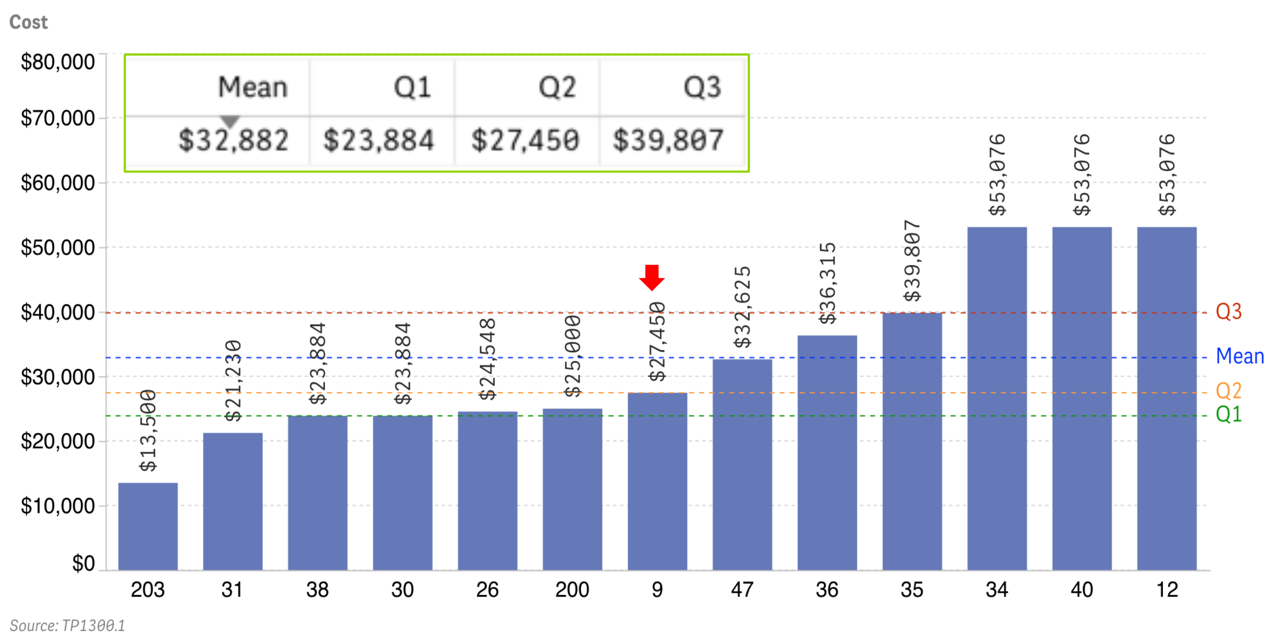
3.1 Work Practices

The study investigated, at a high level, some of the practices utilized in conducting wood pole replacements, including pole replacement selection process (mostly through periodic inspections) and evaluation of associated equipment (e.g., crossarms, insulators, and hardware) that may warrant replacement in conjunction with the wood poles. HONI's approach to these practices was in line with the practices in the comparator group.

3.2 Replacement Unit Costs

HONI's transmission wood structure replacement costs are $27,450 per pole, well below the mean of $32,882 for the comparator group as shown in Figure 4 below.

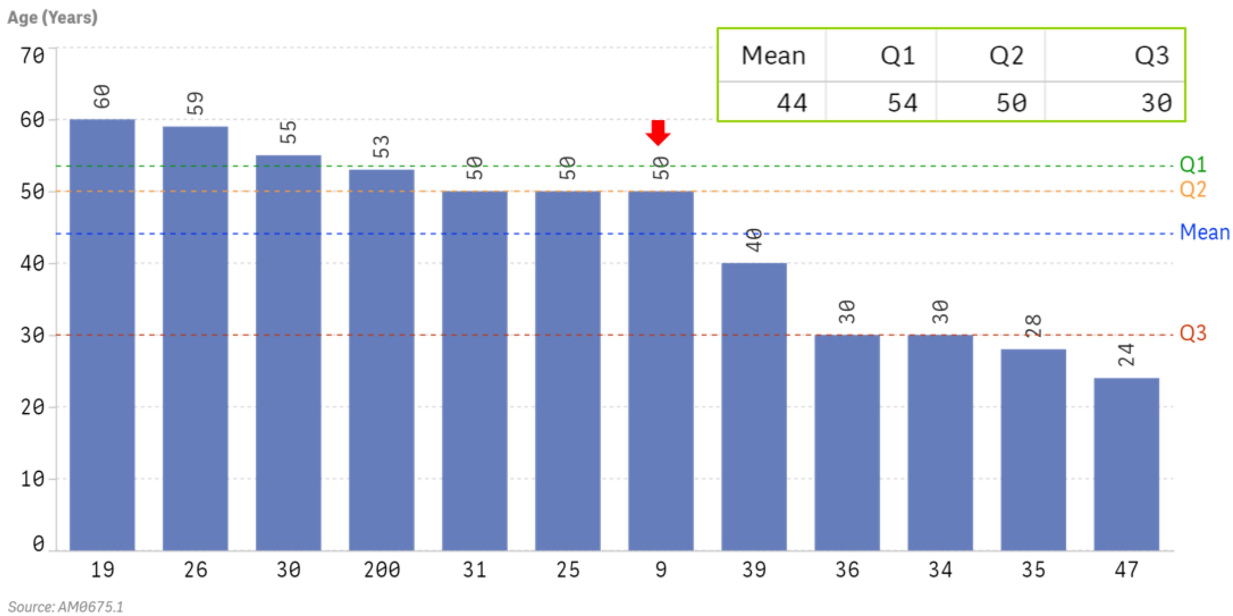
Figure 4 -- Unit Cost for Single Pole Wood Replacement



3.3 Wood Pole Replacements

Each of the participating companies was asked about the expected longevity of its transmission wood poles. The responses implicitly reflect past experience, local weather and other in-field hazards, risk tolerance, and asset depreciation. The net result for each company is an expected service life for its poles, which provides a basis for comparing the age of in-service wood poles and replacement rates for those same wood poles. Figure 5 shows the expected service life for the responding companies. HONI expects a wood pole service life of 50 years, which is above the mean of the peer group of 44 years, but at the median value of the group.

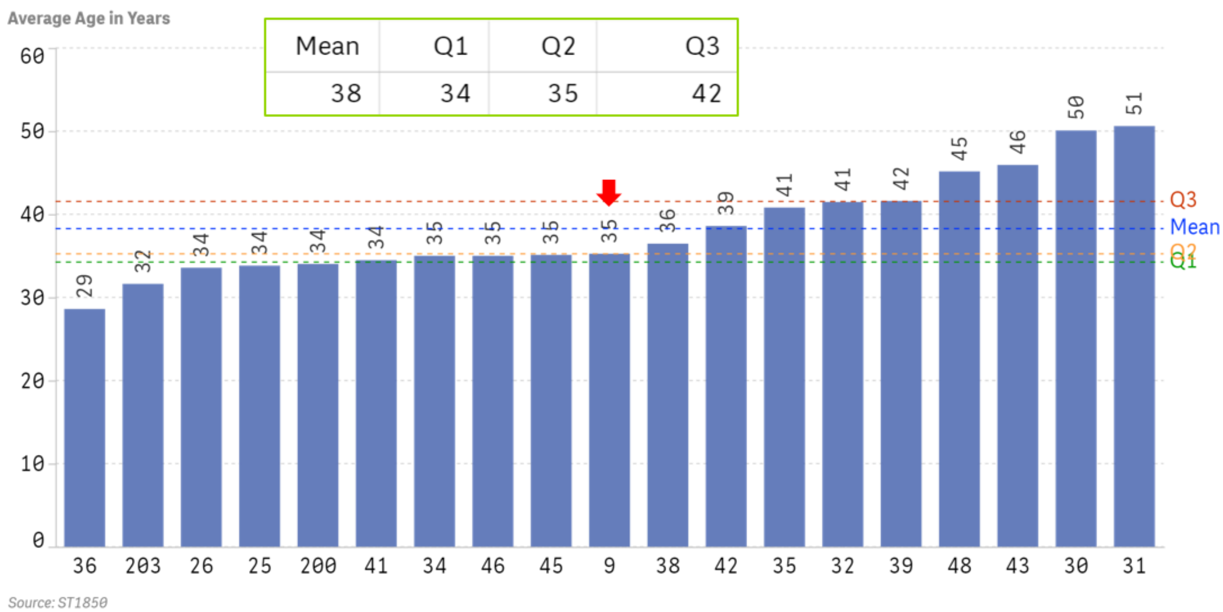
Figure 5 – Expected Service Life for Transmission Wood Poles



Mean	Q1	Q2	Q3
44	54	50	30

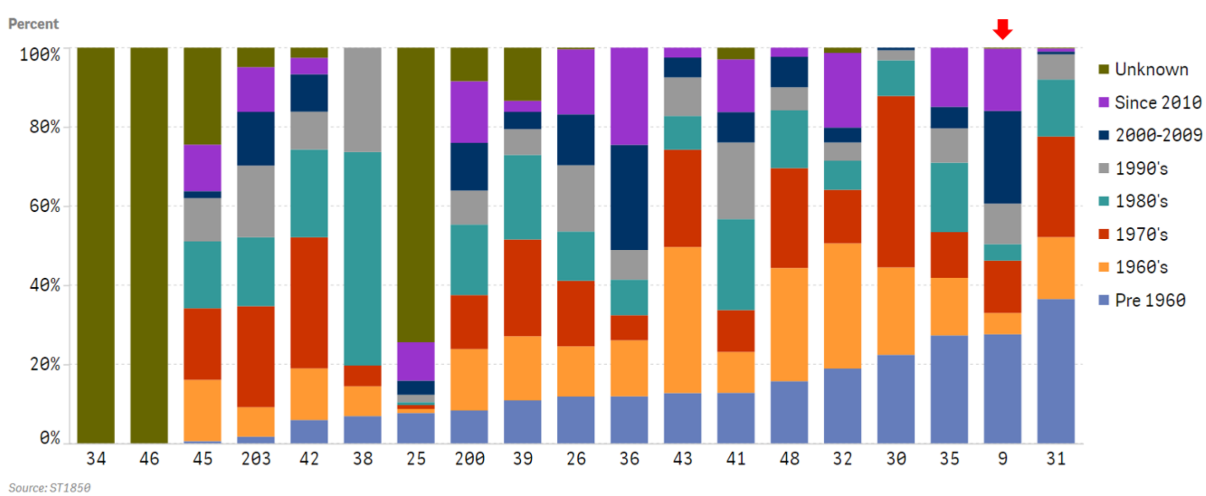
The average age of Hydro One's transmission wood structures (35 years) is similar to the average age of the comparator group (38 years), as shown in Figure 6 below.

Figure 6 – Average Age of Transmission Wood Structures



In evaluating the age of poles, the mean of the population (average age) is a good starting point, but not fully indicative of the age of the pole fleet. To better understand the age of the wood pole fleet, it is helpful to assess the distribution of the age of the poles as well as the average. Figure 7 shows the distribution of transmission wood poles installed by decade for each of the participating utilities. As can be seen from the figure, HONI has the second largest percentage of wood poles installed pre-1960's. Thus, while HONI's average wood pole age is 35 years as described above, it is due to the high percentage of younger poles that are under 20 years old that offset the high percentage of older poles that are over 60 years old.

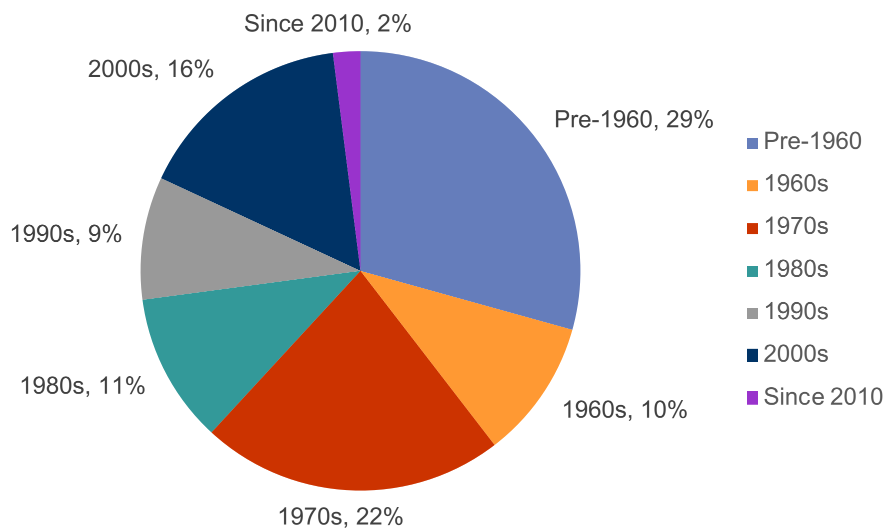
Figure 7 -- Percent of In-Service Transmission System Wood Poles Installed by Decade



Hydro One relies on its condition-based field inspections to identify transmission wood poles that are in an end-of-life condition. Figure 8 below shows the breakdown by age of HONI's wood poles that have been determined by inspection to be at end-of-life.[1] Of these poor condition transmission wood poles, a high percentage of those structures (29%) 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. HONI's end-of-life data shown in the figure below illustrates the prevalence of poor condition poles in the older portion of the wood pole population.

Figure 8 -- Percent of End-of-Life Wood Structures by Decade (HONI)



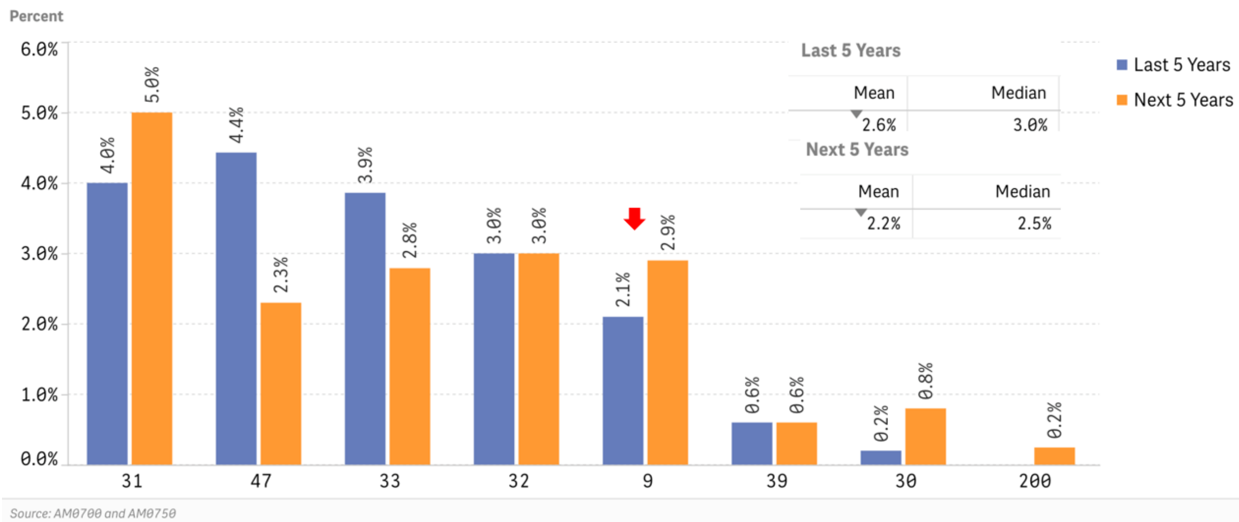
[1] Data provided by Hydro One – comparable data were not gathered from the comparator companies.

Participating utilities were surveyed on the number of wood poles that they have replaced over the past five years, and how many they expect to replace over the next five years. The resulting numbers for each company, measured in terms of the percentage of poles replaced or expected to be replaced on an annual basis during this 10-year period, is shown in Figure 9 below.

HONI replaced an average of 2.1% of its wood poles annually during the last five years, versus the mean of 2.6% for the comparator utilities. HONI is expecting to replace 2.9% of its poles annually over the next five years compared to the mean of 2.2% for the comparator utilities.

As noted above, HONI has the second largest percentage of wood poles installed pre-1960's and a correspondingly large number of pre-1960 wood poles identified for replacement due to poor condition. Similarly the large number of poles from the 2000's that are at end-of life creates a need for additional replacements. Considering these factors a marginally higher replacement rate is expected.

Figure 9 -- Percent of Transmission Wood Structures Replaced and Expected to Be Replaced Annually !



ELECTRIC POWER
RESEARCH INSTITUTE

Power Transformer Condition Assessment (2021) – Project ID: 1-11484

Power Transformer Expert System (PTX) Analysis of Hydro One Transformers

CONTENTS

LIST OF TABLES

Introduction

This report describes an analysis of 208 of Hydro One Networks Inc.'s (Hydro One) power transformers (each single phase unit is counted as one transformer) using EPRI's Power Transformer Expert System (PTX) software to assess the main tank condition. Hydro One provided description and historical oil test[1] data for these power transformers.

Background

The PTX Transformer Fleet Management software[2] utilizes a Rule-Based MYCIN Expert System to assess the condition of a fleet of transformers using readily available condition and transformer description (nameplate) data. The result is a series of indices for each transformer that provide insight into the condition of the paper (cellulose) insulation system[3] and the potential for any abnormal incipient fault. These indices can be used to guide further diagnostic testing and maintenance actions for specific units, as well as guide overall fleet management and replacement decisions. Each index represents a different aspect of power transformer condition. A poor condition in any one of these aspects poses a risk of failure and may necessitate replacement.

The approach that the PTX software takes is intended to meet the following three objectives:

- Uses available information
- Incorporates advanced analytical capabilities
- Provides decision support for multiple stakeholders

The PTX software produces a set of main tank condition indices, as follows:

- Normal Degradation Index

  This index is intended to provide an indication of the physical condition of the paper (cellulose) insulation system relative to its initial state. Transformers undergo normal aging or degradation due to operation of the transformer under conditions that do not exceed the design criteria of the transformer. This normal degradation is generally due to aging of the paper insulation system, in which the paper insulation experiences decreasing mechanical strength as a function of time and temperature. This reduced mechanical strength poses a risk of dielectric failure when the insulation is disturbed

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[1] Power transformers are immersed in oil. Since the insulating oil is in contact with a majority of the components of a power transformer and can be readily sampled, compounds dissolved in the oil can be measured to provide diagnostic insights into the condition of components of the power transformer that cannot be easily sampled or inspected while in service.

[2] The PTX development effort began in 2007 with a concept that involved multiple stakeholders and the analysis of readily available data from large transformer fleets. PTX Version 6, released in 2019, has been tested with data from some 32,000 transformers from 22 utility fleets—a total of 400,000-plus test data points. This work is documented in the EPRI technical update report Analytics Assessment and Comparisons. EPRI, Palo Alto, CA: 2020. 3002019254.

[3] The condition of the cellulose insulation system is of particular concern as the cellulose insulation is not replaceable and thermal degradation of the cellulose is irreversible, whereas the liquid insulation (oil) can be processed, reclaimed, or replaced.

mechanically (such as during through-fault events). A Normal Degradation Index value above 0.25 warrants consideration for replacement.

- Abnormal Degradation Indices

  Abnormal Condition Indices are divided into three categories: Thermal, Electrical, and Core. These indices are used to identify units that may be experiencing a variety of unexpected problems due to manufacturing or operating issues or defects. Transformers in these categories show evidence of the existence of some incipient fault condition that would not be present or expected in normal operation.

  Note that due to the non-specific nature of field diagnostic tests, a single defect may provide indications in more than one category. An Abnormal Condition Index value above 0.5 in any category warrants consideration for replacement.

PTX Analysis of Hydro One Transformers

Hydro One provided description data for 208 power transformers (each single phase unit is counted as one transformer) that it deems to be in poor condition. Description data for the 208 transformers consisted of:

- Voltage ratings
- MVA ratings
- Type (Auto, Step-down, Regulator, etc.)
- Number of phases (Inferred as 3-phase, unless phase noted)
- Manufacturer
- Year Built
- In-service Year

In addition to the description data, oil test histories (main tank oil only) – consisting of Dissolved Gas Analysis (DGA), oil quality, and Furan Test data – were provided. The oil test histories generally spanned from 2011 to 2020 and consisted of typically 8-10 samples per transformer (roughly annually). Furan data was available in most oil test records.

The provided data was analyzed using EPRI's PTX. This analysis examined the condition of the main tank components only (active part).

Hydro One evaluates transformer condition based on the following criteria:

1. Main tank oil test results - DGA, oil quality and furan test results.
2. Factors other than main tank oil test results - Load Tap Changers (LTC) DGA, oil leaks, LTC issues, cooling system issues, etc.

EPRI's analytical results confirm degradation in the main tank for 155 transformers (each single phase unit is counted as one transformer) (consistent with Hydro One's criteria 1 above) and deem them to be in deteriorated condition (see Table 1). 17 transformers based on PTX analysis were deemed to be in marginal condition (see Table 2). The remaining 36 transformers were not deemed to be in poor or marginal condition by PTX based on the main tank data provided and were likely deemed in poor condition by Hydro One based on factors other than the main tank oil test results (consistent with Hydro One's criteria 2 above) (see Table 3).

A

DETAILED PTX ANALYSIS RESULTS

Table 1

Transformers deemed in poor condition by Hydro One and confirmed by PTX analysis

A transformer with a Normal Degradation Index >= 0.25 or an Abnormal Index >= 0.5 is deemed a candidate for replacement.

Station	Designation	Vintage	Winding Voltages (kV)	Top MVA	Normal Degradation	Abnormal Thermal	Abnormal Electrical	Abnormal Core
PRESTONTS	T4	1971	220/28/28	125	1	0.1	0	0
GAGETS	T4	1949	110/14.2	56	1	0.1	0	0
GLENDALETS	T4	1952	110	15	1	0.1	0	0
GAGETS	T6	1942	110/14.2	56	1	0.1	0	0
GAGETS	T5	1948	110/14.2	56	1	0.1	0	0
MAINTS	T3	1968	110/14.2/14.2	75	1	0.1	0	0
MANBYTS	T14	1968	220/28	93.3	1	0.33	0.47	0.29
FAIRBANKTS	T2	1960	110/28.4	83.3	1	0.1	0	0
ARNPRIORTS	T2	1957	110/44/4	41.6	0.99	0.1	0	0
SLATERTS	T3	1968	110/14.2/14.2	75	0.97	0.3	0.1	0.08
KINGSVILTS	T1	1960	110/28.4	41.7	0.97	0.1	0	0
WILSONTS	T1	1968	220/44	125	0.97	0.43	0.71	0.49
MANBYTS	T13	1968	220/28	83.3	0.93	0.43	0.7	0.48
FAIRBANKTS	T1	1960	110/28.4	83.3	0.93	0.1	0	0
DOBBINTS	T5	1953	228.8/116.9/12.8	115	0.93	0.1	0	0
OTTOHLDNTS	T3	1951	230/115/13.2	20	0.93	0.1	0	0
FAIRBANKTS	T3	1960	110/28.4	83.3	0.93	0.14	0.24	0.16
ESSATS	T1	1955	228.8/116.9/12.7	115	0.89	0.1	0	0
BARRIETS	T1	1962	110/44/4	91.6	0.86	0.24	0.42	0.28
GLENDALETS	T3	1952	110	15	0.86	0.1	0	0
FAIRBANKTS	T4	1960	110/28.4	83.3	0.82	0.17	0.29	0.2
PORTHOPETS	T4	1959	110/44/4	83.3	0.82	0.1	0	0
OTTOHLDNTS	T3	1952	230/115/13.2	20	0.81	0.1	0	0
BARRIETS	T2	1962	110/44/4	91.6	0.77	0.44	0.74	0.52
KEITHTS	T11	1953	228.8/116.9/12.75	104	0.76	0.1	0	0
RUNNYMEDTS	T4	1962	110/28.4	93.3	0.76	0.28	0.81	0.15
HANLONTS	T1	1956	110/14.2	33.3	0.76	0.1	0	0
BERMNDSYTS	T3	1965	210/28/28	140	0.72	0.41	0.67	0.45
BELLEVILTS	T2	1968	220/44	125	0.72	0.35	0.53	0.32
HAVELOCKTS	T1	1964	235/44	83.3	0.69	0.45	0.76	0.52
CATARAQUTS	T1	1968	236.8/121/13.4	250	0.69	0.1	0	0
SLATERTS	T2	1968	110/14.2/14.2	75	0.66	0.5	0.62	0.57
BUCHANANTS	T3	1968	236.8/121/13.4	250	0.66	0.1	0	0
CHARLESTS	T3	1967	110/14.2/14.2	75	0.63	0.43	0.72	0.49
MACKENZITS	T3	1972	232/14.1	125	0.63	0.1	0.04	0.03
OTTOHLDNTS	T3	1952	230/115/13.2	20	0.62	0.1	0	0
BECK2TS	R27	1961	230/230/18.1	400	0.62	0.28	0	0
FAIRCHLDTS	T1	1970	220/28/28	125	0.61	0.1	0	0
PORTHOPETS	T3	1959	110/44/4	83.3	0.59	0.23	0.35	0.22
CHARLESTS	T4	1967	110/14.2/14.2	75	0.58	0.44	0.75	0.51
SCARBOROTS	T23	1974	220/28/28	125	0.57	0.67	0.82	0.74
WAUBASHNTS	T5	1973	215.5/44	83.3	0.57	0.1	0	0
KEITHTS	T12	1954	228.8/116.9/12.7	115	0.57	0.1	0	0
MIDDLPRTTS	T3	1972	500/240/28	250	0.57	0.1	0	0
OTTOHLDNTS	T4	1954	230/115/13	20	0.56	0.1	0	0
BRIDGMANTS	T12	1957	110/14.2/14.2	66.7	0.55	0.1	0	0
SEAFORTHTS	T5	1959	236.8/121/13.4	250	0.54	0.1	0	0
ELLIOTLKTS	T2	1950	110/44/4.16	19	0.53	0.1	0	0
OTTOHLDNTS	T4	1954	230/115/13	20	0.53	0.1	0	0
NEPEANTS	T4	1974	215.5/44	125	0.53	0.38	0.59	0.39
RUNNYMEDTS	T3	1962	110/28.4	93.3	0.52	0.44	0.73	0.5
STRACHANTS	T15	1981	110/14.2/14.2	75	0.52	0	0	0
MARTINDLTS	T26	1970	215.5/44/13	125	0.52	0.1	0.14	0.1
LAUZONTS	T7	1972	215.5/28	83.3	0.52	0.42	0.7	0.48
BELLEVILTS	T1	1978	215.5/44	125	0.51	0.38	0.75	0.51
BATHURSTTS	T3	1970	220/28/28	125	0.51	0.38	0.6	0.39
LORNEPRKTS	T2	1974	215.5/28/28	125	0.51	0.1	0	0
LAUZONTS	T1	1968	236.8/121/13.4	250	0.51	0.1	0	0
LAUZONTS	T2	1968	236.8/121/13.4	250	0.5	0.1	0	0
HANMERTS	T9	1972	500/240/28	250	0.5	0.1	0	0
KENORATS	T1	1972	232/14.1	125	0.49	0.1	0	0
STRACHANTS	T13	1982	110/14.2/14.2	75	0.49	0	0	0
PORTCOLBTS	T61	1964	110/28.4	46.7	0.48	0.1	0	0
LAKETS	T1	1972	216/28	83.3	0.48	0.1	0.02	0.01
GAGETS	T3	1946	110/14.2	56	0.48	0.1	0	0
CLARKETS	T3	1969	220/28	83.3	0.48	0.43	0.73	0.5

Station	Designation	Vintage	Winding Voltages (kV)	Top MVA	Normal Degradation	Abnormal Thermal	Abnormal Electrical	Abnormal Core
LAUZONTS	T6	1970	220/28	83.3	0.47	0.44	0.75	0.52
MURRAYTS	T11	1974	110/14.2/14.2	75	0.47	0.1	0	0
HANOVERTS	T2	1960	110/44/4	83.3	0.46	0.1	0	0
LAMBTONTS	T6	1968	220/28	93.2	0.46	0.42	0.7	0.47
JOHNTS	T5	1977	110/14.2/14.2	125	0.45	0	0	0
BERMNDSYTS	T4	1965	210/28/28	125	0.45	0.42	0.7	0.48
WOODBRDGTS	T5	1973	215.5/44/28	125	0.45	0.44	0.74	0.5
FAIRCHLDTS	T4	1983	215.5/28/28	125	0.44	0.3	0.57	0.38
BRUCEATS	T25	1981	500/240/28	750	0.44	0	0	0
MIDDLPRTTS	T3	1972	500/240/28	250	0.44	0.1	0	0
MOOSELAKTS	T3	1950	110/44/4.16	15	0.43	0.1	0	0
BASINTS	T3	1981	110/14.2/14.2	75	0.43	0	0	0
BRUCEATS	T28	1977	500/240/28	750	0.42	0	0	0
MANBYTS	T7	1968	236.8/121/13.4	250	0.42	0.1	0	0
LENNOXTS	T51	1974	500/240/28	750	0.42	0.1	0	0
BILBERRYTS	T2	1961	110/28.4	83.3	0.41	0.47	0.58	0.53
ESSATS	T3	1974	500/240/28	250	0.41	0.1	0	0
BRAMALEATS	T4	1970	215.5/44	83.3	0.41	0.29	0.5	0.34
MIDDLPRTTS	T3	1972	500/240/28	250	0.41	0.1	0	0
ALLISTONTS	T3	1970	215.5/44/0		0.41	0.15	0.04	0
DUPLEXTS	T2	1968	110/14.2/14.2	75	0.4	0.43	0.72	0.49
SEAFORTHTS	T2	1960	110/28.4	41.7	0.4	0.1	0	0
CATARAQUTS	T2	1968	236.8/121/13.4	250	0.4	0.1	0	0
BEACHTS	T8	1965	236.8/121/13.4	268.8	0.4	0.1	0	0
BEACHTS	T7	1965	236.8/121/13.4	268.8	0.4	0.1	0	0
BRUCEATS	T27	1977	500/240/28	750	0.39	0	0	0
BRIDGMANTS	T13	1957	110/14.2/14.2	66.7	0.39	0.12	0.2	0.13
DUPLEXTS	T3	1974	110/14.2/14.2	75	0.39	0.1	0	0
BRAMALEATS	T3	1970	215.5/44	83.3	0.39	0.43	0.72	0.5
HANMERTS	T9	1972	500/240/28	250	0.39	0.1	0	0
TERAULEYTS	T4	1977	110/14.2/14.2	125	0.39	0	0	0
DETWEILRTS	T4	1963	236.8/121/13.4	225	0.38	0.1	0	0
BRIDGMANTS	T11	1958	110/14.2/14.2	66.7	0.38	0.1	0	0
WILSONTS	T2	1970	215.5/44/13	125	0.38	0.22	0.21	0.08
MOOSELAKTS	T2	1951	110/44/4.16	8	0.38	0.1	0	0
ARNPRIORTS	T1	1960	110/44/4	41.67	0.38	0.1	0	0
BEACHTS	T1	1973	236.8/121/13.4	250	0.38	0.1	0	0
ORANGEVLTS	T2	1965	210/44/28	125	0.37	0.45	0.75	0.52
TERAULEYTS	T3	1976	110/14.2/14.2	125	0.37	0	0	0
STANDREWTS	T3	1964	110/28.4	93.3	0.36	0.41	0.66	0.44
MANBYTS	T12	1971	236.8/121/13.4	250	0.36	0.1	0	0
LAMBTON2TS	T7	1968	346/225/22	600	0.35	0.26	0.41	0.27
ORANGEVLTS	T4	1969	220/44	83.3	0.35	0.1	0.08	0.01
HANLONTS	T2	1956	110/14.2	33.3	0.34	0.1	0	0
WAUBASHNTS	T6	1973	215.5/44	83.3	0.34	0.1	0	0
DUPLEXTS	T1	1968	110/14.2/14.2	75	0.33	0.44	0.73	0.5
REXDALETS	T2	1988	215.5/28/28	125	0.33	0	0	0
ESPLANADTS	T12	1987	110/14.2/14.2	100	0.33	0	0	0
LAUZONTS	T8	1979	215.5/28	83.3	0.32	0.02	0.04	0.03
ALBIONTS	T2	1971	225/14/14	75	0.32	0.44	0.74	0.51
GLENDALETS	T1	1968	115.5/14.2/14.2	75	0.31	0.1	0	0
BRACEBRGTS	T1	1973	215.5/44	83.3	0.31	0.1	0	0
SEAFORTHTS	T1	1960	110/28.4	41.7	0.31	0.1	0	0
MANBYTS	T9	1971	??		0.31	0.1	0	0
LAKETS	T3	1982	215.5/14/14	75	0.31	0	0	0
MALVERNTS	T3	1982	215.5/28/28	125	0.31	0	0	0
HAVELOCKTS	T2	1964	235/44	83.3	0.3	0.44	0.76	0.51
LAUZONTS	T5	1970	220/28	83.3	0.3	0.44	0.74	0.51
OWENSNDTS	T4	1979	215.5/44	125	0.3	0.12	0.25	0.16
DUPLEXTS	T4	1974	110/14.2/14.2	75	0.3	0.1	0	0
JOHNTS	T3	1985	110/14.2/14.2	75	0.3	0	0	0
STRACHANTS	T14	1972	110/14.2/14.2	75	0.29	0.1	0.01	0
ALLISTONTS	T4	1970	215.5/44/0	83.3	0.28	0.77	0.94	0.87
ORILLIATS	T2	1977	215.5/44	125	0.27	0.38	0.75	0.52
ESSATS	T3	1974	500/240/28	250	0.27	0.1	0	0
CLAIREVLTS	T13	1980	500/240/28	750	0.26	0	0	0
LONGUEILTS	T4	1965	235/44	93.3	0.25	0.21	0.19	0.11
PALERMOTS	T3	1970	220/28	83.3	0.25	0.1	0.04	0.03
TERAULEYTS	T2	1976	110/14.2/14.2	125	0.25	0	0	0
FAIRCHLDTS	T3	1983	215.5/28/28	125	0.23	0.28	0.53	0.34
CARLAWTS	T1	1974	110/14.2/14.2	75	0.22	0.43	0.71	0.48
STANDREWTS	T4	1964	110/28.4	93.3	0.22	0.44	0.74	0.51
TALBOTTS	T3	1983	215.5/28/28	125	0.21	0.31	0.6	0.4
CLARKETS	T4	1972	220/28	83.3	0.2	0.44	0.74	0.51
WINGHAMTS	T2	1965	235/44/12.4	83.3	0.2	0.55	0.8	0.34
BEACHTS	T6	1976	215.5/14/14	75	0.19	0.32	0.63	0.44
LAMBTONTS	T5	1968	220/28	93.2	0.16	0.44	0.73	0.5
ORANGEVLTS	T1	1965	210/44/28	125	0.16	0.44	0.74	0.51
STRATFRDTS	T1	1970	220/28	83.3	0.15	0.4	0.65	0.44
PARRYSNDTS	T1	1970	220/44	41.67	0.13	0.44	0.75	0.51
WALLACETS	T4	1969	220/44	41.67	0.13	0.46	0.78	0.54

Station	Designation	Vintage	Winding Voltages (kV)	Top MVA	Normal Degradation	Abnormal Thermal	Abnormal Electrical	Abnormal Core
WILSONTS	T4	1975	215.5/44/13	125	0.12	0.36	0.69	0.48
CALEDNIATS	T2	1973	215.5/28	83.3	0.1	0.43	0.71	0.49
WALLACETS	T3	1970	220/44	41.7	0.09	0.46	0.78	0.54
BILBERRYTS	T1	1961	110/28.4	83.3	0.09	0.46	0.58	0.46
WILSONTS	T3	1975	215.5/44/13	125	0.07	0.29	0.55	0.37
BEACHTS	T5	1976	215.5/14/14	75	0.07	0.33	0.63	0.43
TIMMINSTS	T2	1972	216/28	83.3	0.02	0.45	0.76	0.53
WINGHAMTS	T1	1965	235/44/12.4	83.3	0	0.44	0.75	0.52

Table 2

Transformers deemed in poor condition by Hydro One and deemed in marginal condition by PTX

A transformer with a Normal Degradation Index >=0.2 and <0.25 or an Abnormal Index >= 0.3 and <0.5 is deemed marginal.

Station	Designation	Vintage	Winding Voltages (kV)	Top MVA	Normal Degradation	Abnormal Thermal	Abnormal Electrical	Abnormal Core
RUSSELLTS	T2	1973	110/14.2/14.2	75	0.24	0.1	0	0
LISGARTS	T1	1973	110/14.2/14.2	75	0.24	0.1	0	0
AGINCORTTS	T5	1979	215.5/28/28	125	0.24	0	0	0
ELLIOTLKTS	T1	1957	110/44/4	41.6	0.23	0.1	0	0
LAKETS	T4	1983	215.5/14/14	75	0.23	0	0	0
WAWATS	T1	1970	226/121/14.1	125	0.23	0.1	0	0
PICTONTS	T2	1960	230/46	83.3	0.23	0.1	0	0
HANMERTS	T9	1972	500/240/28	250	0.23	0.1	0	0
LESLIETS	T1	1963	210/28/14.2	125	0.22	0.1	0.02	0
BUCHANANTS	T2	1978	236.8/121/13.4	250	0.22	0	0	0
PRESTONTS	T3	1971	220/28/28	125	0.21	0.1	0	0
NEPEANTS	T3	1978	215.5/44	125	0.21	0.2	0.39	0.27
ALGOMATS	T6	1948	228.8/116.9/12.7	115	0.21	0.1	0	0
KENTTS	T2	1975	215.5/28/28	125	0.2	0	0	0
LINCLNHTTS	T1	1980	110/14.2/14.2	75	0.2	0	0	0
TALBOTTS	T4	1979	215.5/28/28	125	0.2	0.11	0.23	0.13
BASINTS	T5	1981	110/14.2/14.2	75	0.2	0	0	0

Table 3

Transformers deemed in poor condition by Hydro One and not deemed in poor condition by PTX

Station	Designation	Vintage	Winding Voltages (kV)	Top MVA	Normal Degradation	Abnormal Thermal	Abnormal Electrical	Abnormal Core
MIDHURSTTS	T4	1978	215.5/44	125	0.19	0.07	0.11	0.05
DETWEILRTS	T2	1959	236.8/121/13.4	250	0.19	0.1	0	0
PORCUPINTS	T3	1969	??		0.18	0.1	0	0
NEBOTS	T3	1971	225/14/14	75	0.18	0.1	0.06	0.04
OWENSNDTS	T5	1974	236.8/121/13.4	250	0.18	0.1	0	0
PORCUPINTS	T8	1967	480/230/28.2	360	0.17	0.1	0	0
LAMBTON2TS	T8	1973	346/225/22	600	0.17	0.1	0	0
PALERMOTS	T4	1973	220/28	83.3	0.17	0.1	0.08	0
SEAFORTHTS	T6	1969	236.8/121/13.4	250	0.17	0.1	0	0
GAGETS	T8	1966	110/14.2/14.2	120	0.15	0.1	0	0
MIDDLPRTTS	T6	1977	500/240/28	750	0.15	0	0	0
OTTOHLDNTS	T4	1954	230/115/13	20	0.15	0.1	0	0
PORTCOLBTS	T62	1964	110/28.4	46.7	0.15	0.1	0	0
STLAWRENTS	PS33	1962	240/240	300	0.15	0.1	0	0
DOBBINTS	T1	1968	236.8/121/13.4	250	0.14	0.1	0	0
THOROLDTS	T1	1971	110/14.2/14.2	75	0.13	0.1	0	0
LINCLNHTTS	T2	1974	110/14.2/14.2	75	0.13	0.1	0	0
PICTONTS	T1	1960	230/46	83.3	0.12	0.1	0	0
TERAULEYTS	T1	1976	110/14.2/14.2	125	0.11	0	0	0
BIRMNGHMTS	T1	1974	110/14.2/14.2	75	0.1	0.1	0	0
GARDINERTS	T1	1974	215.5/44	125	0.09	0.1	0.05	0.03
MURRAYTS	T14	1973	110/14.2/14.2	75	0.07	0.1	0	0
ESSATS	T3	1974	500/240/28	250	0.06	0.1	0	0
NEBOTS	T4	1971	225/14/14	75	0.05	0.1	0.07	0.05
PORCUPINTS	T4	1969	??		0.05	0.1	0	0
RUSSELLTS	T1	1977	110/14.2/14.2	75	0.05	0	0	0
LONGUEILTS	T3	1965	235/44	93.3	0.04	0.24	0.29	0.27
CARLAWTS	T2	1975	110/14.2/14.2	75	0.04	0	0	0
ORANGEVLTS	T3	1969	220/44	83.3	0.03	0.1	0.04	0.03
SARNSCOTTS	T5	1976	236.8/121/13.4	250	0.03	0	0	0
STLAWRENTS	R33	1958	230/230/12.7	300	0.03	0.1	0	0
JOHNTS	T6	1978	110/14.2/14.2	125	0.02	0	0	0
NANTICOKTS	T11	1974	500/240/28	750	0.01	0.1	0	0
GAGETS	T9	1965	110/14.2/14.2	120	0	0.1	0	0.01
BRIDGMANTS	T14	1972	110/14.2/14.2	75	0	0.1	0	0
STLAWRENTS	PSR34	1978	240/240	300	0	0	0	0

Hydro One Transmission Line Loss Review Report

July 13, 2021

Prepared for:

Hydro One

Prepared by:

Stantec Consulting Ltd.

Sign-off Sheet

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Prepared by Ashraf Ul Haque Digitally signed by Ashraf Ul Haque Date: 2021.07.14 09:41:10 -06'00' Bhuiya, Ashikur Digitally signed by Bhuiya, Ashikur Date: 2021.07.14 10:51:33 -06'00'

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Dr. Ashikur Bhuiya, PEng

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Executive Summary

Stantec has carried out a review of Hydro One's transmission line loss processes with a view to assess the principles and completeness of such processes and identify potential opportunities to cost-effectively reduce transmission line losses.

Stantec reviewed Hydro One's *Transmission Line Loss Guideline – R0* ("Transmission Line Loss Guideline" or "Guideline", attached as Appendix A) as well as the following reports regarding industry practices related to line loss:

- National Grid, *National Grid's Strategy Paper to address Transmission Licence Special Condition 2K: Electricity Transmission Losses*, September 2014 ("National Grid Strategy Paper").
- Council of European Energy Regulators ("CEER"), *CEER Report on Power Losses, Ref: C17-EQS-80-03*, October 18, 2017 ("CEER 2017 Report").
- CEER, *2nd CEER Report on Power Losses, Ref: C19-EQS-101-03,* March 23, 2020 ("CEER 2020 Report").

Stantec found that Hydro One's line loss practices are generally aligned with the recommendations outlined in the above reports in relation to transmitters or transmission facility owners.

Stantec also reviewed the Electric Power Research Institute's ("EPRI") *Hydro One Transmission Losses 3002012721 - Technical Report* dated March 2018 ("EPRI Hydro One Transmission Losses Report"), which investigated industry best practices for transmission line loss mitigation as a basis for comparing Hydro One's relevant practices. Based on its review, Stantec concurs with EPRI's findings and the conclusion that Hydro One's design practices are generally consistent with industry best practices for loss mitigation.

Stantec found that Hydro One's Transmission Line Loss Guideline, which outlines certain screening steps and detailed steps for planners' evaluation of investment alternatives based on the cost of line losses, provides clarity and efficiency for the purposes of evaluating the optimal alternative. The Transmission Line Loss Guideline provides a reasonable approach in determining the cost impact of line loss and supports planning decisions for customer connections, system reinforcement, system facility refurbishment and local area supply investments.

Based on the scope and findings of this review, Stantec concluded that Hydro One follows industry best practices with respect to transmission line loss management.

Recommendations

Stantec provides the following recommendations to Hydro One with respect to transmission line loss management:

1. Ensure implementation and consistent use of the Transmission Line Loss Guideline for new investments that impact transmission line losses.
2. Track the number of projects that have been assessed for transmission line loss mitigation and the associated MW reduction in losses as documented in approved business cases.

Abbreviations

CEER	Council of European Energy Regulators
EPRI	Electric Power Research Institute
HVDC	High Voltage Direct Current
IESO	Independent Electricity System Operator
OEB	Ontario Energy Board
WLV	Whole Life Value

1.0 INTRODUCTION

The Ontario Energy Board (OEB) in its EB-2019-0082 Decision and Order directed Hydro One to "prepare an internal Hydro One guideline delineating the transmission line loss process that Hydro One will follow and is accountable for" and "initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at the next rate application" [1].

Stantec carried out a review of Hydro One's transmission line loss processes with a view to assess the principles and completeness of such processes and to identify potential opportunities to cost-effectively reduce transmission line losses.

2.0 SCOPE

This report documents the findings and recommendations resulting from Stantec's review.

2.1 LIST OF REVIEWED DOCUMENTS

Stantec reviewed Hydro One's Transmission Line Loss Guideline as well as the following documents:

1. EPRI Hydro One Transmission Losses Report
2. National Grid Strategy Paper
3. CEER 2017 Report and CEER 2020 Report
4. Independent Electricity System Operator ("IESO") transmission losses presentation for public information sessions

In addition to these documents, Stantec's review leveraged its knowledge of line loss practices in other jurisdictions and extensive professional experiences.

2.2 DELIVERABLES

Stantec's scope of work and deliverables for this project consisted primarily of the following:

1. Providing comments on the principles and completeness of Hydro One's transmission line loss processes including Hydro One's Transmission Line Loss Guideline.
2. Identifying potential additional opportunities to cost effectively reduce transmission line losses, which could include improved processes, option analysis methodologies, documentation, and reporting.
3. Participating in Hydro One's May 12, 2021 Line Loss Stakeholder Consultation session and considering and incorporating resulting comments in the preparation of this report.

3.0 TRANSMISSION LINE LOSSES

A transmission network is an electrical highway through which electrical power flows. It connects loads or consumers to the generators or producers of electrical power. Power flow in a transmission network causes transmission losses, which will always exist and only the magnitude of losses can be managed.

A transmission network primarily consists of the following key elements:

1. Transmission lines, including transmission towers, conductors, and insulators
2. Transmission stations, including transformers and breakers

Transmission line conductors and transformers are the major contributors to line losses. These elements are made of physical conductors and have finite amount of resistivity which opposes the flow of electrical energy. This opposition to the flow causes losses which dissipate as thermal energy, and the remaining amount of electrical energy serves the loads or consumers. Generally, transmission losses may vary from 1% to 5% depending on the design and operation of the transmission network.

Transmission losses can be expressed as follows, and also shown in Figure 1.

Transmission Losses = (Generation + Import) – (Load + Export)

Figure 1: Transmission Losses in Power System

The power system network losses come from different elements installed in the system. However, the heat or thermal loss which is directly related to current flow is the most significant one and discussed in this document.

The thermal loss comes from the resistance of the element through which power flows and is expressed in (1).

$$Loss = I^2 \text{ x } r \tag{1}$$

where,

I = current flow in the element

r = resistance of the element

Transmission line losses can be managed by primarily adjusting current flow *I* and resistance *r*. The current flow *I* becomes the function of system operation in a power system network once the transmission system elements are built and energized. Resistance *r* is a function of the physical characteristics of the transmission system elements, and it will vary for different materials and technology. The system equivalent resistance will be modified once the planned elements are installed and energized and will remain constant unless any physical changes happen to the system. It is important to note, once the system is built, transmission line losses become function of load, generation dispatch and system operation (i.e., current flow).

3.1 FACTORS OR FUNCTIONS IMPACT TRANSMISSION LINE LOSSES

Transmission line losses are a function of system configuration and vary with load and generation in the system. The system configuration of a power system network usually remains unchanged unless lines are taken out of service due to expansion, maintenance, or retirement.

The factors and functions which influence transmission line losses can be identified as:

1. Planning
2. Design
3. Equipment Selection
4. Load Profile
5. Generation Dispatch
6. System Operation
7. System Voltage

It is important to note, once the system is built transmission losses become a function of load profile, generation dispatch and system operation. Hydro One's role is limited to planning, design, equipment selection, and system operating voltage (within approved limits).

3.2 TRANSMISSION LINE LOSS MANAGEMENT

In a restructured electricity market (e.g., the Ontario system), the roles and responsibilities related to the network and market operation are defined and assigned to multiple authorities and entities. In general, the following entities or a combination of them, operate in a network depending on the network and market structure:

1. Independent System Operator
2. Transmission Facility Owner or Transmitter
3. Independent Power Producer
4. Distribution Facility Owner or Distributors
5. Market Surveillance Authority
6. Balancing Pool or Authority
7. Energy Board or Utility Commission
8. Utility Consumer Advocate

In general, line loss management is not a direct task that is assigned to any entity in a restructured market. Line loss is generally one of the factors considered and evaluated during the planning, design, and equipment selection phases by responsible entities. However, it is unlikely for an entity to initiate a project solely for transmission loss reduction.

The other important functions that significantly impact transmission line losses are generation dispatch and network operation. In a restructured market, the underlying assumption is that the market participants' competitive bids will lead to an efficient overall system dispatch.

3.3 TRANSMISSION LINE LOSSES AND RELATED RESPONSIBILITIES IN ONTARIO

The following are IESO's key roles and responsibilities related to transmission line losses:

1. Operation of the system – the IESO is responsible for day-to-day operation of the Ontario electricity system and market.
2. Planning and design of the system
    a. the IESO is responsible for the planning of the transmission system (system topology), with focus on system adequacy and reliability.
    b. Planning of the system is supported by transmitters and distributors. Regional planning in Ontario follows the OEB-endorsed process which requires the participation of the IESO, Hydro One and local distributors.

Hydro One is the largest transmitter in Ontario. Hydro One's role and responsibilities related to transmission line losses are limited to:

1. Transmission system planning in coordination with the IESO for areas in Ontario where Hydro One is the transmitter.
2. Selection and procurement of equipment for the transmission system.
3. In addition to owning and maintaining transmission facilities, Hydro One is responsible for the detailed design of the transmission facilities, including developing equipment standards and selecting appropriate equipment [3].

The high-level process, roles and responsibilities related to transmission system planning, design, and operation can be shown in Figure 2.

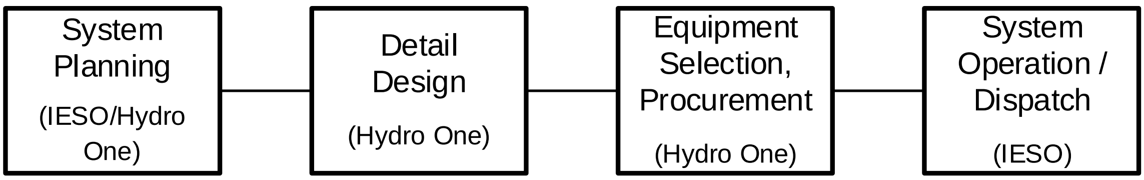

Figure 2: Transmission System Planning and Operation Roles and Responsibilities

During system planning, planners may consider the addition of a new segment in the transmission system or replacement (or upgrade) of an existing segment due to an asset condition or capacity limit issue. The scope of Hydro One's responsibility related to transmission line losses ends when planning, detailed design, selection and procurement of equipment, construction and energization are completed. Beyond this point, the IESO operates the system according to approved operational and market rules and procedures. As such, the day-to-day operation becomes the IESO's responsibility and losses become a function of current flow in the transmission network. Transmission line losses may considerably vary based on operational scenarios.

3.4 TRANSMISSION PLANNING PROCESS

A system planning study for expansion, reinforcement or replacement generally starts with the determination of load forecast and existing system condition. Based on study cases that simulate operational and dispatch scenarios, the study is completed to identify system issues and needs (with reference to applicable planning criteria), which lead to the development of solutions.

The proposed solutions generally reflect a range of considerations with technical, reliability, regulatory, economic, and environmental aspects. For instance, the technical evaluation and selection of a wires vs. non-wires solution could in turn impact the economic, reliability and environmental aspects. Line losses are generally considered as part of the economic aspect of the system planning process.

The optimal option is selected considering factors including equipment size and cost, terrain of right of way, length of the line, and loss savings in case of a wires solution. The equipment cost is generally estimated based on the following equation:

$$\text{Effective Equipment Cost} = \text{Initial Equipment Cost} + \text{Cost of Losses}$$

Some jurisdictions consider loss savings, not cost of losses, while comparing the alternatives for selecting equipment. Some jurisdictions also perform detailed loss assessments based on hourly load generation scenarios in order to evaluate the cost of losses for different planning options. The optimal solution is selected once the cost of losses is considered against all the decision-making metrics.

The planning process is based on many assumptions, such as, load and generation profile, system condition, integration of renewable generations, retirement of fossil fuel generation and resource availability. Any one of these assumptions and changes may impact the outcome of the planning process.

3.5 SYSTEM OPERATION AND TRANSMISSION LINE LOSSES

The scope of Stantec's review does not include transmission line loss-related practices from an IESO real-time operations perspective; however, it is important to recognize that system operations may significantly impact transmission line losses. Generally, a system plan is developed based on load and generation forecast in a system. A system planner considers planning scenarios including high, low, and other relevant load scenarios designed to approximate actual operational scenarios.

Typically, a complete cycle of transmission system planning and execution may take 5-10 years depending on the size and complexity of the plan. In 5-10 years after the inception of the planning process, actual operational scenarios on the system may have become significantly different from the original planning assumptions. Such differences may arise due to changes in regulation or policy, load profile, load location, load distribution, generation profile, generation location, economy, and even unexpected events like the pandemic, which may significantly or permanently alter the concentration and magnitude of power flow and cause associated changes in transmission losses.

4.0 DOCUMENT REVIEW

As noted above, the OEB in EB-2019-0082 directed Hydro One to "Initiate an independent third-party review of its own processes for cost-effectively reducing transmission line losses, to be filed at the next rate application and fulfill all of the requirements of the settlement proposal on loss reduction".

As part of its independent third-party review, Stantec reviewed Hydro One's Transmission Line Loss Guideline (attached as Appendix A) and other documents specified in Section 2.1. The following Section 4.1 summarizes the Hydro One Transmission Line Loss Guideline and Stantec's conclusions.

4.1 HYDRO ONE TRANSMISSION LINE LOSS GUIDELINE

Hydro One developed its Transmission Line Loss Guideline as part of fulfilling the OEB's direction. The Guideline captures the process and steps for Hydro One planners to evaluate and rank investment alternatives based on the cost of impact of transmission line loss.

The Guideline is based on the following three principles:

1. This Guideline shall be consistent with the OEB's direction in EB-2019-0082 with respect to developing a guideline for transmission line losses.

2. Transmission line losses shall be assessed for projects meeting a documented materiality threshold where transmission line investments are considered and where losses may have a material impact on the selection of alternatives.

3. Transmission losses are deemed to be material if they change the relative ranking of the transmission alternatives.

The Guideline describes how Hydro One intends to incorporate the impact of the cost of losses in its capital investment decision. Hydro One adopted a two-step process for alternative selection, which starts after alternatives are initially ranked based on the estimated capital investment cost.

The first step of the process employs a conservative screening approach, which helps to confirm whether the evaluation of alternatives warrants a more detailed line loss analysis. In this first step, hourly losses and cost of losses are calculated for a year at peak flow. The cost of losses is added to the total cost of each alternative, allowing planners to derive a ranking based on the loss-adjusted cost. Compared to the initial ranking based on estimated investment cost alone, any change in the ranking would trigger the second step of the process.

In the second step, transmission line losses and costs will be calculated for a year using hourly flow. This is then used for the final ranking of alternatives. Based on the total of annual revenue cost and annual losses cost, the lowest cost alternative is selected.

Stantec found the two-step process provides clarity and efficiency for the purposes of incorporating the cost of losses into alternatives evaluation and selection. The first step screening process helps to determine whether a more detailed analysis is required and could result in a significant amount of time being saved. The second step may involve the preparation of an hourly power flow profile for a year, which would require a number of assumptions such as load and generation dispatch, system condition, location of new generation, retirement of fossil fuel generation, and energy price.

Based on its review, Stantec concluded that overall, Hydro One's Transmission Line Loss Guideline provides a reasonable approach for determining the cost impact of losses. The Guideline provides an appropriate framework for making decisions in consultation with the IESO for customer connections, system reinforcement, system facility refurbishment and local area supply investments

To set the context for Stantec's findings based on the review of various industry reports, Sections 4.2 to 4.5 below summarize the EPRI Hydro One Transmission Losses report, National Grid Strategy Paper, CEER 2017 Report, and CEER 2020 Report.

4.2 EPRI REPORT ON TRANSMISSION LINE LOSSES

Hydro One previously engaged EPRI [2] to review Hydro One's line loss mitigation efforts in comparison to industry best practices. The resulting EPRI Hydro One Transmission Losses Report noted that transmission projects are initiated from a system requirement perspective and not for the purpose of loss reduction only, which is consistent with the National Grid Strategy Paper and Stantec's industry knowledge and practice. EPRI's report summarized that transmission loss mitigation can be addressed in three ways:

1. Equipment characteristics
2. Voltage level
3. Power flow control

EPRI conducted a utility survey related to their initiatives on transmission line losses. The survey of 25 utilities identified that the following preferred options are considered by the utilities:

1. Use of lower loss conductors
2. Installation of low-loss transformers
3. Raising nominal voltage
4. Optimizing voltage level
5. Re-direct power flow

In addition to the survey, EPRI reviewed the planning criteria and guidelines of major system operators in the USA.

The key findings of the EPRI report are as follows:

1. Transmission losses and their mitigation are not a focal point of transmission service providers, their independent system operators, or their regulatory bodies. At best, a few entities include the impact on losses that various design options may have in the selection of their project solutions.

2. Transmission Projects are initiated based on system need to ensure adequacy and reliability of supply. No utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.

3. The industry's best practices address transmission losses during the design and purchase of assets, such as, reducing losses with proper conductor selection and transformer design.

4. Hydro One design practices are generally consistent with industry best practices for loss mitigation.

4.2.1 Hydro One's Line Loss Mitigation Efforts Mentioned in EPRI Report

EPRI noted that Hydro One has adopted the following steps in its transmission loss mitigation effort:

1. Operating the transmission network at the upper end of the voltage range.
2. Considering higher voltage conversion (e.g., 115 kV to 230 kV) where feasibility in terms of economics and reliability.
3. System reinforcement by building a new line or reconfiguring the system and using lower loss conductors.
4. For transformer losses, the following two steps are taken:
   a. During procurement, Hydro One considers losses in the transformer selection process resulting in the purchase of transformers with lower losses,
   b. Gradual replacement of older and less efficient designed transformer at existing stations with newer, more efficient design due to end-of-life or load growth considerations.
5. Insulation hardware systems are designed to eliminate corona.

4.2.2 EPRI Conclusion

The EPRI Hydro One Transmission Losses Report concluded that transmission losses cannot be avoided and can be mitigated to a limited extent with appropriate application of design. EPRI further concluded that loss mitigation is not a focal point of transmitters, system operators or regulators and no utility pursues transmission projects solely based on potential loss savings.

EPRI concluded that Hydro One's design practices are generally consistent with industry best practices related to loss mitigation.

4.3 NATIONAL GRID STRATEGY PAPER

The National Grid Strategy Paper [4] was published in November 2013 and revised in September 2014.

This paper outlines National Grid's strategy for taking transmission losses into account in investment decision-making. This paper also acknowledges that transmission losses are only one of the economic factors which need to be considered when making investment decisions related to transmission network development.

The National Grid Strategy Paper describes the methods of accounting for losses via National Grid's investment processes. The paper also outlines considerations of losses in specifications and procurement processes and estimates of the impacts of key load and non-load developments on transmission. The following key aspects are discussed in this paper:

1. The consideration of transmission losses through investment planning – develop a methodology to take transmission losses into account when planning load related reinforcement and non-load related asset replacement programs during the optioneering phase of investment planning.

2. Accounting for transmission losses in equipment specifications and procurement processes – determine the optimal specifications in relation to the transmission losses arising from the operation of the new equipment in asset procurement process.

3. The key load related developments on the National Grid electricity transmission network and the estimated impacts on transmission losses – summarize key development list and estimate the impacts of those developments on transmission losses.

4. A summary of National Grid's non-load related asset replacement programs and the estimated impacts of the programs on transmission losses.

5. Consideration of the impact of new technologies on transmission losses.

National Grid utilizes the Whole Life Value (WLV)[1] framework to support the selection of the appropriate investment option, backed by economically justified decisions based on a broad range of investment criteria that include transmission losses.

As an indication of the likely transmission loss impact of asset replacements in the RIIO-T1 regulatory period (2013 to 2021), the National Grid Strategy Paper provides various examples related to, for example, overhead line reconductoring, transmission cable replacement, and grid transformer replacement. The methods by which National Grid account for transmission losses in equipment specifications and procurement processes are outlined for cables, overhead lines, and transformers.

The trade-off between capital investment and transmission loss costs is also discussed in the National Grid Strategy Paper. National Grid notes that the effect of future technology development on the capital cost of providing increased capacity using existing assets (e.g., series compensation) or building new assets (e.g., HVDC links) should also be considered alongside their impacts on transmission losses.

4.4 COUNCIL OF EUROPEAN ENERGY REGULATORS (CEER) REPORT ON POWER LOSSES – OCTOBER 2017

The CEER 2017 Report [5] presents the level of losses from CEER member countries for 2010 to 2015 time period, highlights how smart meters and increasing distributed generation are likely to affect network losses, and provides a set of findings and recommendations. It includes case studies on the regulatory treatment of losses (e.g., the procurement of energy to cover losses and compensation issues).

The CEER 2017 Report makes the following recommendations related to reducing transmission system losses:

Overall:

1. Harmonize definitions for improved benchmarking.

2. Incentivize system operators to reduce losses instead of passing losses on to consumers.

[1] Whole life value, in general, represents economic, social and environmental aspects associated with the planning, design, construction, operation, decommissioning and where appropriate, the re-use of the asset or its constituent materials at the end of its useful life. WLV constitutes the optimum balance of needs and requirements, and the costs over the life of an asset.

3. Employ a life cycle costing approach that includes losses when making investment decisions.

Technical losses:

1. Increase operating and system voltage levels.
2. Apply less transformational steps to deliver electricity to consumers.
3. Utilize new and improved equipment.
4. Optimize network flows – reduce peaking.
5. In general, pursue network architecture and management that promote the highest efficiency.

Non-Technical losses:

1. All countries should collect data on these types of losses.
2. Focus on more accurate recording of electricity consumptions through improved metering and the use of smart meters.
3. Reduce theft and other hidden losses.

4.5 2ND COUNCIL OF EUROPEAN ENERGY REGULATORS (CEER) REPORT ON POWER LOSSES – MARCH 2020

As with the 2017 report the CEER 2020 Report [6] analyzes the way power losses are defined, calculated, procured and treated under the various regulatory frameworks of the responding jurisdictions. Moreover, it statistically investigates the relationship between losses and certain other variables. The CEER 2018 Report makes the following recommendations for reducing transmission system losses:

1. Harmonize definitions of power losses in order to simplify comparison and enable proper benchmarking among countries,
2. Incentivize parties responsible for procurement of energy to cover losses to make this process as economical and efficient as possible,
3. Ensure that the incentives in (2) are set efficiently with an appropriate target and timeframe so as to avoid unintended consequences on system operators,
4. Move toward greater required transparency on technical and non-technical components of losses so as to facilitate proper regulatory treatment of those losses,
5. Where appropriate, implement newer or more efficient transformers and/or operate higher voltages on distribution grids in order to reduce technical losses,
6. Incorporate the reduction of non-technical losses in calculating the benefits of smart meter roll-out, such that smart metering is further encouraged,
7. Increase monitoring of non-technical losses with a view to gauging the effectiveness of potential solutions, such as increased penetration of smart meters.

5.0 COMPARATIVE ANALYSIS

To provide a comparative view of industry practices as they apply to transmission losses and assess alignment with Hydro One practices, this section summarizes the key recommendations from the above-noted reports and corresponding Hydro One practices.

Table 1 provides a comparative view of the National Grid Strategy Paper's key recommendations for loss accounting and relevant Hydro One practices.

Table 1 National Grid Strategy Paper Recommendations and Hydro One Practices

National Grid Recommendations	Hydro One Practice
Develop a methodology for consideration of transmission losses during the optioneering phase of investment planning.	Hydro One developed Transmission Line Loss Guideline to consider transmission losses for transmission line capital project decisions.
Determine optimal specifications in relation to transmission losses in equipment specifications and asset procurement processes.	Hydro One considers lower loss equipment in combination with other criteria, in its specifications and procurement processes (line and transformer).
Estimate the impacts on transmission losses for key load related developments to the transmission system.	Hydro One transmission planners follow the Transmission Line Loss Guideline to account for losses in load related development such as network system reinforcement.
Estimate the impacts on transmission losses on non-load related asset replacement programs.	Hydro One transmission planners follow the Transmission Line Loss Guideline to account for losses in non-load related development such as existing transmission system facility refurbishment.
Consider potential application of new and alternative technologies to the transmission system and these technologies may have impact on transmission losses.	Hydro One considers whether new technology may be economical and reliable in the system as a part of transmission planning.

Table 2 shows a comparative view of the CEER 2017 Report's key recommendations related to transmission line loss and relevant Hydro One practices.

Table 2 CEER 2017 Recommendations and Hydro One Practices

CEER 2017 Recommendations	Hydro One Practice
Incentivize system operators to reduce losses instead of passing losses on to consumers	Stantec believes this recommendation is not applicable to Hydro One.
Employ a life cycle costing approach that includes losses when making investment decisions	Stantec found that Hydro One introduced the annual total cost analysis as part of its alternative selection described in the Transmission Line Loss Guideline.
Increase Voltage Level	Stantec found that Hydro One usually operates close to the maximum operating voltage limits. For example, it operates near 250 kV and 127 kV in many parts of its transmission system which are at the higher end of nominal 230 kV and 115 kV voltage level.
Apply less transformational steps to deliver electricity to consumers	Hydro One has typically one level of voltage transformation from 230 kV or 115 kV to 44 kV, 27.6 kV or 13.8 kV for serving most customers connected at lower voltages.
Optimize network flows – reduce peaking	Stantec believes this is not applicable to Hydro One.

CEER 2017 Recommendations	Hydro One Practice
Pursue network architecture and management that promote the highest efficiency	Network architecture and management are observed to be generally managed efficiently. Higher voltages, less transformational steps, new and improved equipment are implemented where appropriate. These measures are reviewed regularly by Hydro One, the IESO and local distribution companies through the OEB Regional Planning Process.
Focus on more accurate recording of electricity consumptions through improved metering and the use of smart meters	Hydro One follows the revenue metering standards prescribed by the IESO market rules.
Reduce theft and other hidden losses	Stantec found Hydro One generally actively monitors for electricity theft.

Table 3 shows a comparative view of the CEER 2020 Report's key recommendations related to the transmission system and relevant Hydro One practices.

Table 3 CEER 2020 Recommendations and Hydro One Practices

CEER 2020 Recommendations	Hydro One Practice
Incentivize parties responsible for procurement of energy to cover losses to make this process as economical and efficient as possible.	Stantec understands this is not applicable to Hydro One.
Move toward greater required transparency on technical and non-technical components of losses so as to facilitate proper regulatory treatment of those losses.	In Ontario, the planning process is open and transparent as IESO, Hydro One and the local distribution companies follow the OEB Regional Planning Process. Losses are considered in evaluating optimal alternatives and the process is described in Hydro One's Transmission Line Loss Guideline.

6.0 SUMMARY

Based on the foregoing, Stantec provides the following summary.

Line Losses

Transmission line losses occur in a power system as resistivity of the network elements opposes the flow of current. Line losses are inevitable, and a function of system configuration and losses vary with load and generation dispatches, as the system changes operationally.

System Planning and Mitigation

As a common industry practice, a system planning study is initiated to assess forecast expansion, reinforcement, replacement, or refurbishment of system elements. Transmission expansions and reinforcements are often considered to remedy load growth scenarios, and equipment replacements or refurbishments are considered for non-load issues. It would be unusual for an entity to initiate a system project solely to reduce line losses. In the process of system planning activities, an optimal alternative is usually selected based on technical adequacy, reliability, as well as loss optimization and mitigation.

In an existing power system where no development is planned, loss mitigation alternatives are limited to upgrading the voltage level or increasing the number of parallel lines. Upgrading the system voltage generally requires replacing major transmission elements, which is usually uneconomic. Hydro One's system is already designed to robust reliability criteria and adding more lines in parallel would not generally be cost effective.

Document Reviews

In addition to Hydro One's Transmission Line Loss Guideline, Stantec reviewed the National Grid Strategy Paper, CEER 2017 Report, and CEER 2020 Report. Stantec found that Hydro One's practices are generally aligned with the recommendations applicable to transmitters.

Stantec also reviewed EPRI's Hydro One Transmission Losses Report from 2018, which examined Hydro One's planning and design processes relative to the criteria/guidelines of major U.S. system operators as well as EPRI's survey of a sufficiently wide range of utilities to provide reasonable benchmarks for comparison. Stantec concurs with the findings in the EPRI report which concludes that Hydro One's design practices are generally consistent with industry best practices for line loss mitigation.

Hydro One Transmission Line Loss Guideline

Hydro One prepared the Guideline to enable a cost evaluation of transmission losses as well as a process for incorporating those costs into the selection of alternatives.

The Guideline primarily consists of two steps - a screening step, and a detailed analysis step. Stantec found the screening step is reasonably conservative in utilizing the hourly annual peak flow losses. If the initial rankings of the potential alternatives change after accounting for the cost of losses, the detailed step is invoked. The detailed step then calculates cost of losses utilizing annual hourly network flows. The least cost alternative is then identified based on total cost, which is a sum of annual revenue cost and cost of annual losses.

Stantec's review found Hydro One's process and calculation appropriately evaluate losses when considering future investments in transmission lines, asset replacements, or system reinforcement.

7.0 CONCLUSION

Stantec concluded the following observations:

1. Hydro One's practices related to transmission line losses are generally aligned with the recommendations outlined in the National Grid Strategy Paper, CEER 2017 Report, and CEER 2020 Report in relation to transmitters.

2. Stantec concurs with the findings in the EPRI report which concludes that Hydro One's design practices are generally consistent with industry best practices for line loss mitigation.

3. Stantec found the Hydro One Transmission Line Loss Guideline provides a reasonable approach for the evaluation and selection of the preferred investment alternatives considering the cost of losses.

Given the objectives and scope of its review, Stantec concluded that Hydro One follows industry best practices with respect to transmission line loss management. Hydro One's Transmission Line Loss Guideline provides a reasonable, clear and efficient process for the purposes of incorporating the cost of losses into alternatives evaluation and selection.

8.0 RECOMMENDATIONS

Stantec provides the following recommendations to Hydro One with respect to transmission line loss management:

1. Ensure implementation and consistent use of the Transmission Line Loss Guideline for new investments that impact transmission line losses.
2. Track the number of projects that have been assessed for transmission line loss mitigation and the associated MW reduction in losses as documented in approved business cases.

9.0 REFERENCES

[1] Ontario Energy Board. *DECISION AND ORDER, EB-2019-0082, HYDRO ONE NETWORKS INC., Application for electricity transmission revenue requirements beginning January 1, 2020 until December 31, 2022*. April 23, 2020.

[2] Electric Power Research Institute, *Hydro One Transmission Losses 3002012721, Technical Report*, March 2018.

[3] Independent Electricity System Operator, *Transmission Losses Public Information Sessions Presentation, Public Information Session #1*, September 6, 2019.

[4] National Grid, *National Grid's Strategy Paper to address Transmission Licence Special Condition 2K: Electricity Transmission Losses*, September 2014.

[5] Council of European Energy Regulators, *CEER Report on Power Losses, Ref: C17-EQS-80-03*, October 18, 2017.

[6] Council of European Energy Regulators, 2nd CEER Report on Power Losses, Ref: C19-EQS-101-03, March 23, 2020.

APPENDIX A

Hydro One Transmission Line Loss Guideline – R0

Transmission Line Loss Guideline – R0

Purpose

The purpose of the Transmission Line Loss Guideline (the "Guideline") is to i) delineate the transmission line loss process that Hydro One will follow and is accountable for, and ii) where transmission line losses are material, describe an investment option analysis methodology for transmission line capital projects.

The Guideline is intended to satisfy the Ontario Energy Board's direction in EB-2019-0082 in respect of transmission line losses.[1]

This Guideline applies to Hydro One Transmission Planning employees (the "Planner") planning for Hydro One's transmission system.

Revision Statement

This is the first version of this document.

R0 – February 26, 2021

Principles

- This Guideline shall be consistent with the Ontario Energy Board's direction in EB-2019-0082 in respect of developing a guideline for transmission line losses.
- Transmission line losses shall be assessed for projects meeting a documented materiality threshold where transmission line investments are considered and where losses may have a material impact on the selection of alternatives.
- Transmission losses are deemed to be material if they change the relative ranking of the transmission alternatives.

Contents

[1] EB-2019-0082 Decision 23 April 2020, Transmission Line Loss Reduction Opportunities (Issue 8), p. 56.

1.0 Background

Line losses occur in the transmission system as power flows from the generation source to the load (i.e., energy that is dissipated as heat when electricity flows through the transmission system). The amount of losses is dependent on the specific type of transmission line conductor, other transmission assets (i.e., transformers), the amount of power flowing in the line, the operating voltage and the length of the line.

Hydro One's ability to manage line losses is limited to its role as a Transmission Owner (asset owner) in planning, selecting, maintaining and operating its transmission equipment, subject to the inherent limitations of such equipment. Options available to manage line losses include the following:

- Upgrading the system voltage or building a new line in parallel with an existing line offers an opportunity for loss reduction. However, rebuilding transmission facilities or building new lines to reduce line losses would not be economically justifiable unless the new facilities are also required to provide capacity or ensure reliability.
- Upgrading the conductor size or using a lower loss conductor type such as the Aluminum Conductor Steel Reinforced Trapezoidal Wire (ACSR/TW) conductor[2] will reduce line losses. However, such upgrades are limited by the capability of the original tower structures, which generally can only accommodate conductors of the same or slightly larger size before costly major tower / structural reinforcements become necessary.

2.0 Scope

This Guideline shall be followed when considering transmission system investments which include:

- new customer connections
- local area supply investments
- network system reinforcement
- existing transmission system facility refurbishment

[2] The ACSR/TW conductor has the same diameter as the conductor being replaced, but has more aluminum content and a 10 to 20% lower resistance. The net effect is to reduce the losses on that line by the corresponding amount.

3.0 Option Analysis Methodology

Where transmission line investment alternatives are considered, the Planner shall complete an Options Analysis using the Transmission Line Loss Option Analysis workbook.

The Options Analysis shall be based on expected flows under normal system conditions (e.g., based on typical conditions in the last 12 months in terms of generation dispatch, reactive power dispatch, interface flows, etc.). If the flows are expected to change significantly in the future (e.g. increase by over 25% over the next 10 years), then the forecast 10th year load shall be used.

The Option Analysis shall follow the methodology described below:

1. The Planner shall rank the investment alternatives in ascending order by the Planner's estimated capital investment cost of each alternative.

2. The Planner shall convert the estimated capital investment cost of each alternative to an annual revenue cost (ARC) by applying the annual cost factor (ACF)[3] to the estimated capital investment cost.

3. The Planner shall determine the difference between the annual transmission line losses that are expected to materialize under each alternative relative to the current transmission line losses. The annual transmission line losses shall be determined by applying the losses at **peak** flow for 8760 hours (i.e. worst case scenario) for s**creening** purposes.

4. The Planner shall determine the cost of annual losses (CAL) by multiplying the annual transmission losses determined in Step 3 by the annual average energy price[4] provided by the IESO.

5. The Planner shall determine the total annual cost by adding the ARC and the CAL, and rank the alternative investments to see if the ranking established at step 1 has changed.

6. If the ranking has not changed from that at step 1 then **no further study is required**. The expected MW loss reduction at peak load will be reported in the Business Case Summary (BCS) for the preferred alternative.

7. If the ranking has changed as a result of the inclusion of losses, then a detailed analysis will be required to determine the annual transmission losses for each alternative using **hourly** flow instead of peak flow in Step 3 above. The CAL for each alternative will be determined as in Step 4 above.

8. The Planner shall determine the total annual cost by adding the ARC and the CAL, and rank the alternative investments.

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[3] The Decision Support Department in Business Planning shall provide the ACF in the Transmission Line Loss Option Analysis workbook.

[4] Please look up the HOEP at the IESO website.

9. If the ranking at step 1 has changed using the assessment in step 7, then the impact of the alternative investments on transmission line losses shall be considered when selecting the preferred alternative. The expected MW loss reduction at peak load will be reported in the BCS for the preferred alternative.

4.0 Examples

Example 1: Ranking of alternatives does not change

This example shows two investment alternatives being considered for a project. Alternatives 1 and 2 cost $24M and $60M, respectively. The transmission losses under the two alternatives are 1.2MW and 0.6MW respectively. The alternatives are screened using the losses at peak flow. The ranking of the alternatives does not change when considering transmission line losses. Alternative 1 remains the lowest cost. Therefore, transmission line losses are not material to the investment decision, and a detailed assessment of transmission line losses is not required.

(all costs in $M)	**Alternative 1 – Reconductor**	**Alternative 2 – Additional Circuit**
Planner's Estimated Capital Investment	24.0	60.0
Ranking	**1**	**2**
Screening		
Annual Revenue Cost (ARC)	1.79	4.49
Cost of Annual Losses (CAL)	0.31	0.16
Total Annual Cost (ARC + CAL)	2.11	4.65
Ranking - Screening	**1**	**2**
Ranking has not changed – detailed assessment not required		

Example 2: Ranking of alternatives does change

This example considers four investment alternatives for reconductoring a transmission line. Apart from like for like replacement, the alternatives consider use of larger size, lower loss conductors.

The alternatives are screened using losses at peak flow, which causes the ranking of alternatives to change. Alternative 4 becomes the lowest cost alternative. If the ranking of alternatives changes following the screening assessment, transmission losses are deemed material to the investment decision and a detailed assessment is done.

The detailed assessment shows that while Alternative 4 has a higher initial capital cost, factoring in the losses, makes it the lowest cost and preferred alternative. In this case transmission losses are material to the investment decision and are therefore taken into consideration for selecting the preferred alternative.

(all costs in $M)	**Alternative 1 – 795 kcmil**	**Alternative 2 – 997.2 kcmil**	**Alternative 3 – 1192.5 kcmil**	**Alternative 4 – 1443.7 kcmil**
Planner's Estimated Capital Investment	7.8	8.0	8.5	8.6
Annual Revenue Cost (ARC)	0.58	0.60	0.64	0.64
Ranking	**1**	**2**	**3**	**4**
Screening				
Cost of Annual Losses (CAL)	0.97	0.79	0.69	0.57
Total Annual Cost (ARC + CAL)	1.55	1.39	1.33	1.21
Screening Ranking	**4**	**3**	**2**	**1**
Ranking has changed – detailed assessment required				
Detailed Assessment				
Cost of Annual Losses (CAL) - Detailed	0.20	0.17	0.14	0.12
Total Annual Cost (ARC + CAL)– Detailed	0.78	0.77	0.78	0.76
Ranking– Detailed	**4**	**2**	**3**	**1**

5.0 Business Case Summary (BCS)

Where transmission line investment alternatives are considered, the Planner shall complete the Transmission Line Loss Option Analysis workbook and retain a copy in the project folder on SharePoint.

The impact of the alternative investments on transmission line losses shall be taken into consideration and shall be documented in the BCS as follows: "This investment is expected to result in transmission line loss savings of __ MW at peak flow."

6.0 Accountabilities

The Transmission System Planning Division is accountable for the assessment of transmission losses and documenting the relevant findings in BCS as appropriate.

The Transmission Planning Division, with support from Decision Support Division for the financial factors, shall maintain the Transmission Line Loss Option Analysis workbook.

7.0 References

EB-2019-0082 – Decision and Order

Hydro One Transmission Losses, EPRI Technical Report, March 2018

8.0 Document Management

Owner/Functional Responsibility	Director, System Planning, Planning
Approver	Director, System Planning, Planning
Approval Date	March 1, 2021
Effective Date	March 1, 2021
Last Reviewed Date	March 1, 2021
Next Review Date	March 2022

9.0 Appendices

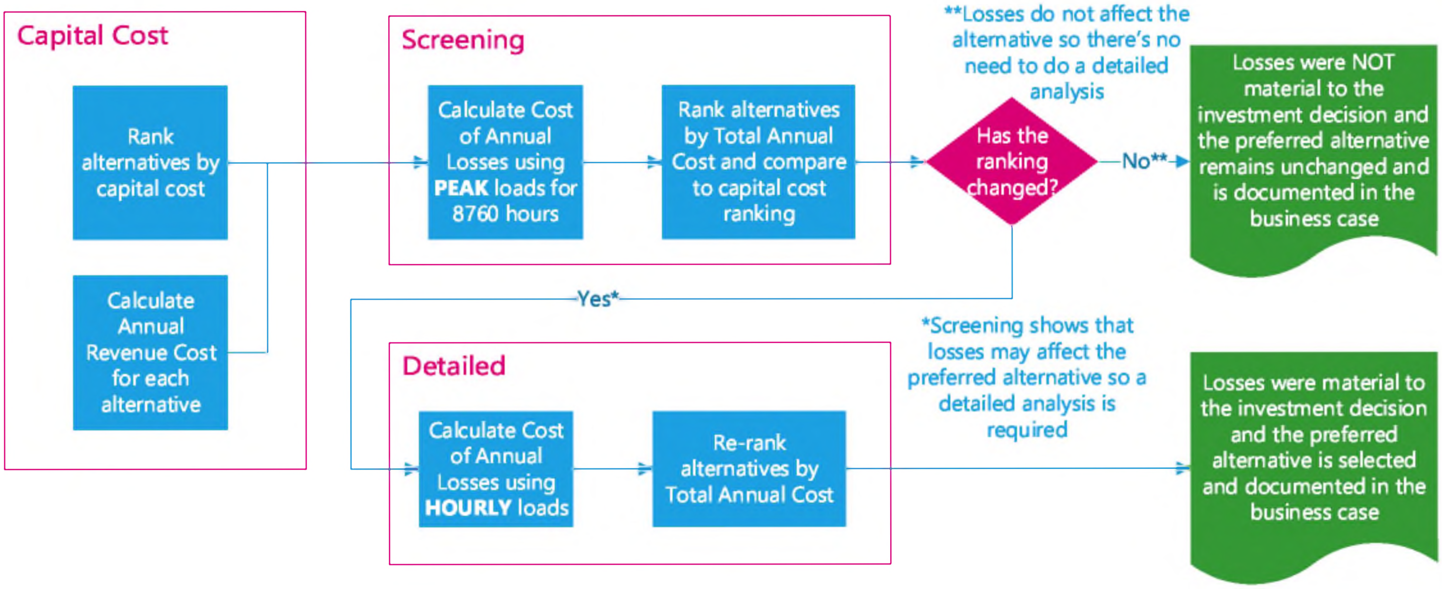
9.1 Rationale

In the Decision and Rate Order for EB-2019-0082 the Board accepted the settlement agreement between Hydro One and Environmental Defence, which included the development of a guideline for incorporating transmission losses into the planning process:

"3. Hydro One will prepare an internal Hydro One guideline delineating the transmission line loss process that Hydro One will follow and is accountable for. This will be developed in Q1 2020 and refined throughout the IESO stakeholder consultation as necessary.

4. In business cases for projects where transmission line losses are material, Hydro One will include an option analysis and report on transmission line losses. This will be implemented over the course of 2020 for any projects meeting a documented materiality threshold."

9.2 Transmission Line Loss Guideline Flowchart



9.3 Transmission Line Loss Guideline Workbook Example

SCREENING

Note: Use actual dollars, not $k or $M	Least Capital Expenditures Option 1	Option 2	Option 3	Option 4	Most Capital Expenditures Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Original rank	1	2	3	4	N/A
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	
Losses at Peak Flow (MW)	3.70	3.03	2.61	2.16	
Annual Losses assuming Peak (MWHR)	32,412.00	26,507.76	22,872.36	18,877.80	0.00
Incremental Annual OM&A	$ -	$ -	$ -	$ -	
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ 30.000
Annual Revenue Cost (ARC)	$ 584,248.02	$ 599,490.15	$ 637,809.33	$ 644,170.89	$ -
Cost of annual losses (CAL)	$ 972,360.00	$ 795,232.80	$ 686,170.80	$ 566,334.00	$ -
Preliminary Total Annual Cost	$ 1,556,608.02	$ 1,394,722.95	$ 1,323,980.13	$ 1,210,504.89	N/A
Revised Rank	4	3	2	1	

Losses affect Ranking of Alternatives - Detailed Analysis Required - See below

Fill in Detailed section below if Losses change Ranking

DETAILED

	Option 1	Option 2	Option 3	Option 4	Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	$ -
Annual Losses (MWHR - Detail)	6,828.00	5,565.50	4,801.50	3,997.00	
Incremental Annual OM&A	$ -	$ -	$ -	$ -	$ -
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ -
Annual Revenue Cost (ARC)	$ 584,248.02	$ 599,490.15	$ 637,809.33	$ 644,170.89	$ -
Cost of annual losses (CAL)	$ 204,840.00	$ 166,965.00	$ 144,045.00	$ 119,910.00	$ -
Total Annual Cost	$ 789,088.02	$ 766,455.15	$ 781,854.33	$ 764,080.89	N/A
Detailed Rank	4	2	3	1	

SECTION 2.4 - TSP - TRANSMISSION SYSTEM RELIABILITY

2.4.1 INTRODUCTION

Hydro One's transmission system 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/NPCC or transmission customers. NERC determines the reliability of a bulk power system in terms of adequacy and security of supply such that it 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 the elements could be due to causes such as equipment breakdown or adverse weather conditions, and has now been expanded to include physical or cyber-attacks.

Transmission customers typically view reliability in term of supply continuity. In terms of supply continuity, reliability is expressed as the frequency or duration of interruptions over a given period, typically a year, at the customer Delivery Point (DP).[1] Being a customer focused organization, Hydro One considers the uninterrupted delivery of electricity, from the customer's perspective, 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 repair a line connecting a customer DP would also be described as improving reliability.

Hydro One measures and actively monitors its transmission system reliability from the perspectives of both delivery and equipment. 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 begins by describing the categories of transmission assets. This is followed by a discussion of the determinants of reliability from both the bulk system and customer DP perspectives. It explains how various elements of the transmission system contribute to the reliability of the individual customer DPs and explains the difference between the bulk power system reliability and DP reliability. This section also discusses the performance of the various asset categories. Section 2.4.3 explains the relationship between capital investment and transmission system reliability as directed by the OEB in Hydro One's last Transmission Rate

[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.

application.[2] The section explains that investments made to maintain bulk transmission system reliability typically do not immediately impact DP reliability because, as explained in Section 2.4.2, most customers and load in Ontario are served by dual circuits. This section also discusses Hydro One's transmission expenditures over various asset categories. Section 2.4.4 describes the Ontario reliability standards and measures and TSP Section 2.4 Attachment 1 discusses First Nation reliability performance.

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 the purpose of rate allocation. These categories are also helpful in understanding reliability.

- **Network Assets** – These assets are comprised of the integrated transmission facilities operating at 500kV, 230kV or 115kV that link major sources of generation to major load centers.
- **Line Connections Assets** – These assets are comprised of transmission circuits and intermediate stations operating at 230kV or 115kV that are used to provide a connection between network stations and transmission load DPs.
- **Transformation Assets** – These assets are comprised of transformer stations owned by Hydro One which step down the voltage to below 50kV. These 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, is classified as a DP.

Along with the three major asset categories above, there are a three other categories:

- **Dual Function lines**, which serve both network and line connection functions and for the purpose of the reliability discussion are considered along with Line Connection assets.

[2] EB-2019-0082, Decision and Order, April 23, 2030, p. 56.

- **Generator Line and Transformation Connections** which connect generators to the transmission system. These are considered part of Network assets, unless they also supply customer DPs, in which case they are considered along with Line Connection assets.
- **Common Assets** comprise facilities that serve the operation of the overall provincial transmission system and include telecommunication 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 is necessary for the reliability of the network and these are considered along with Network assets.

The types of transmission assets are illustrated in Figure 1.

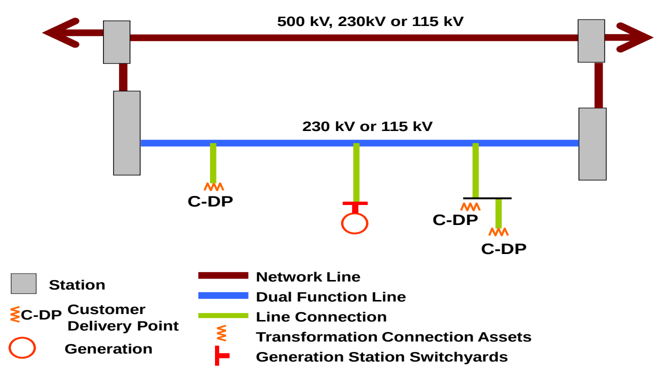


Figure 1: Types of Transmission Assets Illustrated

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 loss of one or more elements (line or transformer, etc.) will not result in any violation of thermal and stability limits. As a result of this, 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. Thus, typical DP interruption frequency and duration statistics do not provide complete information on the reliability performance of the network transmission system.

In general, no simple reliability indicators from the customer perspective, 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 also carries out annual reliability assessments for the current year, near-term and long-term to ensure that performance of the transmission system complies with the NERC Reliability Standards. Further, the IESO and Hydro One Grid Control 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, outages are minimized and if outages occur, the equipment is either 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 Delivery Points. In general outages on these assets directly affect DP Interruption (DPI) statistics. However, these DPI statistics are shaped to a great extent by the network configuration and historical development of the provincial transmission network under which loads larger than 75MW were generally provided 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 single line configuration, unless they are willing to pay the cost of the second supply.

Figure 2 below shows typical single and dual supply DPs. Generally, all DPs are provided with two transformers. 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 DP served with a dual supply, each line connects directly to a transformer and the two transformers are connected in parallel.

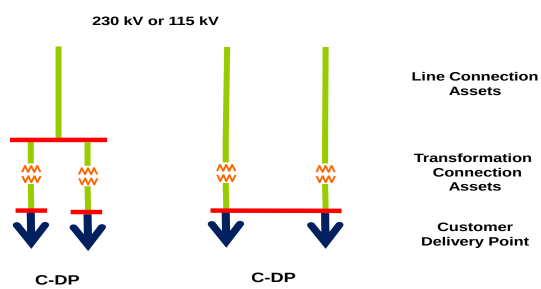


Figure 2: Single and Dual Supply DPs

DPs served by a single supply have lower loads and lower reliability than 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 case traverse through heavily forested or treed areas and therefore are susceptible to outages from broken branches or trees blowing into the line;
- 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 3 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 below shows average DP statistics for the 2011-2020 period.

Table 1 – Single Supply DPs 2011 - 2020*

Voltage Level	No. of DPs	% of Provincial Load	% of Provincial Outages	% of Provincial Outages Duration	DPs with Zero Outages	Annual Average DP Outage Frequency Occurrence	Annual Average DP Outage Duration Minutes
115kV	223	10.1%	77.2%	84.6%	3	3.32	154.8
230kV	35	4.8%	3.1%	3.3%	2	0.84	38.3
Total	**258**	**14.9%**	**80.3%**	**88.0%**	**5**	**2.98****	**138.8*****

**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.*

DPs served from double circuit lines generally have higher loads and a very high degree of reliability. DP interruptions are infrequent – once every 3-4 years or less and usually short in duration. The major exception is transformer failures that affect both incoming supplies where 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;
- there is an overlapping outage - where one supply circuit is out for maintenance and an outage occurs on the second supply circuit;
- the DP itself is affected, which typically can be due to weather or animal contact; or
- a tie-breaker outage takes both buses serving the DP out of service.

As shown in Table 2 below, dual supply DPs have extremely good reliability. Approximately 166 dual supply DPs have not experienced any interruption over the last ten years.

Table 2 – Dual Supply DPs 2011 -2020*

Voltage Level	No. of DPs	% of Provincial Load	% of Provincial Outages	% of Provincial Outages Duration	DPs with Zero Outages	Annual Average DP Outage Frequency Occurrence	Annual Average DP Outage Duration Minutes
115kV	299	25.7%	10.8%	5.7%	71	0.35	7.8
230kV	340	59.4%	8.8%	6.3%	95	0.25	7.5
Total	**639**	**85.1%**	**19.7%**	**12.0%**	**166**	**0.29****	**7.7*****

** 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.*

A comparison of Tables 1 and 2 shows that the majority of the interruptions occur on 115 kV single supply DPs with roughly 10.1% of the load seeing 77.2% of the outages. Interruptions on single supply 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 of an impact on 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 typically DP interruptions are due to equipment at the DP itself. 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, the IESO and the LDCs that are being supplied from the DP. This concern arises because replacing a failed transformer takes a considerable amount of time. At any point prior during the replacement of the failed transformer, an outage impacting the second line, whether on the line itself or on the second transformer, would result in a serious and lengthy DP interruption.

Another issue 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 up to 130-160% of its transformer rating depending on summer/winter 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 overloading 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 transmission facilities remain in-service. The station renewal program thus 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.

DP reliability statistics are a lagging indicator. They measure customer interruptions after these interruptions have already happened. By the time reliability statistics start to deteriorate for DPs served by dual supplies, numerous customers will have been affected and service to communities compromised.

2.4.3 TRANSMISSION ASSET CATEGORY EXPENDITURES

Hydro One transmission capital expenditures are geared towards ensuring that the transmission system continues to provide reliable supply. Table 3 provides a listing of the expenditures under the System Renewal category.

Table 3 – Hydro One 2023 – 2027 Net System Renewal Capital Expenditures ($M)

Pool	OEB Investment Category	2023	2024	2025	2026	2027	Total
Network	System Renewal	137.0	157.4	171.7	189.3	186.7	842.0
Line Connection	System Renewal	549.2	573.6	585.4	600.6	602.8	2911.5
Transformation	System Renewal	389.8	385.9	382.0	391.1	408.4	1957.3
Common	System Renewal	102.0	111.4	112.5	96.3	66.1	488.4
Grand Total		**1178.0**	**1228.3**	**1251.6**	**1277.3**	**1264.0**	**6199.2**

The largest expenditure category is for network assets. Expenditures in this category address refurbishment work at major stations such as Cherrywood TS, Claireville TS, Middleport TS, Lennox TS, and Nanticoke TS. This category also addresses refurbishment of 230kV network lines. This work is required to ensure that the transmission network meets all relevant IESO and NERC criteria however because of the redundancy of this infrastructure, these expenditures do not typically have an immediate impact on DP reliability statistics.

The second highest expenditure category is for the transformation pool under which transformers and Low Voltage (LV) yards at DESN stations are being refurbished. As above, while reliability of the dual supply DP is currently good, poor condition and obsolete transformers and connecting low voltage equipment pose a significant risk in terms of both delivery point reliability performance and public safety. Hydro One is committed to ensuring that these risks are minimized in the most cost effective manner through ongoing work on transformation pool assets. Again, this category of expenditures does not typically result in immediate improvement to DP reliability statistics because of the predominance of dual supply.

The third highest expenditure category is for connection lines refurbishment. The work in 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 – local distribution companies, First Nations communities and businesses, pipeline compressor stations, large load facilities such as mines and paper mills and generators. This category of expenditure does typically result in immediate improvement to DP reliability statistics.

The final category of expenditure is for Common Assets. This expenditure includes investments on telecommunication and other assets required for the overall 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, namely: equipment performance and delivery performance. 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. The delivery performance perspective establishes a measure of how reliably electricity is delivered to transmission customers such as the Hydro One distribution system, Local Distribution Companies and Transmission Direct Connect Customers. Being a customer focused organization, Hydro One considers the delivery of electricity 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 at the Transmission Consultative Committee on Outage Statistics (T-CCOS) with the Canadian Electricity Association (CEA). 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 between 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 Ontario Resource and Transmission Assessment Criteria.[3]

[3] IESO - Ontario Resource and Transmission Assessment Criteria. https://www.ieso.ca/en/Sector-Participants/Market-Operations/Market-Rules-And-Manuals-Library

2.4.4.1 DELIVERY POINT RELIABILITY MEASURES

Hydro One measures customer reliability by monitoring the frequency and duration of interruptions at DPs. There are two types of DPs. One type is the low voltage bus in Hydro One owned transformer stations and the other type is a demarcation point where a customer-owned station connects to the transmission lines. Because all DPs are ultimately supplied by the bulk transmission power system, a reliable bulk transmission power system is essential to the reliability and security of supply experienced at customer DPs. The table below summarizes the DP Reliability measures that are monitored.

Table 4 - 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 of interruptions in minutes experienced at DPs due to forced interruptions
	Delivery Point Unreliability Index – a measure of unsupplied energy[4]	Energy not supplied to customers caused by 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 CEA 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, setting targets and external benchmarking.

[4] This measure appears on the Hydro One Transmission Scorecard as "Unsupplied Energy (System Minutes)." See TSP Section 2.5.

- 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 under the DP performance outliers section. The standards, which may be found in Attachment 2, are summarized from a Hydro One document previously filed with the OEB: Customer DP Performance (CDPP) Standards, EB-2002-0424. Additionally, Attachment 3 provides definitions and detailed descriptions of the reliability measures used in this evidence.

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 5, below. This perspective enables Hydro One to assess the operational performance of transmission components, ensuring that the transmission equipment is functioning and operating effectively as designed.

Table 5 – Equipment Reliability Measures

Perspective	Measure	Description
Performance of Transmission System	Transmission System Unavailability	Captures the total duration transmission equipment is out of service due to unplanned outages, measured as a percentage

The Canadian Electricity Association (CEA) 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 the CEA 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 CEA 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, starting in 2017 CEA excluded extraordinary events from the CEA 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 whose impact on the transmission system exceeds one million MW-minutes, and that, in Hydro One's assessment, strongly skew the historical trend of the measure have been excluded consistent with the CEA methodology. These outages were not due to equipment failure or human error, which Hydro One considers to be controllable.

Hydro One also removes major events that exceed 10,000MW-minutes in unsupplied energy from its reliability metrics.[5] This exclusion threshold has been determined using a statistical method (log-standard deviation (β)) to identify major unsupplied energy events. This threshold corresponds to a CEA Degree of Severity Level 2 disturbance event. Hydro One has applied this exclusion threshold to performance tracking and target setting starting in 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 the CEA, Hydro One compares the reliability performance of its transmission system against the Canadian Transmission Utility average performance. The comparison of DP reliability performance is done at the system level, reflecting the system average of all DPs.

[5] If an event meets the threshold for an extraordinary event, it is also not considered as a major event to avoid double counting.

Hydro One's comparative reliability performance at the system level is illustrated in the following Figures:

- Figure 6 - frequency of momentary interruptions;
- Figure 7 - frequency of sustained interruptions;
- Figure 8 - overall frequency of interruptions;
- Figure 9 - average duration of sustained interruptions; and
- Figure 10 - DP unreliability index.

As the Figures below demonstrate, for all of the above metrics, Hydro One's performance is better than the CEA composite. CEA Composite values for 2020 will be available in late Q3 2021.

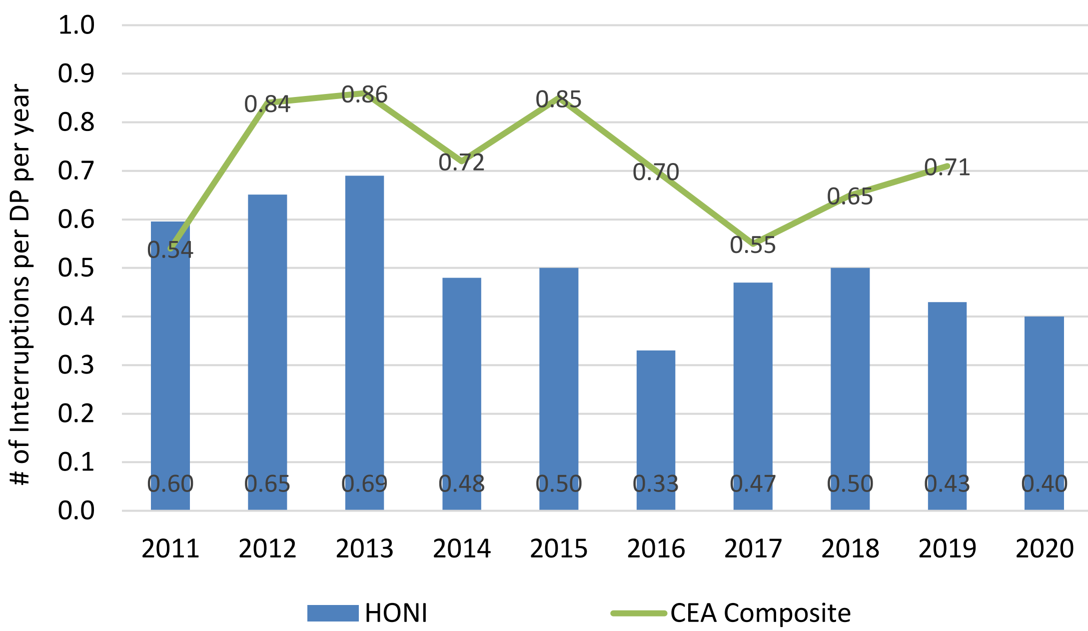


Figure 6: Frequency of Momentary Interruption, Hydro One vs CEA Composite[6]

[6] CEA Composite values include Hydro One performance for all measures.

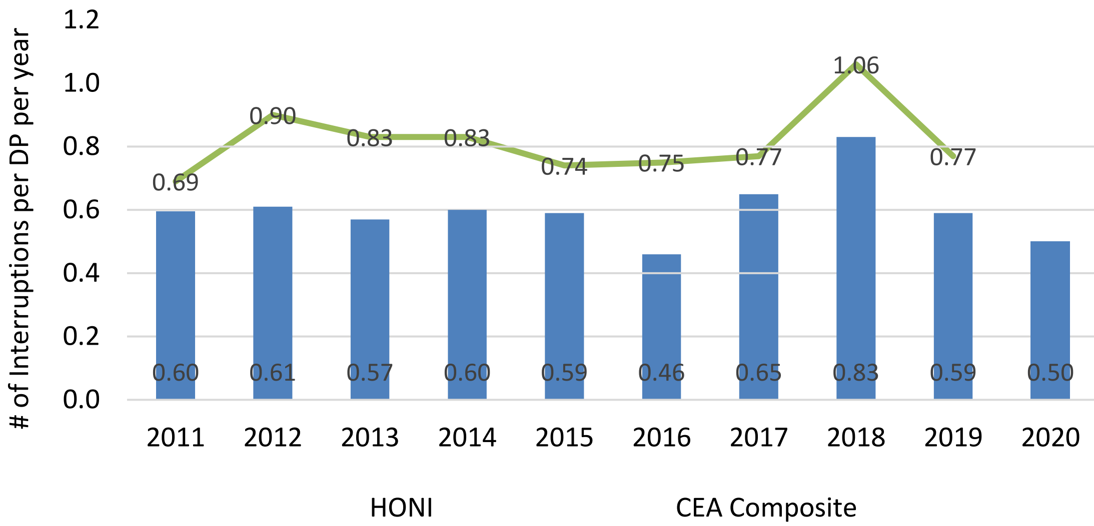


Figure 7: Frequency of Sustained Interruption, Hydro One vs CEA Composite

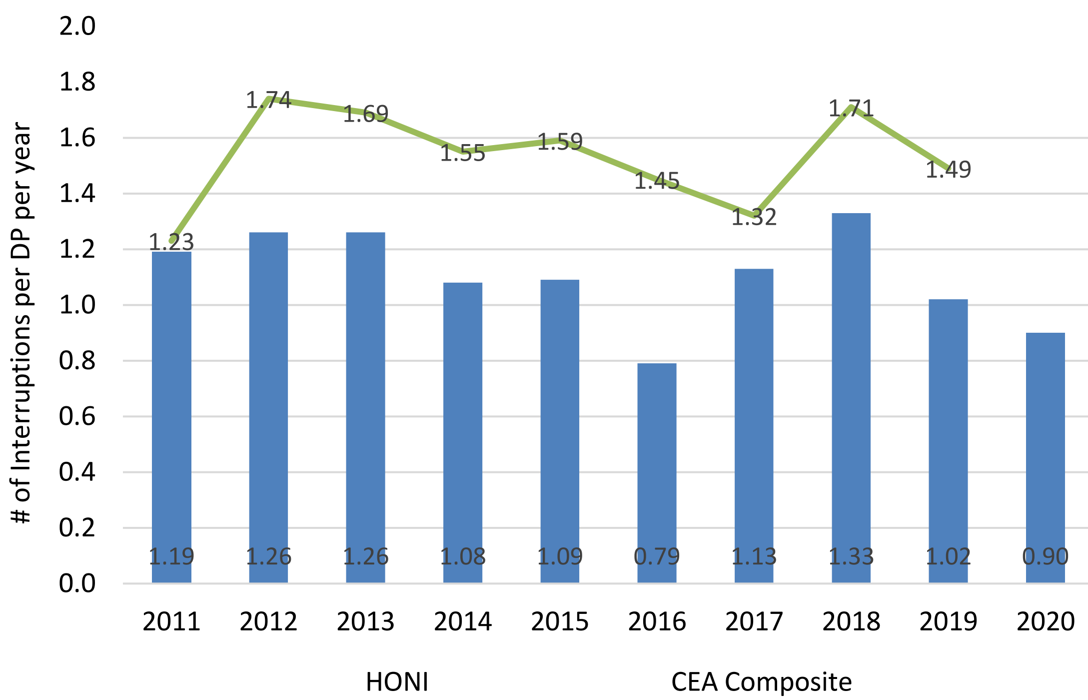


Figure 8: Overall Frequency of Interruptions, Hydro One vs CEA Composite

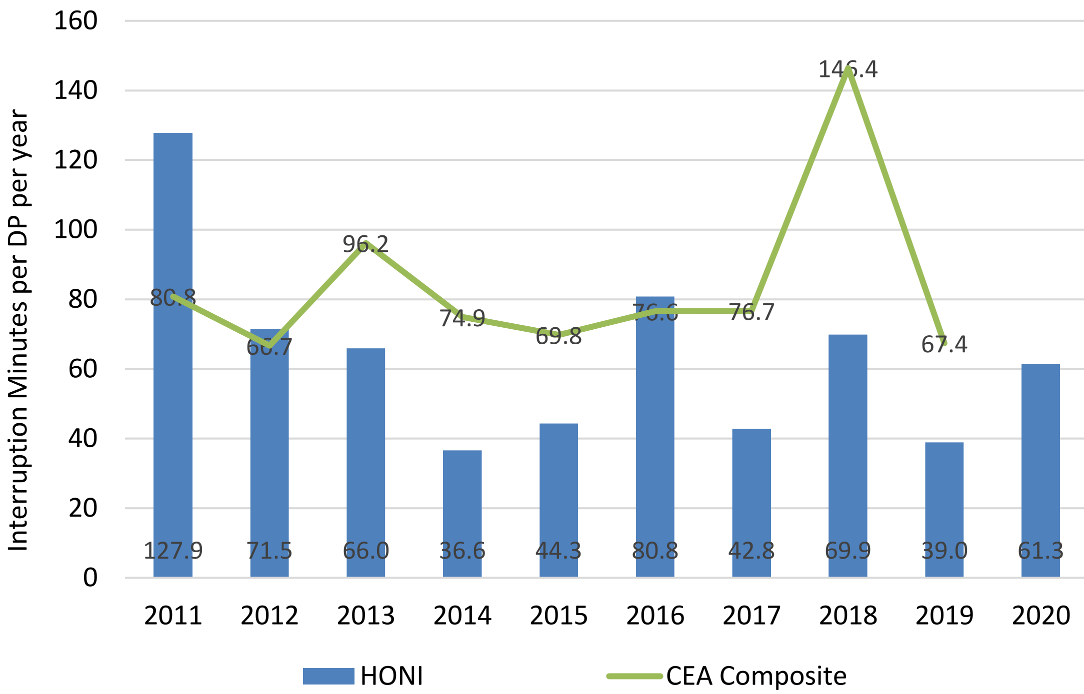


Figure 9: Average Duration of Interruption, Hydro One vs CEA Composite

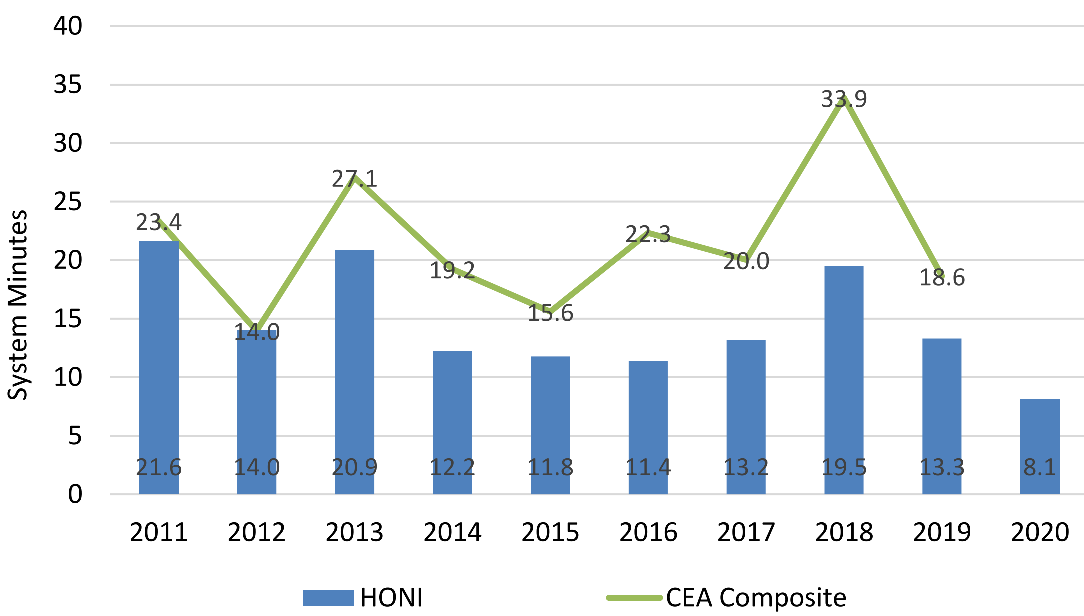


Figure 10: DP Unreliability Index, Hydro One vs CEA Composite

2.4.4.4.2 SYSTEM UNAVAILABILITY METRIC COMPARISONS

In this evidence, transmission system forced unavailability is divided into Unavailability of Transmission Lines and Unavailability of Transmission Station Equipment as shown in:

- Figure 11: Unavailability of Transmission Lines; and
- Figure 12: Unavailability of Major Transmission Station Equipment.

This division is based on the different characteristics of the equipment.

Transmission Station equipment includes power transformers and circuit breakers, etc. The Unavailability measure represents the extent to which the major transmission equipment is not available for use within the system due to forced outages. The detailed description of this measure is provided in Attachment 3. Figures 11 and 12 illustrate the historical annual performance of Hydro One lines and station equipment in comparison to the CEA Composite five-year moving average performance of all the CEA member utilities. CEA 5-year moving average values for 2020 will be available in late Q4 2021.

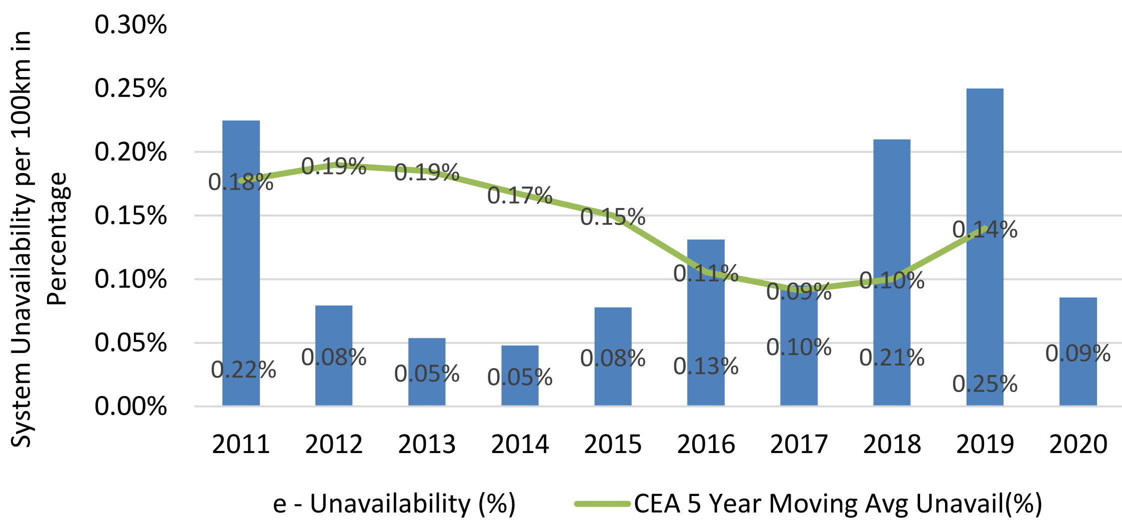


Figure 11: Unavailability of Transmission Lines

The Unavailability of Transmission Lines measure deteriorated in 2018 and 2019 due to a combination of factors including severe weather events, a fire at Middleport TS in April 2019 and a leak in an underground oil filled cable, which required significant repair time.

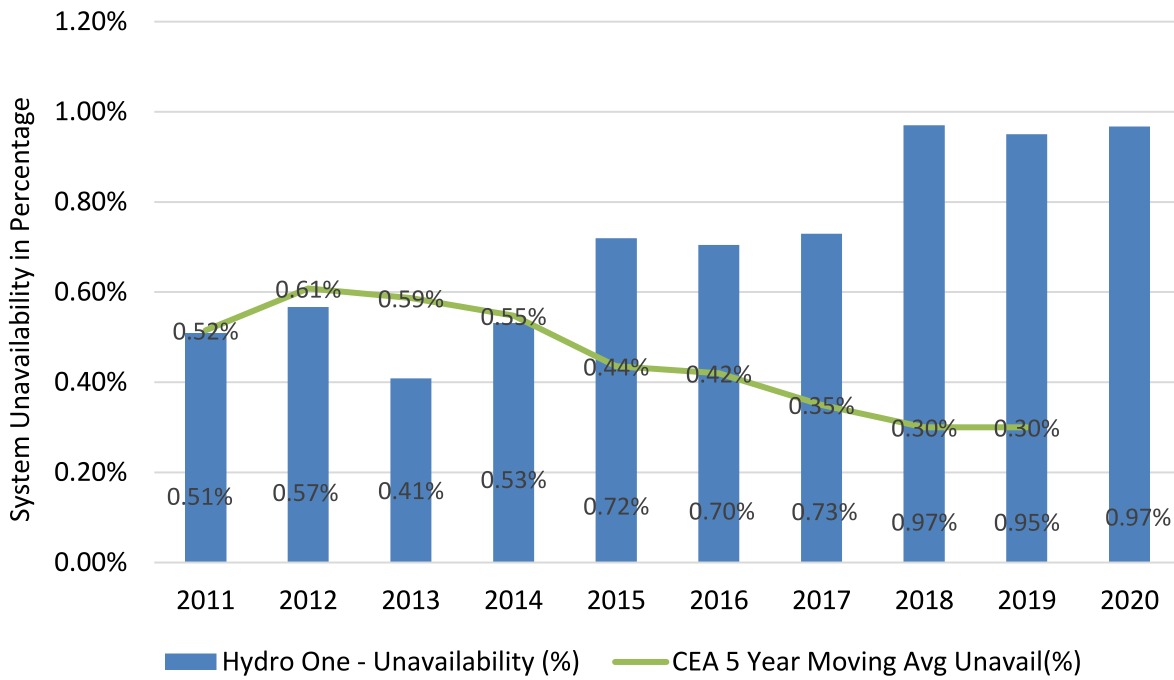


Figure 12: Unavailability of Major Transmission Station Equipment

Hydro One transmission station equipment recently has shown higher system unavailability when compared to previous years' performance. This deterioration of this measure is due to a combination of factors that include:

1. Transformers that were about to be retired 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, i.e. a planned outage, the total duration of the projects is treated as forced rather than planned outage and contributes to equipment unavailability even 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.

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 are made to preserve the performance of critical asset groups by evaluating assets at both an individual asset level and at a station or line level. This prioritizes investment needs to identify the most effective reliability alternative. This approach helps preserve overall system reliability.

2.4.5 DELIVERY POINT PERFORMANCE OUTLIERS

DP performance is evaluated according to Hydro One’s Customer DP Performance (CDPP) Standards that were approved by the OEB in EB-2002-0424. The performance standard is used as a trigger to initiate assessment and follow up with affected customers to:

- Determine the root cause of unreliability;
- Perform technical and financial evaluations; and
- Decide on remedial action to improve reliability.

Figure 10 is a summary of the transmission Group and Individual Outliers as determined by the CDPP Standards criteria from 2007, the first year of formal CDPP reporting.

Based on CDPP Standards, a DP is identified as a group outlier in a given year when its most recent 3-year average interruption frequency or duration exceeds the minimum performance threshold for customers in its load class as defined by the group outlier standard.[7] 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 Figure 13, 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 same year.

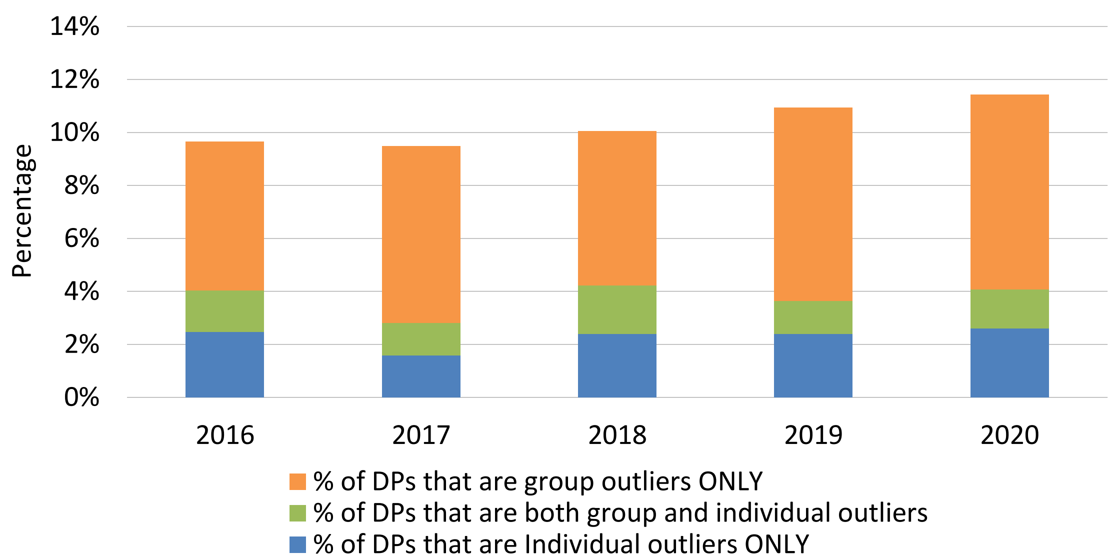


Figure 13: Transmission Load DP Outlier Percentage

[7] 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.

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 the total population of its DPs. 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, given its extremely good individual outlier (historical) baseline, recent isolated events may drive a performance decline resulting in it temporarily becoming an individual outlier. In most cases, such DPs return to non-outlier status in the following year without the need for any incremental investment. Hydro One takes this possibility into consideration in 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

TSP FIRST NATIONS RELIABILITY PERFORMANCE

2.4.A.1 INTRODUCTION

All First Nations communities are connected to the Hydro One distribution system and their reliability is discussed in Exhibit A-07-02, Attachment 1.[1] The distribution lines servicing First Nations communities are supplied from 69 transmission lines, four direct connections to high voltage stations busses and 71 delivery points as of the end of 2020. This attachment to TSP 2.4 discusses the reliability associated with these transmission lines and delivery points, and actions Hydro One is undertaking to improve reliability.

This attachment begins with a discussion of First Nations transmission reliability on both the Northern and Southern portion of the system. This is followed by a summary of the actions that Hydro One Transmission is planning over the 2023-2027 period to improve transmission reliability for First Nations.

2.4.A.2 RELIABILITY PERFORMANCE

The reliability performance of the transmission delivery points that serve distribution connected First Nations communities is shown in Table 1 below. As mentioned in TSP Section 2.4 the reliability performance of individual delivery points is 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 a dual line supply and smaller loads were connected with a single line supply.

[1] Exhibit A-07-02, Attachment 1 also describes how Hydro One engaged with First Nations Chiefs and/or their representatives on their electricity needs, general preferences and views on Hydro One's investment plan.

Table 1 - First Nations Reliability – Northern and Southern Sub-Systems

Transmission System - Northern Sub-System (2016-2020 Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (Interruptions minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions/ Tx Connection)
First Nations	45	215.1	4.40
Transmission System - Southern Sub-System (2020 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (Interruptions minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions/ Tx Connection)
First Nations	26	21.2	0.86

Generally, the majority of delivery points in the Northern sub-system are served by single circuit 115 kV lines that travel long distances through heavily treed areas. In 2020, the northern system serving First Nations contained 40 single circuit supplied delivery points and five dual circuit supplied delivery points. Broken branches or uprooted trees are easily blown into the line causing an outage. In addition, because of the long distances, rugged terrain and extreme weather conditions, repairs for forced outages on the Northern system tend to take longer to accomplish.

In contrast, most Southern sub-system delivery points are served by dual circuits at 230kV. In the southern system there were five single circuit supplied delivery points and 21 multi-circuit supplied delivery points serving First Nations. The predominance of dual circuit supply means most lines or station equipment outages do not result in customer interruptions. In addition, the shorter distances and more extensive road system allow repairs to occur more quickly on the Southern sub-system.

Figure 1 below shows the reliability performance in 2020 of the transmission delivery points that serve First Nations in both the Northern and Southern sub-systems. The red line on the map illustrates the boundary between the two sub-systems. Of the 45 delivery points that serve distribution connected First Nations communities in Northern sub-system, seven are reliability outliers for both duration and frequency measures.

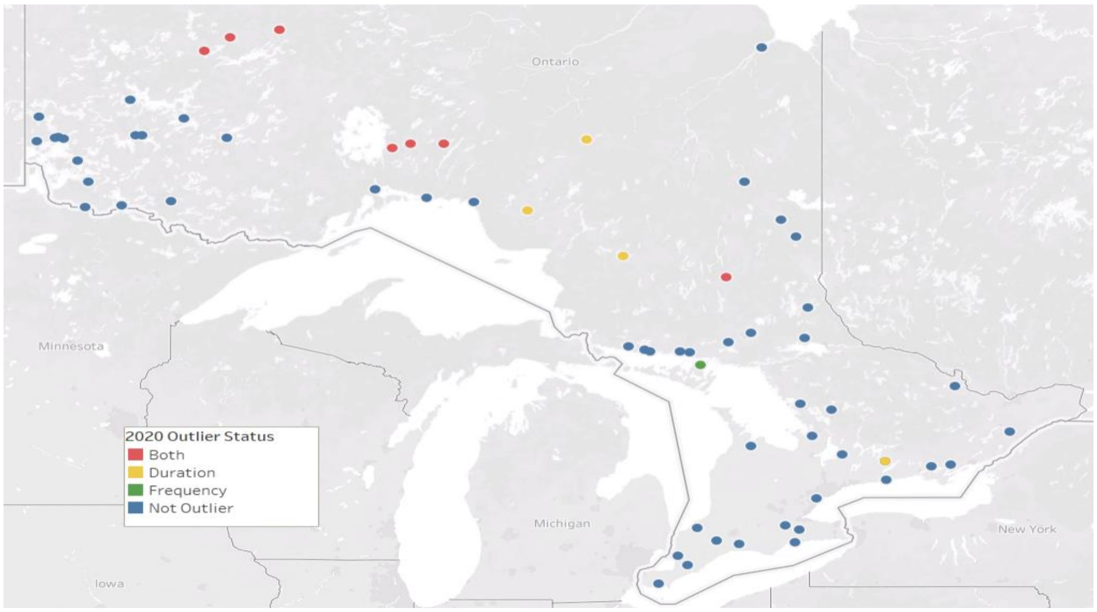


Figure 1: First Nations 2020 Outlier Status

2.4.A.3 WORK ADDRESSING FIRST NATIONS RELIABILITY

This section discusses work that Hydro One is undertaking to address First Nations reliability issues.

The seven delivery points that are outlier for both duration and frequency in the Northern sub-system are served by the 115kV circuits T61S, A4L, and E1C transmission lines. Hydro One is currently refurbishing the T61S circuit and the work is expected to be complete by Q2 2023 (See TSP Section 2.11, T-SA-02). Hydro One is also planning to refurbish the A4L and the E1C circuits during the current plan period (See TSP Section 2.11, T-SR-13C and T-SR-13L). In addition, work by Wataynikaneyap LP to construct an approximately 300 km single circuit 230 kV line running from the Dinorwic area to the Pickle Lake area will create a loop with the E1C line, which will allow Hydro One to perform repairs on E1C and improve the reliability to delivery points in this area by establishing a second supply.

In addition, Hydro One is continuing its efforts to refurbish other transmission lines and stations that are in poor condition and pose a risk to the reliability performance of delivery points serving First Nations communities over the 2023-2027 period. Apart from the work on the T61S, A4L and the E1C transmission lines mentioned above, the System Renewal investments proposed include the refurbishment of portions of two double circuit transmissions lines A4H/A5H (TSP Section 2.11, T-SR-I3.10) and M6E/M7E (TSP Section 2.11, T-SR-I3.9), two single circuit transmission lines N5K (TSP Section 2.11, T-SR-13.14) and S2N (TSP Section 2.11, T-SR-13.15) and two stations Marathon TS (TSP Section 2.11, T-SR-01.11) and Wawa TS (TSP Section 2.11, T-SR-01.12).

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 May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the 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.

[1] A Delivery Point (DP) is defined as a point of connection between a transmitter’s transmission facilities and a customer’s facilities.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

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 load being served at the delivery point; and
- 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 unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized in Sections 2.1.

2.1 PERFORMANCE STANDARDS BASED ON SIZE OF LOAD BEING SERVED: GROUP CDPP STANDARDS

The CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[2] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1.

[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/yr)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (min/yr)	89	360	22	140	11	55	5	25

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[3] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system. Included in this category of excluded events are the 1998 ice storm and the 2003 blackout.

2.1.1 CRITERIA FOR MINIMUM STANDARD PERFORMANCE TO IDENTIFY PERFORMANCE OUTLIERS FOR GROUP CDPP STANDARDS

The minimum CDPP standards of performance, for each of the four load groups or bands, are used as triggers by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the minimum CDPP Standard for the delivery point of the load size group or band (referred to as a performance outlier or outlier) or when a delivery point customer indicates that analysis is required. When an outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate technical and financial

[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.

evaluations in consultation with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability.

2.1.2 PERFORMANCE STANDARDS TO MAINTAIN HISTORICAL DELIVERY POINT PERFORMANCE INDIVIDUAL CDPP STANDARDS

In this component, the CDPP Standards are intended to maintain the reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1). In order to identify customer delivery points 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 delivery point based on that delivery point's historical 1991-2000 average performance, plus one standard deviation (the "historical baseline"). The historical baselines exclude 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 trend of the measure, such as the 1998 Eastern Ice Storm, the 2003 Northeast Blackout, the 2013 GTA flood and 2018 Ottawa area Tornado. Also, for delivery points that came into service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.1.3 CRITERIA FOR MINIMUM STANDARD PERFORMANCE TO IDENTIFY PERFORMANCE OUTLIERS FOR INDIVIDUAL CDPP STANDARDS

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered to be a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's 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 what was designed originally. These costs include appropriate asset sustainment costs, on-going 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 the 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 that was inherent to the original system design or configuration of supply.

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 transformation and/or transmission line connection revenue[4] associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be contributed by affected delivery point 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.

[4] 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 these investments is to be consistent with the TSC, specifically:

1. Hydro One will not attribute the 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 is the only portion of the technical and financial evaluation that is to be included as part of 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 of the costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost sharing arrangements are to be detailed in a connection and cost recovery agreement with the affected customers.

2.2 PROCESS TIMELINES TO ADDRESS PERFORMANCE OUTLIERS

The process and associated timelines that will be followed to address performance outliers – both for Group and Individual outliers – and to determine the preferred course of action, are provided in Figure 1 and Table 2.

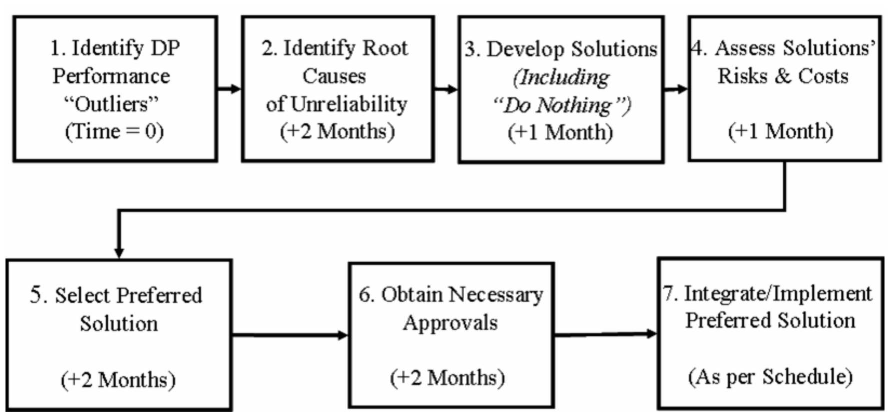


Figure 1: Performance Outlier Process Map

Table 2 - Performance Outlier Process

Step	Timeline	Action
1	0	Hydro One identifies, annually, delivery point performance "outliers" for both Group and Individual standards. Hydro One will notify customers that are supplied from these performance outlier delivery points and solicit their feedback/issues/ concerns on their reliability of supply.
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. the work to restore and sustain the inherent reliability performance of the existing assets to what was designed originally; and 2. for Group Performance outliers, the additional capital improvements required to improve the performance of an outlier to within standard and beyond what was designed originally. 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 (step 2) above. Hydro One will present these costs to customers for their review and assessment.
5	< 2 months	Hydro One and customers select the preferred option and where appropriate customers state their intention on whether to proceed with capital improvements that involve customer contributions identified in option (step 2) above.
6	< 2 months	Hydro One and customers obtain the necessary approvals to proceed with the preferred solutions to address performance outliers.
7	Agreed to Schedule	Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

When Hydro One completes work to restore delivery point performance to standard, it continues to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then Hydro One will review the work that has taken place and will identify corrective action. Hydro One will not, as a practice, wait another three years and start a new technical and financial evaluation. Hydro One reviews and identifies customer delivery point performance annually, regardless of the investment history.

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DESCRIPTION OF THE RELIABILITY MEASURES

DELIVERY POINT

The delivery point is the point of supply where the energy from the Bulk Electricity System (115 kV and above) is transferred to the Distribution System or the 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, this point is generally taken as the interface between utility-owned equipment and the customer's equipment.

FORCED INTERRUPTION

Is a delivery point interruption due to a disconnection as a result of 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 are interruptions are generally restored by automatic reclosure facilities and are of a very short duration (of the order of 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 is an indicator of the average number of interruptions that a customer experienced and is presented as interruptions per delivery point per year. It is expressed mathematically as:

Average Frequency of Delivery Point Interruptions

Where:

- Mi is the total number of momentary interruptions experienced at Delivery Point i in a given year.
- Si 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 for a given year.

The frequency of power supply interruptions and indicators that track such performance are universally used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption frequency indicator. Additionally, the Canadian Electricity Association (CEA) tracks the frequency of delivery point interruptions among the CEA transmission member utilities.

Furthermore, the average sustained and momentary frequency of delivery point interruptions can be presented separately.

AVERAGE DURATION OF DELIVERY POINT INTERRUPTIONS

Average Duration of Delivery Point Interruptions is the average time that customers are interrupted from transmission system and presented as minutes per delivery point per year. It is expressed mathematically as:

Average Duration of Delivery Point Interruptions $= \frac{\sum_{i=1}^{N} (\mathrm{D}_i)}{N}$

$$= \frac{\sum_{i=1}^{N} (M_i + S_i)}{N}$$

Where:

- Di 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 for a given year.

The duration of delivery point interruptions and indicators that track such performance are universally used in other regulatory jurisdictions. Transmission service providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption duration indicator. Additionally, the CEA tracks the duration of delivery point interruptions among the CEA transmission member utilities.

UNSUPPLIED ENERGY

Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. This measure is defined as 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.
- Pk is the system peak load in the year, expressed in MW.
- N is the equivalent total number of delivery points for a given year.

The unit of the measure of normalized unsupplied energy is expressed in "system minutes". Transmission companies in Canada, the U.S., 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 system level or sub-categorized as (1) Transmission Line Unavailability, and (2) Station Equipment Unavailability, consistent with the CEA reliability benchmarking programs.

These indicators are expressed mathematically as:

Total System Unavailability $= \left(\dfrac{\sum_{i=1}^{N_M} F_{Mi}}{\mathrm{T_M}} \right) \mathrm{x}\, 100\%$

Where:

- F_{Mi} is the annual forced outage duration in hours for Major Transmission Equipment, including both station equipment and transmission lines, Mi.
- T_M is the inventory (expressed in hours) of all In-service Major Transmission Equipment, including both station equipment and transmission lines.
- N_M is the total number of in-service major transmission equipment, including station equipment and transmission lines.

(1) Transmission Line Unavailability $= \left(\dfrac{\sum_{i=1}^{N_L} F_{Li}}{\mathrm{T_L}} \right) \mathrm{x}\, 100\%$

Where:

- F_{Li} is the annual forced outage duration in hours due to transmission line-related outages of circuit Li.
- 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 Si.
- T_S is the inventory (expressed in hours) of all In-service Major Transmission Station Equipment
- N_S is the total number of in-service major transmission station equipment.

These indicators track the extent to which the transmission system, including transmission circuits and substation equipment, is not available for use. These indicators are focused on the aspect of transmission service within Hydro One's control. It also puts the impact of outages in context with the availability of the transmission system as a whole and expresses the impact of outages in a single, easily understood indicator. Transmission companies in Canada, U.S., and in Europe use indicators of this type to assess transmission system reliability.

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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.

2.5.2 TRANSMISSION SCORECARD

In the 2020-2022 transmission rate application (EB-2019-0082), the OEB approved Hydro One's Transmission Scorecard[1] with one revision approved in the OEB's final Order.[2] The Transmission Capital Accomplishment Index (TCAI) revised Hydro One's proposed capital accomplishment measure to provide an expanded focus on System Renewal. Hydro One will continue to use the measures approved in the prior application and has presented the prior application's targets up to 2022 (the Bridge year). In some instances the methodology to establish some targets has been revised and reflected below (e.g. Overall Customer Satisfaction) and updated performance expectations.

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.

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[1] EB-2019-0082, Decision and Order, April 23, 2020, pp. 55-56.
[2] EB-2019-0082, Revenue Requirement and Charge Determinant Order, July 16, 2020, p. 11.

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019	2020	Trend	Targets 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	9.7	9.5	10.1	10.9	11.4	▲	13.0	12.0	11.7	11.5	11.3	11.0	10.8	10.6	10.4	10.2
	Customer Satisfaction	Overall Customer Satisfaction (% Satisfied)	78	88	90	87	83	▲	86	88	88	88	88	88	88	88	88	88
		Satisfaction with Outage Planning Procedures (% Satisfied)	89	94	85	84	71	▼	85	86	86	87	87	85	85	85	85	85
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	1.1	1.2	1.1	0.8	0.9	▼	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	0.46	0.65	0.83	0.59	0.50	►	0.58	0.55	0.54	0.53	0.52	0.56	0.55	0.54	0.52	0.51
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	0.33	0.47	0.50	0.43	0.40	▲	0.53	0.49	0.48	0.48	0.47	0.43	0.42	0.41	0.41	0.40
		T-SAIDI (Ave minutes of interruptions per Deliver Point)	80.8	42.8	70.0	38.9	61.3	▼	46.5	35.4	34.7	34.0	33.3	32.6	31.9	31.3	30.7	30.1
		System Unavailability (%)	0.70	0.69	0.71	0.89	0.83	▲	0.42	0.48	0.47	0.47	0.46	0.62	0.61	0.60	0.59	0.58
		Unsupplied energy (minutes)	11.4	13.2	19.5	13.3	8.0	▼	12.6	9.8	9.6	9.4	9.2	9.0	8.8	8.6	8.4	8.2
	Asset & Project Management	Transmission System Plan Implementation Progress (%)	100	94	99	101	101	▲	100	100	100	100	100	100	100	100	100	100
		CapEx as % of Budget	105	100	97	99	104	▼	100	100	100	100	100	100	100	100	100	100
		OM&A Program Accomplishment (composite index)	99	108	107	88	93	▼	100	100	100	100	100	100	100	100	100	100
		Transmission Capital Accomplishment Index (TCAI) - (%)					101				100	100	100	100	100	100	100	100
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	8.6	7.9	7.7	7.4	7.9	▼	7.7	7.3	7.8	7.9	7.7	7.9				
		OM&A per Gross Fixed Asset Value (%)	2.5	2.3	2.3	1.9	2.1	▼	2.2	1.8	1.8	1.7	1.6	1.9				
		Line Clearing Cost per kilometer ($/km)	1,966	2,100	2,797	3,817	3,368	▲	2,295	2,295	2,264	2,200	2,175	2,784	2,854	2,925	2,998	3,073
		Brush Control Cost per Hectare ($/Ha)	1,542	1,356	1,539	1,924	1,538	▲	1,625	1,625	1,620	1,630	1,608	1,628	1,669	1,711	1,754	1,798
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	100	100	100	100	100	►	100	100	100	100	100	100	100	100	100	100
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %	100	100	100	100	100	►	100	100	100	100	100	100	100	100	100	100
		End-of-Life Right-Sizing Assessment Expectation		Met	Met	Met	Met		Met	Met	Met	Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.20	0.13	0.12	0.20	0.28											
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.43	1.47	1.53	1.52	1.50											
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.19	8.78	9.00	N/A	8.52											
		Profitability: Regulatory Return on Equity — Achieved	10.02	9.03	11.08	9.53	9.29											

Legend: 5-year trend (or all available years)
▲ up ▼ down ► flat
Hydro One target met Hydro One target not met

Figure 1: Electricity Transmitter Scorecard and Targets – Hydro One Networks Inc.

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 2023-2027 rate period.

2.5.2.1 CUSTOMER FOCUS MEASURES

2.5.2.1.1 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.

2.5.2.1.1.1 CUSTOMER DELIVERY POINT PERFORMANCE, STANDARD OUTLIERS AS PER CENT OF TOTAL DELIVERY POINTS

Performance Category	Measures	Description
Service Quality	Customer Delivery Point Performance, Standard outliers as % 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 2020 increased by 0.5% compared to 2019, mainly due to a greater number of Equipment and Foreign caused interruptions. Hydro One's average performance over the past five years (2016-2020) was 10.3% and the performance trend is indicating an increase in the percentage of delivery point outliers. Hydro One's performance was better than target in each of the years 2018-2020, as shown in the table below.

Table 1 - CDPPS Outliers as Percentage of Total Delivery Points (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	13.0	12.0	11.7	
Actual	9.7	9.5	10.1	10.9	11.4	▲

TARGETS

Over the 2023-2027 period, Hydro One is targeting a declining percentage of outliers to 10.2% in 2027, reflecting an improvement relative to the 2016-2020 average.

Table 2 - CDPPS Outlier Targets (%)

	2021	2022	2023	2024	2025	2026	2027
Target	11.5	11.3	11.0	10.8	10.6	10.4	10.2

2.5.2.1.2 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. The results for these measures demonstrate a continuing high level of satisfaction.

2.5.2.1.2.1 OVERALL CUSTOMER SATISFACTION IN CORPORATE SURVEY (PERCENT SATISFIED)

Performance Category	Measures	Description
Customer Satisfaction	Overall Customer Satisfaction, corporate 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 a professional research company on behalf of Hydro One. It measures the opinions of customers and seeks to uncover perceptions of how well

Hydro One is meeting 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 2012 to 2020 period, average customer satisfaction was 83%. Between 2017 and 2019, overall customer satisfaction reached historically high levels (between 87% and 90%). In 2020, overall satisfaction remained high at 83%, but decreased from previous years as shown in Table 3. While 100% of the Transmission End Users were satisfied, the satisfaction rate for LDCs was 73%. Hydro One identified the following reasons to explain this decrease:

- Hydro One sent email invitations and reminders to all of its LTX customers to participate in the annual CSAT survey. In 2020, despite extensive efforts to engage customers, the participation rate dropped from 55% (109 customers surveyed) to 24% (47 customers surveyed). This lower participation rate introduced greater uncertainty around the 2020 results.
- Throughout 2020, Account Executives were limited in their ability to visit their customers due to the COVID-19 pandemic and had to establish new ways of communication. It is likely that these changes negatively affected customer's perception of the level of service they received in comparison to previous years.
- 57% of customers in this segment reported being affected by the COVID-19 pandemic, resulting in changes to their business needs and negative financial impacts. Greater stress caused by factors outside of Hydro One's control are likely to have influenced their satisfaction levels with every aspect of their business.

Table 3 - Overall Customer Satisfaction (% Satisfied)

	2016	2017	2018	2019	2020	Trend
Target	-	-	86	88	88	
Actual	78	88	90	87	83	▲

Hydro One is committed to improving satisfaction levels for LTX customers. Considerable focus will be placed on our 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.

TARGETS

For the 2023-2027 period, Hydro One will target 88% overall customer satisfaction. This target reflects the company's aim to deliver consistent, high-quality customer service, and represents a challenging and reasonable level in long-term customer satisfaction when compared to the level achieved over recent years.

Table 4 - Overall Customer Satisfaction Targets

	2021	2022	2023	2024	2025	2026	2027
Target	88	88	88	88	88	88	88

2.5.2.1.2.2 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.

Since 2018, Hydro One has been measuring satisfaction with the outage planning procedures among LTX customers as part of the annual customer satisfaction (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.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In previous rate filings, satisfaction with outage planning procedures was reported based on a transactional OGCC survey, which has since been discontinued. Due to this change in methodology, results for the period before 2018 are not comparable with those for 2018 and beyond. Going forward, targets have been based on the new methodology, as described below. Historical results are presented in the table below.

Table 5 - Satisfaction With Outage Planning Procedures (% Satisfied)

	2016	2017	2018	2019	2020	Trend
Target	-	-	85	86	86	
Actual	89*	94*	85	84	71	▼

**Previous methodology*

In 2019, the satisfaction rate among LTX customers with the outage planning process was high at 84%. In 2020, however, during the COVID-19 pandemic, satisfaction decreased to 71%. Respondents identified two main areas for improvement: more advance notice and better communication of details. Hydro One identified the following explanations for this drop:

- Hydro One sent email invitations and reminders to all of its LTX customers to participate in the annual CSAT survey. In 2020, despite extensive efforts to engage customers, the participation rate dropped from 55% (109 customers surveyed) to 24% (47 customers surveyed). This introduced greater uncertainty around the 2020 results.
- Throughout the year, COVID-related restrictions limited the ability of Account Executives to visit their customers. Account executives had to establish new ways of communication. Owing to the inability to meet face to face, discussions about the outage planning process likely were not as detailed and well understood as they had been in the past.
- 57% of customers in this segment reported being affected by the COVID-19 pandemic, resulting in changes to their business needs and negative financial impacts. Greater stress caused by factors outside of Hydro One's control is likely to have influenced their satisfaction levels with every aspect of their business.

TARGETS

Hydro One is working to improve its outage planning process for transmission-connected customers and is targeting 85% satisfaction with outage planning procedures over the 2023 - 2027 period. This target represents a challenging and reasonable level in long-term customer satisfaction for outage planning.

Table 6 - Outage Planning Procedures Targets

	2021	2022	2023	2024	2025	2026	2027
Target	87	87	85	85	85	85	85

2.5.2.2 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.

2.5.2.2.1 SAFETY

2.5.2.2.1.1 RECORDABLE INJURY RATE (NUMBER OF RECORDABLE INJURIES/ILLNESSES PER 200,000 HOURS WORKED)

Performance Category	Measures	Description
Safety	Recordable Rate (Number 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 declined by approximately 90% over the past ten years. More importantly, 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 past five years (2016-2020), Hydro One's average Recordable Injury Rate was 1.0 incident per 200,000 hours worked, and it declined by approximately 20% over this period, as presented in the table below. Importantly, the Recordable Injury Rate continues to be below 1.0, which is considered industry-leading among peer utilities.

Table 7 - Recordable Injury Rate (# Recordable Injuries/Illness per 200K Hours Worked)

	2016	2017	2018	2019	2020	Trend
Target	-	-	1.1	1.1	1.1	
Actual	1.1	1.2	1.1	0.8	0.9	▼

Hydro One’s success 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. We continue to adopt the philosophy that a safe utility is also an efficient utility (i.e., focusing on effective job planning, communication among team members, empowering employees, and creating a culture of accountability). Furthermore, Hydro One continues to focus on improvements through the Journey to Zero forums, ensuring the Health, Safety and Environment Management System is effective through regular leadership reviews and audits; ongoing training and development; regular safety meetings; workplace safety observations and employee communications; and proactive engagement with employees.

TARGETS

To support an unwavering commitment to safety, Hydro One established an employee-led Safety Improvement Team. As part of the strategy to become the safest and most efficient utility, the Safety Improvement Team developed recommendations to build a strong culture and bring an end to serious injuries and fatalities. These recommendations have been incorporated into Hydro One's multiyear safety implementation plan, which will be executed over the next several years.

Over the 2023-2027 period, Hydro One aims to maintain industry-leading safety performance with a Recordable Injury Rate of less than 1.0 recordable injury/illness per 200,000 hours worked, as presented in the table below.

Table 8 - Recordable Injury Rate Targets

	2021	2022	2023	2024	2025	2026	2027
Target	1.0	0.9	0.9	0.9	0.9	0.9	0.9

Hydro One expects continued improvements over the next few years, with a focus on reducing and eliminating life altering injuries and fatalities. The following safety initiatives are underway to reduce high-impact injuries: using recordable incidents as a learning opportunity; improving control-effectiveness to reduce risk; improving the effectiveness of work safety observations; conducting in depth investigations with meaningful corrective actions; and placing a greater focus on Human Success. In essence, the Human Success 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.

Hydro One is working together, as one company, to eliminate serious injuries, and each member of the team has a role to play in bringing everyone home safely, every day.

2.5.2.2.2 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.[3] Extraordinary events are those like the 1998 Ice Storm or the 2003 Northeastern Blackout 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, Hydro One excludes major events from its reporting of Transmission Scorecard measures.[4] 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. 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.

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[3] 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.
[4] If an event meets the threshold for an extraordinary event, it is not also considered as a major event to avoid double counting.

2.5.2.2.2.1 T-SAIFI-S

Performance Category	Measure	Description
System Reliability	T-SAIFI-S (Sustained delivery point Interruption frequency) (Average # of power interruptions to a customer (delivery point))	Transmission System Average Interruption 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.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

The average number of sustained interruptions per Delivery Point in 2020 was 0.50, a decrease in the index value of 0.09 or about 14% compared to 2019, primarily due to fewer weather and equipment caused interruptions. Performance in 2018 was affected by an unusually high number of weather events and more equipment failures than average.

Hydro One's average performance over the past five years (2016-2020) was 0.61, and the performance trend is relatively flat during the past five years (see Figure 2).

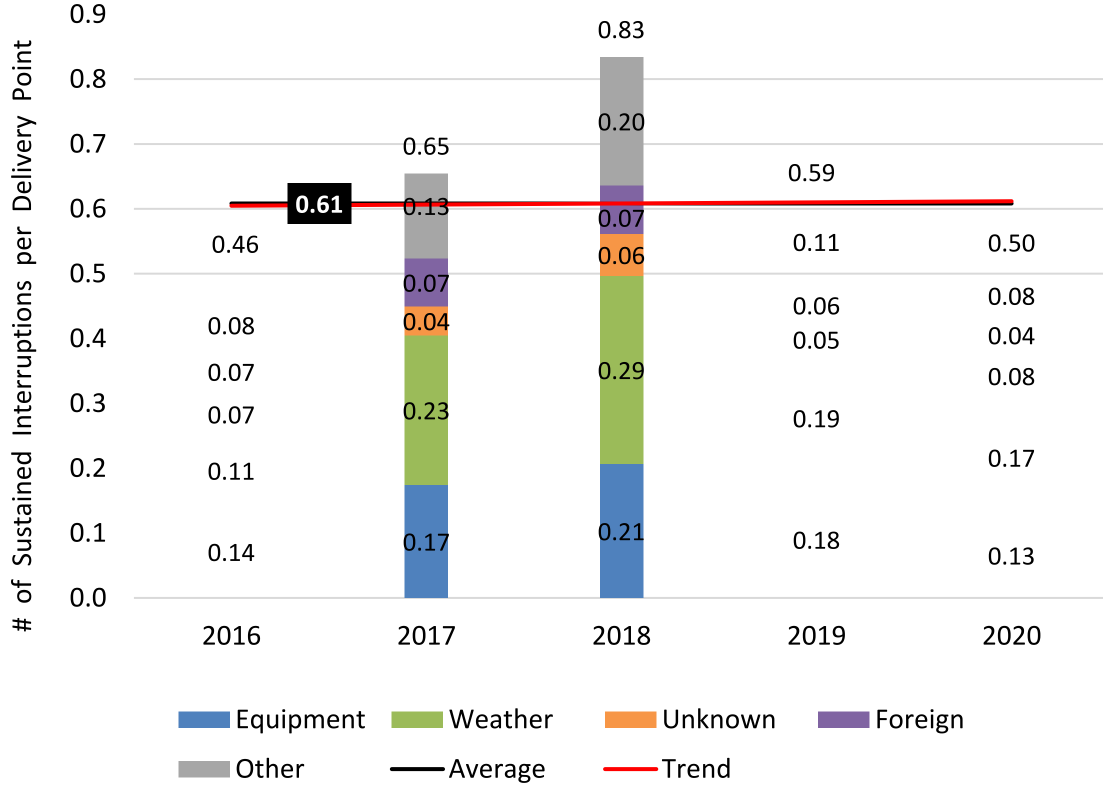

Figure 2: Transmission System Average Interruption Frequency Index – Sustained

TARGETS

Over the 2023-2027 period, Hydro One aims to improve against its historical average, targeting 0.51 in 027 for T-SAIFI-S. Targets have been presented in the table below.

Table 9 - T-SAIFI-S Targets

	2021[5]	2022[5]	2023	2024	2025	2026	2027
Target	0.53	0.52	0.56	0.55	0.54	0.52	0.51

[5] Targets for 2019 to 2022 T-SAIFI-S reflect levels presented in EB-2019-0082, and contain a computational error. Correcting for this error would result in a 0.05 increase in each year.

2.5.2.2.2.2 T-SAIFI-M

Performance Category	Measure	Description
System Reliability	T-SAIFI-M (Momentary delivery point interruption frequency) (Average # of power interruptions to a customer (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 2020 was 0.40, a decrease in the index value of 0.03 or about 8% compared to 2019, primarily due to fewer weather caused interruptions.

Hydro One’s average performance over the past five years (2016-2020) was 0.43 interruptions per Delivery Point, and the performance trend is slightly degrading, indicating an increase in the average number of momentary interruptions per Delivery Point (see Figure 3).

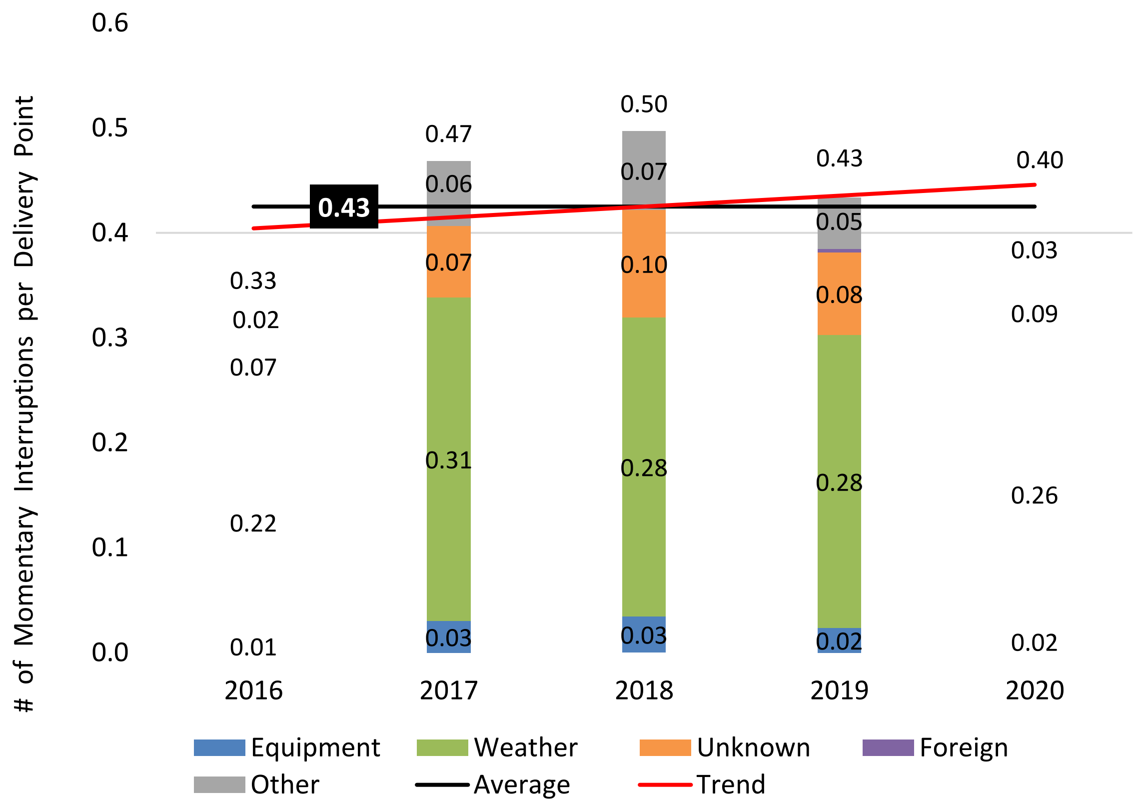

Figure 3: Transmission System Average Interruption Frequency Index – Momentary

TARGETS

Over the 2023-2027 period, Hydro One aims to improve against its historical average, targeting 0.40 in 2027 for T-SAIFI-M. Targets have been presented in the table below.

Table 10 - T-SAIFI-M Targets

	2021[6]	2022[6]	2023	2024	2025	2026	2027
Target	0.48	0.47	0.43	0.42	0.41	0.41	0.40

[6] Targets for 2019 to 2022 T-SAIFI-M reflect levels presented in EB-2019-0082, and contain a computational error. Correcting for this error would result in a 0.03 decrease in each year.

2.5.2.2.2.3 T-SAIDI

Performance Category	Measure	Description
System Reliability	T-SAIDI (Delivery point interruption duration) (Average # minutes of power interruptions to a customer (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 2020 was 61.3 minutes, an increase of 22.3 minutes or about 57% compared to 2019. The result in 2020 was primarily driven by two equipment outages:

- August 20: T7M (Otter Rapids SS – Moosonee SS) forced from service since the line conductor was vandalized and about to fail. This resulted in an interruption of approximately five days to each of two delivery points. The duration of the interruption was attributable to the remote location and a decision not to incur the cost of a weekend repair given that both delivery points served by the line had backup generation with ample fuel supplies.
- November 1: 115 kV Circuit K2 (radial from Kirkland Lake TS) tripped from a broken cross-arm. This resulted in an interruption of approximately three days to each of two delivery points.

Hydro One’s average performance over the past five years (2016-2020) was 58.7 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.

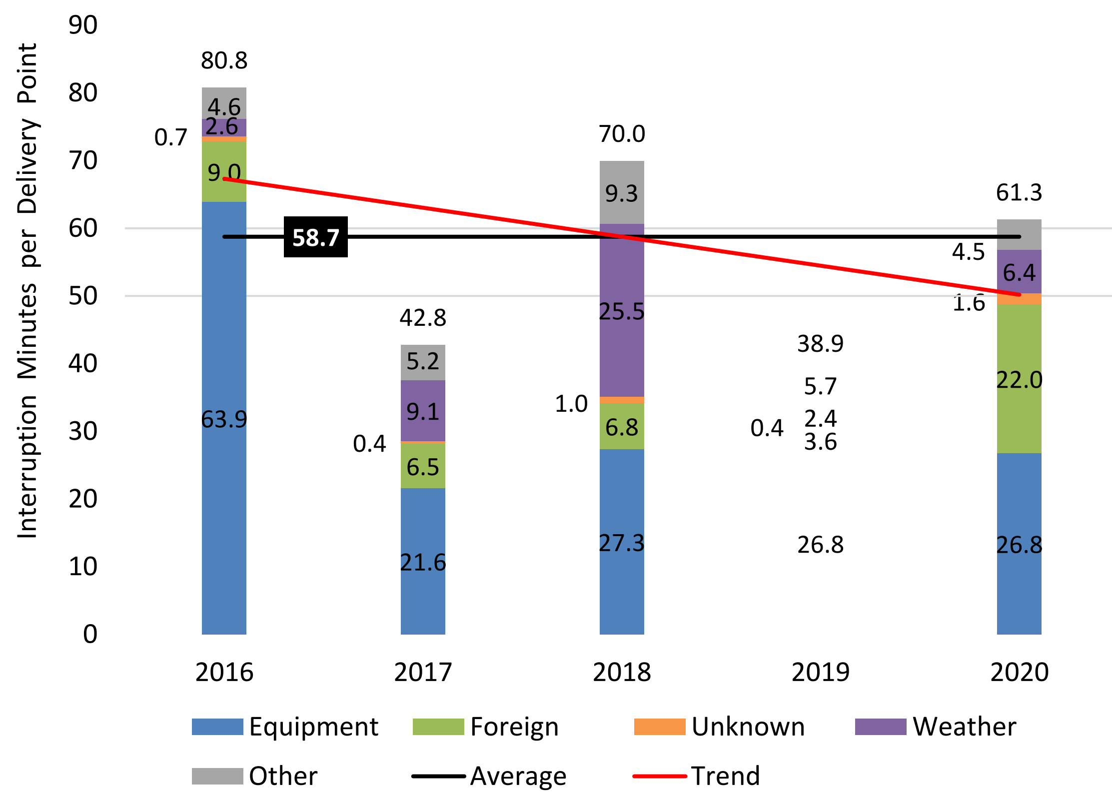

Figure 4: Transmission System Average Interruption Duration Index (Minutes)

TARGETS

Over the 2023-2027 period, Hydro One aims to improve T-SAIDI performance annually, targeting 30.1 minutes in 2027, based on the 2019 target with a 2% annual improvement per year. Targets have been presented in the table below.

Table 11 - T-SAIDI Targets

	2021	2022	2023	2024	2025	2026	2027
Target	34.0	33.3	32.6	31.9	31.3	30.7	30.1

2.5.2.2.2.4 SYSTEM UNAVAILABILITY

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,[7] 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. This measure is specifically defined to enable comparison with all-Canada averages from all transmission utilities that participate in the Equipment Reliability Information System (ERIS) program of the Transmission Consultative Committee on Outage Statistics (T-CCOS) at the Canadian Electricity Association (CEA).

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

For 2020, System Unavailability was 0.83%, which is 0.06% lower than the 2019 result. System unavailability in 2020 was largely driven by long duration outages on reactive components (capacitor, reactor, SVC) and associated breakers. At two sites (St. Thomas TS and Coniston TS),

[7] Major station equipment includes: Transmission lines, High voltage cables, Breakers, Transformers, Shunt capacitor banks, Shunt reactors, Series capacitor banks and Static VAR Compensators.

equipment failed while the stations were in the process of being decommissioned. This equipment was left out of service because the equipment was being replaced and the load was already being supplied by other stations, however the failures met the definition of the System Unavailability measure and therefore were included. Historical System Unavailability is presented in the table below.

Table 12 - System Unavailability (% Time Unavailable)

	2016	2017	2018	2019	2020	Trend
Target	-	-	0.42	0.48[8]	0.47[8]	
Actual	0.70	0.69	0.71	0.89	0.83	▲

Hydro One's average System Unavailability over the past five years (2016-20) was 0.79% and the performance trend indicates a degradation in system unavailability over this period.

TARGETS

Over the 2023-2027 period, Hydro One aims to improve System Unavailability performance annually, targeting 0.58 in 2027 based on the updated 2019 target with a 2% annual improvement per year. Targets have been presented in the table below.

Table 13 - System Unavailability (% Time Unavailable) Targets

	2021[8]	2022[8]	2023	2024	2025	2026	2027
Target	0.47	0.46	0.62	0.61	0.60	0.59	0.58

[8] Targets for 2019 to 2022 System Unavailability reflect levels presented in EB-2019-0082, and are based on a prior methodology. The new methodology set the 2019 target based on the 40th percentile of the prior 5-years and targets an annual 2% reduction.

2.5.2.2.2.5 UNSUPPLIED ENERGY

Performance Category	Measure	Description
System Reliability	Unsupplied Energy (System Minutes)	Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point unplanned interruptions.

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 2020 was 8.0 system minutes, lower by approximately 5.3 minutes or about 40% compared to 2019 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 in the table below.

Table 14 - Unsupplied Energy (System Minutes)

	2016	2017	2018	2019	2020	Trend
Target	-	-	12.6	9.8	9.6	
Actual	11.4	13.2	19.5	13.3	8.0	▼

Hydro One’s average performance over the past five years (2016-20) was 13.1 system minutes of unsupplied energy and the performance trend is improving.

TARGETS

Over the 2023-2027 period, Hydro One aims to improve Unsupplied Energy performance annually, targeting 8.2 minutes in 2027 based on the 2019 target with a 2% annual improvement per year. Targets have been presented in the table below.

Table 15 - Unsupplied Energy (System Minutes) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	9.4	9.2	9.0	8.8	8.6	8.4	8.2

2.5.2.2.3 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.

2.5.2.2.3.1 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 sustainment, development, and operating 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

For 2020, the TSP implementation achieved 101% of the planned in-service capital expenditures. Hydro One's average performance over the past five years (2016-2020) was 99% and the trend has improved over time. Transmission System Plan Implementation Progress is presented in the table below.

Table 16 - Transmission System Plan Implementation Progress (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	100	100	100	
Actual	100	94	99	101	101	▲

TARGETS

Over the 2023-2027 period, Hydro One aims to improve against its five-year average, and complete 100% of the annual planned in-service additions.

Table 17 - Transmission System Plan Implementation Progress (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.2.3.2 CAPITAL EXPENDITURES AS PERCENT OF BUDGET

Performance Category	Measure	Description
Asset & Project Management	Capital Expenditures as % of Budget	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

For 2020, the company's capital expenditures were 104% of budget. The result in 2020 was primarily due to upgrades in critical data centre infrastructure, additional real estate costs and contract payments for the Lakeshore TS new station build project, increased material and construction costs on the Middleport ABCB project, additional accomplishment on the D6 - Des Joachims TS X Petawawa DS Transmission Line Refurbishment project relative to plan, and equipment failure and outage constraints that were experienced on the Hanmer TS project resulting in the advancement of this project. Additional detail can be found in the Transmission Capital Performance Report (TSP Section 2.9, Attachment 2) and General Plant Capital

Performance Report (GSP Section 4.9, Attachment 2). Capital expenditures as percent of budget is presented in the table below.

Table 18 - Capital Expenditures (% of Budget)

	2016	2017	2018	2019	2020	Trend
Target	-	-	100	100	100	
Actual	105	100	97	99	104	▼

Hydro One's average performance over the past five years (2016-2020) was slightly above budget (101%) and the trend has slightly improved over time.

TARGETS

Over the 2023-2027 period Hydro One aims to complete 100% of the annual planned Capital Expenditures.

Table 19 - Capital Expenditures (% of Budget) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.2.3.3 OM&A PROGRAM ACCOMPLISHMENT (COMPOSITE INDEX)

Performance Category	Measure	Description
Asset & Project Management	Operations, Maintenance, & Administration (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

For 2020, Hydro One’s OM&A Program Accomplishment was 93% of budget, compared to 88% in 2019. The increase between these two years is mainly due to an improvement in the accomplishment of power equipment preventive maintenance, and an increase in the volume of testing and retro-filling of PCB-contaminated equipment. OM&A Program Accomplishment as percent of budget is presented in the table below.

Table 20 - OM&A Program Accomplishment (% of Budget)

	2016	2017	2018	2019	2020	Trend
Target	-	-	100	100	100	
Actual	99	108	107	88	93	▼

Hydro One's historical five year average (2016-2020) was 99%, and reflects a downward trend. This is mainly due to the unique circumstances faced in 2019 and 2020, including a one-time deferral of maintenance in 2019 due to reprioritization of resources to respond to a high volume of demand work on overhead lines and power equipment, and the effects of the COVID pandemic in 2020, which necessitated the implementation of revised work practices to adhere to public health guidance, and resulted in a more restrictive environment for obtaining planned outages. Variances to plan in 2020 were the result of lower accomplishments for P&C maintenance, which is carried out in confined spaces, and vegetation management, which covers extended geographic territories.

TARGETS

Over the 2023-2027 period Hydro One aims to complete 100% of the OM&A program.

Table 21 - OM&A Program Accomplishment (% of Budget) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.2.3.4 TRANSMISSION CAPITAL ACCOMPLISHMENT INDEX (TCAI)

Performance Category	Measure	Description
Asset & Project Management	Transmission Capital Accomplishment Index (TCAI)	The TCAI composite index measure 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, 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.

The Transmission Capital Accomplishment Index (TCAI) was added to the Transmission Scorecard during the Draft Rate Order process in EB-2019-0082. It compares the weighted actual in-year accomplishment for significant Transmission Capital investments against the weighted budget. The TCAI covers seventeen components from the System Renewal category that represent 81% of the OEB-approved System Renewal program approved in EB-2019-0082.

TCAI includes project based component replacements such as transformers, breakers, protections and conductors as well as programmatic component replacements, including poles, shieldwire, insulators and, tower and foundation coating. This metric demonstrates Hydro One’s ability to complete the planned capital program within the approved budget for the System Renewal category. The TCAI measure is meant to be evaluated in the context of other information presented in the TSP, including the Transmission Capital Performance Report (see TSP Section 2.9, Attachment 2).

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

For 2020, Hydro One’s TCAI value was 101. As this is the first year this measure has been used, there is no historical comparison. Details on System Renewal projects and programs investments completed can be found in the Transmission Capital Performance Report (see TSP Section 2.9, Attachment 2).

Table 22 - TCAI (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	-	-	100	
Actual	-	-	-	-	101	-

TARGETS

As this measure has only been in place for one year, Hydro One is not proposing any changes to the recently approved targets and will continue to target 100%.

Table 23 - TCAI (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.2.4 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).

2.5.2.2.4.1 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 2020 was 7.9%, or 0.5% higher compared to 2019, due to higher OM&A and capital expenditures. Higher OM&A as a result of OPEB costs and COVID-19 expenditures made up 0.2% and the remaining 0.3% was due to higher capital spending than budget. 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 (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	7.7	7.3	7.8	
Actual	8.6	7.9	7.7	7.4	7.9	▼

Hydro One's average performance over the past five years (2016-20) was 7.9%, and performance is moderately lower over the period, mainly due to required reinvestment and maintenance of gross fixed assets.

TARGETS

For 2023, Hydro One is targeting a ratio of 7.9%. For OM&A measures, Hydro One is not forecasting targets beyond the 2023 test year used to establish OM&A funding because OM&A levels during the remainder of the test period will be determined through the application of the Custom IR framework. Hydro One will continue to strive to work within the OEB-approved OM&A budget.

Table 25 - Total OM&A and Capital per Gross Book Value of In-Service Assets (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	7.9	7.7	7.9				

2.5.2.2.4.2 OM&A PER GROSS FIXED ASSET VALUE

Performance Category	Measure	Description
Cost Control	OM&A/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 2.1% in 2020, 0.2% higher than 2019. The higher OM&A expenditure ratio compared to past years was mainly due to additional OPEB costs and COVID-19 expenditures. Normalizing for these two items would bring costs in line with prior year. OM&A/Gross Fixed Asset Value is presented in the table below.

Table 26 - OM&A/Gross Fixed Asset Value (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	2.2	1.8	1.8	
Actual	2.5	2.3	2.3	1.9	2.1	▼

Hydro One's average performance over the past five years (2016-20) was 2.2%. The OM&A ratio is trending downwards, due to decreased levels of operating and maintenance expenditures and increasing gross fixed assets.

TARGETS

For 2023, Hydro One is targeting a ratio of 1.9%. For OM&A measures, Hydro One is not forecasting targets beyond the 2023 test year used to establish OM&A funding because OM&A levels during the remainder of the test period will be determined through the application of the Custom IR framework. Hydro One will continue to strive to work within the OEB-approved OM&A budget.

Table 27 OM&A/Gross Fixed Asset Value (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	1.7	1.6	1.9				

2.5.2.2.4.3 LINE CLEARING COST PER KILOMETER

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 kilometre cleared annually. In recent years, Hydro One's vegetation management activities have exceeded the optimal levels of a six-year cycle in the South, Central, and East regions and an eight-year cycle in North. During the early part of the 2016-2018 period, the focus was on continuing to address the backlog of line clearing and bringing tree edges back to original design specifications. From 2018-2020, more vegetation in urban corridors was identified and treated to address vegetation that had accumulated from previous cycles in reaction to community desire to reduce tree pruning and clearance. Zero tolerance enforcement of the NERC FAC-003 Standard regarding minimum clearances for vegetation growth has led Hydro One to increase its urban vegetation management resulting in higher costs per kilometer. Line Clearing Cost per kilometer is presented in the table below.

Table 28 - Line Clearing Cost per Kilometer ($/km)

	2016	2017	2018	2019	2020	Trend
Target	-	-	2,295	2,295	2,264	
Actual	1,966	2,100	2,797	3,817	3,368	▲

Over the past five years (2016-2020), Hydro One's average line clearing cost was $2,822 per kilometer, and the average annual number of kilometers cleared was 2,564 kilometers. For 2020, Hydro One’s cost per kilometer of line cleared was $3,368, a decrease of $449 or about 12% compared to 2019, primarily due to the factors discussed below.

Hydro One’s past performance shows an increasing trend in the cost per kilometer, mainly attributable to the increase in work required to bring back corridors to design width across the province and increased work requirements to maintain urban corridors based on the transmission industry and NERC standards as discussed above and to be responsive to customers and local requirements. In 2019, Hydro One Forestry specifically went through a major technology change and associated training, enabling foresters to use tablets to notify and execute work by logging defects in the system. This one year change increased costs in 2019 relative to those observed in 2020.

TARGETS

Over the 2023-2027 period, Hydro One aims to achieve line clearing unit costs averaging $2,927, and to execute over 2,100 km annually. Based on customer feedback, Hydro One introduced flexibility into the Vegetation Management Standard for line clearing, such as increased discretion in clearing or trimming incompatible vegetation in border zones of corridors. Hydro One expects regularly scheduled cyclical maintenance to continue with some work deferrals, while remaining within the current transmission vegetation budget levels recognizing the rising unit cost trend.

Table 29 - Line Clearing Cost per Kilometer ($/km) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	2,200	2,175	2,784	2,854	2,925	2,998	3,073

2.5.2.2.4.4 BRUSH CONTROL COST PER HECTARE

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. For 2020, Hydro One’s brush control cost was $1,538 per hectare and 12,501 hectares were completed. In 2019, the cost was $1,924 per hectare and 7,779 hectares were completed. Where feasible, the brush control work cycles are aligned with line clearing to streamline work planning and execution. Brush Control Cost per Hectare is presented in the table below.

Table 30 - Brush Control Cost per Hectare ($/Ha)

	2016	2017	2018	2019	2020	Trend
Target	-	-	1,625	1,625	1,620	
Actual	1,542	1,356	1,539	1,924	1,538	▲

Hydro One's average brush control cost over the past five years (2016-2020) was $1,580 per hectare, and the average annual number of hectares completed over the same period was 11,463 hectares. Hydro One’s performance trend indicates a very minor increase in the cost per hectare over this period, mainly attributable to improved control of corridors due to the past cycle’s thorough brush control maintenance work using mechanical clearing.

TARGETS

Hydro One continues to invest in vegetation management on all of the transmission corridors to address the vegetation that is most likely to impact system reliability. Over the 2023-2027 period, Hydro One is targeting average brush control unit costs of $1,712 and planning to execute an average of 11,500 hectares annually. Flexibility in Hydro One's Vegetation Management Standard for brush control has been introduced, such as the removal of tower base clearing as part of the scope, to reduce unit costs. This will support continued cyclical maintenance, minimize deferrals, and reduce accumulation of backlog within the current transmission vegetation budget levels.

Table 31 - Brush Control Cost per Hectare ($/Ha) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	1,630	1,608	1,628	1,669	1,711	1,754	1,798

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. With strategic alignment of work and resource deployment, increasing flexibility in Hydro One's Vegetation Management Standard, and technological improvements, this work program is expected to be executed over the 2023-2027 period within the forecasted costs.

2.5.2.3 PUBLIC POLICY RESPONSIVENESS

The measures in this category demonstrate Hydro One's commitment to deliver on obligations mandated by the government and regulatory agencies.

2.5.2.3.1 RENEWABLE ENERGY

2.5.2.3.1.1 ON-TIME COMPLETION OF RENEWABLES CUSTOMER IMPACT ASSESSMENTS

Performance Category	Measure	Description
Renewable Energy	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 in 150 days.

For transmission-connected generators, Hydro One completes customer impact assessments and measures its performance as the successful completion of these assessments against a standard of 150 days.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In 2020, for the seventh consecutive year, Hydro One completed 100% of the customer impact assessments within the allotted time. Hydro One attributes its consistent performance mainly to its well defined internal processes and closely coordinating and managing these activities with the Independent Electricity System Operator (IESO).

Table 32 - On-time Completion of Renewables Customer Impact Assessments (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	100	100	100	
Actual	100	100	100	100	100	►

TARGETS

The number of assessments performed has fallen significantly and Hydro One does not anticipate a substantial number of assessments being requested over the 2023-2027 period. Nevertheless, Hydro One is targeting 100% completion within the allotted time for the customer impact assessments requests received.

Table 33 - On-time Completion of Renewables Customer Impact Assessments (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.3.2 REGIONAL INFRASTRUCTURE PLANNING AND LONG-TERM ENERGY PLAN RIGHT SIZING

2.5.2.3.2.1 REGIONAL INFRASTRUCTURE PLANNING PROCESS: % OF DELIVERABLE 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 plans, reports and LDC status update letters.

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 regional planning cycle, more than 70 planning reports and 30 planning status letters were completed. The second cycle of regional planning is currently underway and Hydro One has completed more than 40 planning reports. These reports are published on the Hydro One website. Hydro One files an Annual Status Report with the OEB on November 1 of each year detailing its performance.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

In 2020, for the seventh consecutive year, 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 IESO.

Table 34 - Regional Infrastructure Planning Progress (%)

	2016	2017	2018	2019	2020	Trend
Target	-	-	100	100	100	
Actual	100	100	100	100	100	►

TARGETS

Over the 2023-2027 period, Hydro One plans to maintain its performance at 100%.

Table 35 - Regional Infrastructure Planning Progress (%) Targets

	2021	2022	2023	2024	2025	2026	2027
Target	100	100	100	100	100	100	100

2.5.2.3.2.2 LONG-TERM ENERGY PLAN (LTEP) END-OF-LIFE RIGHT-SIZING ASSESSMENT EXPECTATIONS

Performance Category	Measure	Description
Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing	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 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. Hydro One made changes to the Regional Planning process to ensure that major transmission assets that are nearing end-of-life are adequately assessed by the regional planning Study Team 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. Hydro One has been engaged with the IESO and the OEB in response to this recommendation in the LTEP. While the LTEP is under review, adherence to the principles continues as this measure tracks Hydro One's public policy responsiveness. In 2020, Hydro One met 100% of its End-of-Life Right Sizing Assessment Expectations.

Table 36 - End-of-Life Right-Sizing Assessment Expectation

	2016	2017	2018	2019	2020	Trend
Target	-	-	Met	Met	Met	
Actual	-	Met	Met	Met	Met	

TARGETS

Over the plan period, Hydro One is targeting to continue a “Met” score in all years.

Table 37 - End-of-Life Right-Sizing Assessment Expectation Targets

	2021	2022	2023	2024	2025	2026	2027
Target	Met	Met	Met	Met	Met	Met	Met

2.5.2.4 FINANCIAL PERFORMANCE

2.5.2.4.1 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.

2.5.2.4.1.1 LIQUIDITY: CURRENT RATIO

Performance Category	Measures	Description
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Liquidity is measures as the ratio of the current assets to current liabilities. Current assets is defined as cash or other assets to be converted to cash within the year. Current liabilities is defined as short term debts or financial obligations that become due within the year.

HISTORICAL PERFORMANCE AND VARIANCE TO TARGETS

Hydro One reported a current ratio for the transmission segment was 0.28 in 2020; representing a 40% increase from 2019 and a 133% increase compared to 2018. The 2020 result indicates that for every one dollar of current liabilities, Hydro One had $0.28 in current assets.

Table 38 - Liquidity: Current Ratio

	2016	2017	2018	2019	2020
Actual	0.20	0.13	0.12	0.20	0.28

Hydro One's average current ratio over the past five years (2016-20) was 0.19, and is trending upwards due to higher current assets and/or lower current liabilities. Due to the nature of this measure, Hydro One has not provided a forecast outlining future financial performance expectations.

2.5.2.4.1.2 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 1.50 in 2020, representing a decrease of about 1% compared to 2019. 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. The OEB-deemed capital structure is 60% debt to 40% equity (a ratio of 1.50).

Table 39 - Leverage: Total Debt to Equity Ratio

	2016	2017	2018	2019	2020
Actual	1.43	1.47	1.53	1.52	1.50

Hydro One's average debt to equity ratio over the past five years (2016-20) was 1.49, and has a relatively stable trend, which matches the OEB-deemed ratio of 1.50. The average debt to equity ratio was previously less than the deemed structure of 1.50 largely due to a low dividend payout for the business, as directed by its prior sole shareholder, the Province of Ontario. After Hydro One’s Initial Public Offering in 2015, its debt to equity ratio was adjusted to conform more closely to the OEB-deemed capital structure, and management has indicated that it intends to maintain this ratio at or around that level.

2.5.2.4.1.3 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 2020 achieved regulatory return on equity (ROE) was 9.29% for its transmission segment, against an OEB-deemed ROE of 8.52%. The 2020 achieved ROE was higher than deemed due to higher actual loads than anticipated which resulted in increased revenues, higher external and internal revenues, offset by CDM variance account revenues recognized in 2020 but relates to 2017; and lower removal costs.

Table 40 - Regulatory Return on Equity -Deemed Return on Equity (%)

	2016	2017	2018	2019	2020
Deemed	9.19	8.78	9.00	N/A	8.52
Actual	10.02	9.03	11.08	9.53	9.29

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.

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Appendix 5-A
Metrics

Metric Category	Metric	Measures	
		1 Year	5 Year Average
Cost	Total Cost per Delivery Point[1]	2,282,537.65	2,054,671.13
	Total Cost per km of Line[2]	56,175.54	49,935.93
	Total Cost per MW[3]	63,118.52	61,152.25
CAPEX	Total CAPEX per Delivery Point	1,693,029.86	1,453,669.06
	Total CAPEX per km of Line	41,667.16	35,331.99
O&M	Total O&M per Delivery Point	589,507.79	601,002.07
	Total O&M per km of Line	14,508.38	14,603.94

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations (complete only if applicable)
Metric Name:
Total Cost per Delivery Point: Hydro One Transmission is using the number of Delivery Points as an alternative for the number of customers.
Metric Name:
Total CAPEX per Delivery Point: Hydro One Transmission is using the number of Delivery Points as an alternative for the number of customers.
Metric Name:
Total O&M per Delivery Point: Hydro One Transmission is using the number of Delivery Points as an alternative for the number of customers.

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Including outages caused by loss of supply*					Excluding outages caused by loss of supply*					Excluding extraordinary events**				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
T-SAIDI											80.8	42.8	70.0	38.9	61.3
T-SAIFI											0.79	1.13	1.33	1.02	0.90

5 Year Historical Average

	Including outages caused by loss of supply*	Excluding outages caused by loss of supply*	Excluding extraordinary events**
T-SAIDI			58.7
T-SAIFI			1.03

T-SAIDI = Transmission System Average Interruption Duration Index

T-SAIFI = Transmission System Average Interruption Frequency Index

* Not applicable to Transmission

** Exludes Major Events in 2019 and onward - refer to TSP Section 2.5

Service Quality***

Indicator	OEB Minimum Standard	2016	2017	2018	2019	2020
Low Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	n/a	n/a	n/a	n/a	n/a
Appointments Met	90.0%	n/a	n/a	n/a	n/a	n/a
Written Response to Enquires	80.0%	n/a	n/a	n/a	n/a	n/a
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	n/a
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	90.0%	n/a	n/a	n/a	n/a	n/a
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	n/a	n/a	n/a	n/a	n/a

*** Not applicable to Transmission

SECTION 2.6 - TSP - OTHER CAPITAL PLANNING FACTORS AND CONSIDERATIONS

2.6.1 INTRODUCTION

TSP Sections 2.2 through 2.4 presented planning considerations from the lens of transmission system and asset needs, benchmarking results and reliability. This section focuses on other planning factors and considerations that shaped, informed, and impacted the development of the TSP, in accordance with the principles and requirements of the OEB's Renewed Regulatory Framework (RRF), such as:

- Customer needs and preferences as identified through customer engagement;
- Statutory and regulatory requirements, including investments directed to be undertaken or requested by third parties, e.g. IESO, Long-Term Energy Plan (LTEP) and customers.

This section also summarizes the steps that Hydro One has taken to address the OEB's direction from Hydro One Transmission's last rate application (EB-2019-0082) in respect of Transmission Line Losses (section 2.6.4).

2.6.2 HOW THE CAPITAL PLAN REFLECTS CUSTOMER ENGAGEMENT

As discussed in SPF Sections 1.6, Hydro One undertakes a broad range of customer engagement activities, including a formal customer engagement survey that specifically informs the development of the TSP. On this basis, Hydro One is able to understand the outcomes that its customers care about, as well as the level and mix of investments that they would like to see included in the investment plan. The feedback obtained through these engagement activities provides an important and direct input into Hydro One's investment planning process, resulting in an investment plan that is closely aligned with and highly responsive to customer needs and preferences.

In 2019, prior to beginning the investment planning process for this TSP, Hydro One undertook a two-phase transmission customer engagement survey to identify the needs and preferences of transmission customers, as further described in SPF Section 1.6. The survey was completed sufficiently in advance, allowing Hydro One to hold a series of cross functional sessions to review relevant findings, trends and specific customer feedback as well as to incorporate customer priorities into the TSP.

Throughout the planning process, Hydro One ensured the alignment of investment drivers with identified customer needs and preferences. From the candidate investment development stage through to TSP finalization, the funding status of customer flagged investments was actively monitored, discussed and considered. These considerations were also integral to the review and approval of the business plan by Hydro One's Executive Leadership Team and its Board of Directors. The final investment plan reflects the results of customer engagement while balancing system and asset needs, and transmission rates.

For further details on how the TSP reflects the pacing of investments supported by customers as well as the type of investments identified through ongoing customer coordination and collaboration, refer to TSP Section 2.8.

2.6.3 HOW THE CAPITAL PLAN REFLECTS STATUTORY AND REGULATORY OBLIGATIONS

This section summarizes the following planning factors and considerations that have influenced the development of the TSP:

- Regional Planning needs;
- Investments directed by third parties, e.g. government, IESO, LTEP and customers; and
- Other regulatory requirements and considerations, including industry and reliability standards.

2.6.3.1 HOW THE CAPITAL PLAN REFLECTS REGIONAL PLANNING NEEDS

As further discussed in SPF Section 1.2, regional planning addresses 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 115kV and 230kV portions of the power system, that 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 the specific region.

The investments identified through the Regional Planning process that form part of the TSP account for approximately $2.1B of gross capital expenditures over the 2023-2027 period. Some of these investment costs are recoverable from customers in accordance with the Transmission System Code and, as such, the net capital impact of investments resulting from regional process account for about $2.0B of the total net capital expenditures proposed in the TSP. 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 2.11.

2.6.3.2 HOW THE CAPITAL PLAN INCORPORATES PROJECTS DIRECTED OR REQUESTED BY THIRD PARTIES

Pursuant to its statutory and regulatory obligations under the Electricity Transmission Licence, Transmission System Code, *Public Service Works on Highways Act*, among others, Hydro One is required to connect customers' facilities to its transmission system upon request from a customer; relocate its assets upon request from municipal and provincial governments and agencies to support transit expansion; undertake investments necessary to expand/reinforce the Ontario transmission system consistent with IESO directions. As a result, the TSP includes a number of investments required to satisfy Hydro One's statutory and regulatory obligations. These investments include the following:

- Load or generator customer connections;
- Transmission facilities relocations;
- System expansion/reinforcement.

Further details relating to the above mentioned investments can be found in TSP Section 2.8 and the associated System Access, System Service and System Renewal investment summary documents.

2.6.3.3 HOW THE PLAN INCORPORATES 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 among others, safety standards, reliability standards, environmental and noise mitigation standards, and cyber security standards. The need to meet these standards is a mandatory requirement and key to ensuring that Hydro One's transmission system continues to operate in a safe and reliable manner. Standards that are applicable to planning, design, operation, and maintenance of Hydro One's transmission system are constantly changing and become more onerous to adhere. As a result, Hydro One's proposed investment plan includes a variety of investments required to ensure Hydro One's continued adherence and 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 2.11.

2.6.4 HOW HYDRO ONE HAS ADDRESSED THE OEB'S FINDINGS IN RESPECT OF TRANSMISSION LINE LOSSES

This Section discusses transmission line losses and Hydro One's response to the OEB's findings in respect of transmission line losses in the EB-2019-0082 Decision and Order.

2.6.4.1 LINE LOSSES ON THE TRANSMISSION SYSTEM

Line losses occur in the transmission system as power flows through a transmission line from a generation source to a load. The amount of losses is dependent on the resistance of the transmission line (i.e., the type and length of conductor), resistance of other transmission equipment (i.e., transformers), and the amount of power flowing in the line and other equipment.

The responsibility for managing transmission line losses is split between Hydro One and the Independent Electricity System Operator (IESO). Hydro One's ability to manage transmission line losses is limited to its role as an owner of transmission assets in the planning, selection, maintenance and operation of its transmission equipment, subject to the inherent physical limitations of that equipment. Losses attributable to the physical characteristics of the transmission system are fixed once the system is built and can only be changed through subsequent investment in the transmission system. Across the industry, line loss mitigation generally occurs as part of investments undertaken to address asset condition and/or capacity needs and not purely to reduce losses. Nevertheless, Hydro One is committed to finding opportunities to reduce transmission line losses where practical and economical.

2.6.4.2 EB-2019-0082 DECISION

In Hydro One's previous transmission rate application (EB-2019-0082), the OEB accepted the settlement between Hydro One and Environmental Defence on Issue 8: Transmission Line Loss Reduction Opportunities.[1] Hydro One has addressed all of the settlement terms (presented in *italics*), as discussed below.

2.6.4.2.1 TERM 1: IESO STAKEHOLDER ENGAGEMENT

Hydro One will participate in, and contribute to, the ongoing IESO stakeholder engagement on transmission line losses, including offering to be a contributor to the final report which will document the IESO and Hydro One's respective practices with regard to mitigating transmission line losses as well as identifying potential areas for overall net benefit reductions in transmission line losses.

[1] EB-2019-0082, Decision and Order, April 23, 2020, pp. 58-59.

Hydro One continues to participate in, and contribute to, the IESO stakeholder engagement process on transmission line losses. Hydro One participated in the IESO's Public Information Session on September 6, 2019, collaborated with the IESO in preparing and presenting parts of the IESO Engagement Webinar on September 30, 2020, and helped to provide responses to stakeholder feedback received on October 22, 2020. Hydro One continues to work with the IESO as the IESO prepares for its next engagement webinar in 2021.

2.6.4.2.2 TERM 2: IDENTIFY ADDITIONAL OPPORTUNITIES

As part of the IESO stakeholder engagement process, Hydro One will endeavor to identify any additional opportunities to cost-effectively reduce transmission losses including through improved processes, option analysis methodologies, documentation and reporting. This includes the opportunities for improvement identified in points 3 and 4 below.

Hydro One is committed to finding opportunities to reduce transmission line losses where practical and economical. To date, the IESO stakeholder engagement process has not identified additional opportunities to cost-effectively reduce transmission line losses other than those presented in existing industry transmission line loss reports (which Hydro One's processes are generally aligned with, as further discussed below).[2] However, during the IESO stakeholder engagement process, the relevant inputs to be considered to evaluate project options have been raised. In addition, Stantec through its independent review of Hydro One's line loss process made recommendations that Hydro One has begun implementing (as discussed below).

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[2] TSP 2.3 Attachment 4 (Stantec Review): "Hydro One's practices related to transmission line losses are generally aligned with the recommendations outlined in the National Grid Strategy Paper, CEER 2017 Report, and CEER 2020 Report"; EB-2019-0082, TSP Section 1.8, Attachment 1 (EPRI Report): "Hydro One design practices are materially consistent with industry best practices for loss mitigation".

2.6.4.2.3 TERM 3: PREPARE LINE LOSS GUIDELINE

Hydro One will prepare an internal Hydro One guideline delineating the transmission line loss process that Hydro One will follow and is accountable for. This will be developed in Q1 2020 and refined throughout the IESO stakeholder consultation as necessary.

Hydro One began preparing and refining its Transmission Line Loss Guideline throughout 2020 as the IESO Transmission Losses Engagement continued, finalized the draft guideline at the end of 2020, and completed the guideline on March 1, 2021. The guideline documents Hydro One's transmission line loss process for assessing transmission capital investment alternatives and includes an options analysis workbook to ensure consistent application of the process. The options analysis methodology considers the impact of line losses on the ranking of alternatives, taking into account each option's annual revenue cost and the associated cost of annual loss to identify the lowest cost alternative.

On May 12, 2021 Hydro One hosted a Transmission Line Loss Stakeholder Consultation where the Transmission Line Loss Guideline was discussed with intervenors from Hydro One's previous transmission rate application (as discussed below). The stakeholder consultation allowed Hydro One to understand and consider participants' perspectives regarding its guideline and determine where updates may be considered when Hydro One reviews the guideline in 2022.

2.6.4.2.4 TERM 4: REFLECTING LOSSES IN BUSINESS CASES

In business cases for projects where transmission line losses are material, Hydro One will include an option analysis and report on transmission line losses. This will be implemented over the course of 2020 for any projects meeting a documented materiality threshold.

Hydro One's Transmission Line Loss Guideline provides direction to its transmission planners to assess the impact of line losses on the ranking of investment alternatives and document the line loss reduction for the preferred investment option where a Business Case Summary (BCS) is prepared.

2.6.4.2.5 TERM 5: INDEPENDENT THIRD PARTY REVIEW OF HYDRO ONE'S PROCESSES

At the end of the IESO stakeholder consultation and issuance of the IESO report, if the IESO determines that it will not proceed to engage an independent third party to review the IESO's and Hydro One's processes, Hydro One will initiate an independent third party review of its own processes for cost-effectively reducing transmission line losses, to be filed at its next rate application. This review would aim to identify any additional opportunities to cost-effectively reduce transmission line losses, including through improved processes, option analysis methodologies, documentation, and reporting, and would invite input from stakeholders.

In 2020, Hydro One determined that in order to meet its filing schedule for this transmission application, it would need to begin the independent third party review of its line loss processes in parallel with the IESO stakeholder engagement on transmission line losses. The IESO engagement is ongoing with the next engagement webinar expected in late 2021. Further information may be found on the IESO engagement website.[3]

Hydro One engaged Stantec to complete the independent third party review of its transmission line loss processes with a view to assess the principles and completeness of such processes and identify potential opportunities to cost-effectively reduce transmission line losses. Stantec was selected because of its transmission system expertise and experience in the area of transmission line losses.

In conducting its assessment, Stantec completed a comprehensive review of a number of industry transmission line loss reports and Hydro One's Transmission Line Loss Guideline, considered the IESO stakeholder engagement materials, and relied on its extensive professional experiences and knowledge of line loss practices in other jurisdictions.

[3] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Losses

On May 12, 2021 Hydro One hosted a Transmission Line Loss Stakeholder Consultation. Hydro One invited all intervenors from its previous transmission rate application to attend the consultation. Hydro One, Stantec and representatives from 15 intervenor groups attended the consultation to discuss Stantec's preliminary findings and recommendations, and to discuss Hydro One's Transmission Line Loss Guideline. The consultation provided a forum for dialogue between Hydro One and participants, allowed participants to provide their comments on Hydro One's guideline and the preliminary results of the third party review, and allowed Stantec and Hydro One to understand and consider the perspectives of the participants.

Stantec concluded that the Transmission Line Loss Guideline provides a reasonable approach in determining the cost impact of line loss and supports planning decisions for customer connections, system reinforcement, system facility refurbishment and local area supply investments. Furthermore, Stantec concluded that Hydro One's practices related to transmission line losses are generally aligned with the recommendations outlined in the industry papers (as they relate to transmitters) reviewed by Stantec, and concurs with the findings in EPRI's March 2018 report that Hydro One's design practices are generally consistent with industry best practices for line loss mitigation. Stantec's report recommended i) Hydro One ensure implementation and consistent use of the Transmission Line Loss Guideline and ii) Hydro One track the number of projects that have been assessed for transmission line loss mitigation and the associated MW reduction in losses as documented in approved business cases. Hydro One has begun implementing these recommendations. Further information on Stantec's independent third party review may be found in TSP 2.3 Attachment 4.

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SECTION 2.7 – TSP - INVESTMENT PLANNING PROCESS

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 asset management and investment planning processes that represent 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 System Plans) that prudently addresses system and asset needs in alignment with Hydro One's strategic priorities and the customer service imperatives that are at the core of its business mandate. This planning framework accounts for and strives to achieve outcomes that are consistent with the OEB's RRF and that reflects the priorities valued by customers (as informed by customer engagement), as described in detail in SPF Sections 1.6 and 1.7.

This section highlights and supplements the evidence in SPF Section 1.7, further discussing the considerations that apply in the context of managing and investing in Hydro One's transmission assets.

- Section 2.7.1 provides an overview of the components that make up the system planning process.
- Section 2.7.2 discusses the strategy and context that guide planning (as detailed in SPF Section 1.7.2).
- Section 2.7.3 discusses elements of the asset management process (as detailed in SPF, Section 1.7.3) as applied to transmission assets.
- Section 2.7.4 discusses the investment planning process (as detailed in SPF, Section 1.7.4) that underpinned this TSP.

2.7.1 SYSTEM PLANNING PROCESS PHASES

Hydro One’s system planning process is a robust and value-driven approach to assess system and asset-related risks and to address those risks through investments that align with the company’s strategic priorities and objectives as well as customer needs and preferences. This 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. Based on this process, Hydro One is able to establish investment solutions that will cost-effectively mitigate risks over the planning period.

The system planning process includes the following three phases, which are discussed in detail in SPF Section 1.7 and illustrated in Figure 1 below:

1. **Strategy and Context** – Hydro One identifies long-term system needs within the context of asset condition, customer priorities, and system needs. This phase includes the first phase of the customer engagement process described in SPF Section 1.6.
2. **Asset Management** – Asset management is a lifecycle approach that balances asset needs performance, costs and associated risks during the asset' service life. This process includes the monitoring and assessment of the current state of the transmission system as well as the development of potential candidate investments.
3. **Investment Planning** – Through the investment planning process, Hydro One evaluates and prioritizes candidate investments to arrive at the final TSP. As a part of this process, feedback obtained from the second phase of customer engagement is considered and reflected in trade-off decisions as appropriate.

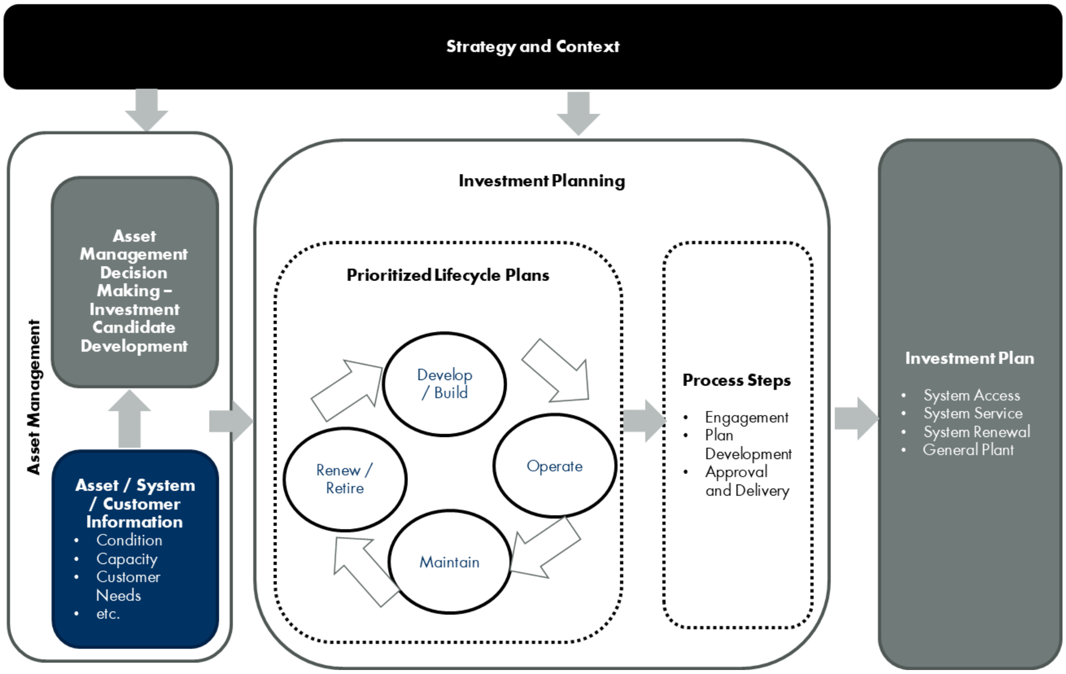

Figure 1: System Planning Process Diagram

2.7.2 STRATEGY AND CONTEXT

The TSP is informed by Hydro One's strategic priorities, as presented in Figure 2 below.

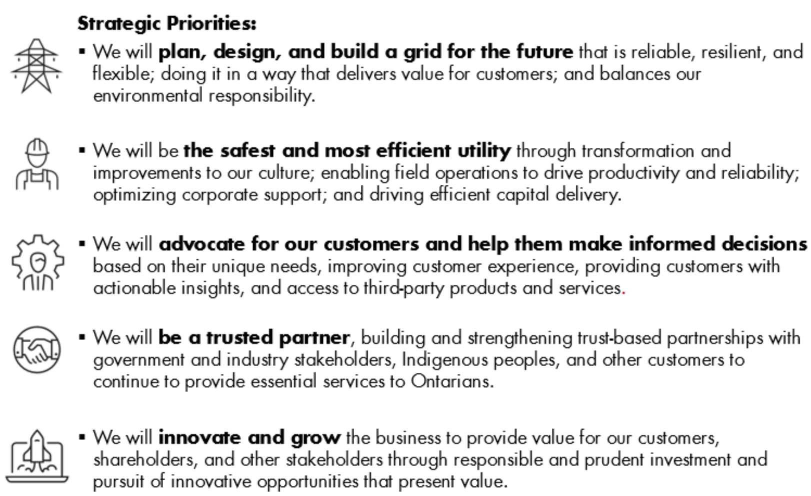

Figure 2: Hydro One's Strategic Priorities

Moreover, in managing assets that are critical to customers and Ontario's economy, Hydro One is committed to meet the RRF outcomes and has integrated them into its investment planning process. The result is that the outcomes of the TSP align with the principles of the RRF with the aim to achieve the following 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.

As demonstrated in the Transmission Investment Summary Documents (see TSP Section 2.11), each investment reflects explicit consideration for the achievement of RRF aligned outcomes.

Hydro One's planning context is in large part influenced by customer needs, preferences and priorities. To engage with customers consistently and proactively, Hydro One undertakes a spectrum of customer engagement activities. As described in SPF Section 1.6, these activities increase the company's understanding of customer needs and preferences so as to more effectively target outcomes that are valued by customers and plan or deliver work programs to achieve those outcomes. Customer engagement is detailed in SPF Sections 1.6 and 1.7, and also highlighted as part of Section 0 below.

2.7.3 ASSET MANAGEMENT PROCESS

Hydro One employs a lifecycle management approach which considers and balances asset performance, costs and associated risks during the asset's service life. By monitoring the current state of its transmission assets and identifying current and future needs, Hydro One develops a set of candidate investments, which are then evaluated and prioritized via the investment planning process (discussed in Section 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, including the evaluation of actual and anticipated asset, customer, and overall system needs, along with other external factors that influence investments. These assessments are described below.

ASSET NEEDS ASSESSMENT

Hydro One continuously assesses the transmission system to determine asset needs. With asset condition being the primary consideration in this assessment, Hydro One also considers other factors such as asset criticality, utilization and performance. While the age demographics of specific asset groups provide insight into long-term needs at the fleet level, age is not the primary driver for any specific investments. Information on the assessment of major transmission asset types is provided in TSP Section 2.2 – Asset Information and Lifecycle Strategies.

Notably, System Renewal investments are largely underpinned by asset condition data from ongoing asset needs assessment, including (i) Transmission Air Blast Circuit Breaker Replacements to address poor performing air blast circuit breakers (TSP Section 2.11, T-SR-02), and (ii) Transmission Line Refurbishments to address poor condition overhead conductors and related infrastructure.

CUSTOMER NEEDS

Hydro One engages with customers proactively and regularly through various mechanisms, including customer connection requests, ongoing engagement activities, and formal customer surveys. Understanding the needs of customers is critical to Hydro One's business, especially given its diverse customer base (consisting of generators, large industrial end-users, and

Ontario's LDCs) that is supplied by the transmission system across different regions of the province.

Feedback from customer engagement informed the development of the investment plan. In 2019 and 2020, a comprehensive, two-phase customer engagement exercise was conducted in conjunction with the planning process. Feedback from phase 1 provided valuable input (including indicative investment envelopes and preferred outcomes) for the development of initial scenarios. Overall, transmission customers prioritized reasonable rates and reliable service. In respect of reliability outcomes, they generally valued reduced restoration duration and fewer outages due to extreme weather. With respect to trade-offs, a majority wanted to see the current level of investment for replacing aging transmission infrastructure be maintained or increased, investment in a more reliable transmission system (either as part of ongoing renewal or proactive investments), and investment in power quality improvement.

Customer priorities informed the derivation of investment strategies and candidate investments, including the appropriate pacing for the planning period. These initial themes and priorities provided a key input for the development of phase 2 investment scenarios (with corresponding service outcomes and rate impact), allowing customers to provide feedback on trade-off options and enabling Hydro One to consider and reflect this feedback as appropriate through its investment decisions.

In addition to customer preference regarding priorities and trade-offs, specific customer needs in terms of connection to the system have directly driven the establishment of various System Access investments in this TSP, including (i) New Customer Connection Stations (TSP Section 2.11, T-SA-01) and (ii) Connection of Metrolinx Traction Substations (TSP Section 2.11, T-SA-04). The incorporation of customer feedback into the final investment plan is further discussed in Section 2.7.4 below.

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 aims to ensure adequate capacity to supply customers and areas connected to its transmission system, mitigate against potential high-impact events to ensure safe and reliable operations in accordance with mandatory requirements, and provide for transmission facility needs identified from regional planning (as discussed in SPF Section 1.2). With respect to regional planning, Hydro One Transmission is the lead transmitter responsible for the development of needs assessment and regional infrastructure plans in 20 of the 21 planning regions, in conjunction with customers, the IESO and LDCs.

Notably, System Service investments arising from system needs assessments include: (i) Merivale x Hawthorne Upgrades to increase capacity to meet future demand requirements (TSP Section 2.11, T-SS-03), and (ii) West of London Transmission Reinforcement to relieve capacity constraints in Southwest Ontario (TSP Section 2.11, T-SS-09).

EXTERNAL AND OTHER INFLUENCES

Hydro One leverages information regarding industry best practices, trends and benchmarking to evaluate its performance against peer utilities. These studies and comparisons generate insight regarding Hydro One's operations relative to benchmark comparators, which can guide continuous improvement efforts and inform investment decision-making. A discussion of the studies related to this 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 their total risk mitigation, risk spend efficiency and contribution to desired outcomes, and are calibrated to consistently assess relevant risks across the organization, as summarized below and detailed in SPF Section 1.7.

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 taxonomies as applicable – safety, reliability, and environmental. Each risk taxonomy features clear definitions and a consistent approach to permit a proper assessment of the risk mitigated for each candidate investment. The assessment considers both the probability and consequence of an event materializing, relying on historical data, condition information and experience to the extent possible and taking into account the risk mitigated by each candidate investment through the comparison of the risk profile pre and post investment.

Hydro One also utilizes a "flagging" process to supplement the three risk taxonomies. Flags are used to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. For example, these flags enable the consideration of compliance driven investments, as well as investments that address specific customer priorities.

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, known as "calibration sessions". These sessions bring together stakeholders from across the organization to compare approaches and assumptions in scoring investments, so as to ensure that the risk assessment and scoring process has been applied consistently.

2.7.4.3 PRIORITIZATION AND OPTIMIZATION

Results of the risk assessments are translated into risk scores, based on total risk mitigation, which are used to generate an initial prioritization of investments. Risk scores are normalized by estimated investment cost and used to rank investments by risk mitigated per dollar, or "Risk Spend Efficiency" (RSE). The absolute value of 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.

As part of these trade-off decisions, investments are promoted or demoted based on the following levers:

- Risk: augmenting the RSE prioritization by considering the risk level remaining, any unfunded investments that mitigate significant risk, as well as total/absolute risk exposure to verify that all critical risks are being addressed.
- Flags: considering investments that need to be funded due to non-risk merits.
- The consideration of both risk efficiency and risk mitigated per dollar to support prudent and data-driven trade-off decisions.

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 slower pace plan (Scenario 1) and an accelerated pace plan (Scenario 3) – which took into account customer needs and preferences from phase 1 of customer engagement and were presented for customer feedback during phase 2.

ENTERPRISE ENGAGEMENT

Enterprise engagement ensures that the investment plan is properly reviewed and updated by the executing lines of business. This process incorporates operational and execution considerations, including resourcing, material availability, and updated cost estimates, schedules, and scope. This feedback was incorporated into the three investment plan scenarios noted above.

PHASE 2 CUSTOMER ENGAGEMENT

In Phase 2 customer engagement, the three investment scenarios were presented to customers, representing trade-off choices Hydro One has within its investment plan. Scenario 1 (slower pace) prioritizes lower rate impacts by deferring the replacement of assets in poor condition to a future rate period. Scenario 2 (draft plan) sought to keep pace with and/or improve asset condition while managing costs and rate increases now and in the future. Scenario 3 (accelerated pace) involves the replacement of deteriorating assets at a faster pace, thus reducing long term risk and mitigating long term rate impacts but at a higher plan cost. Table 1 below summarizes the transmission-related investment scenarios presented to customers.

Table 1 - Transmission Investment Scenarios Presented to Customers During Phase 2

Segment	Option	Scenario 1 (Slower Pace)	Scenario 2 (Draft Plan)	Scenario 3 (Accelerated Pace)
Transmission	1. Replacing poor condition transmission lines	Slightly lower than the current level of safety and reliability performance of transmission lines	Maintain the current level of safety and overall health of transmission lines	Moderately improve the current level of safety and overall health of transmission lines
	2. Replacing poor condition transmission stations	Replacing only the most critical infrastructure, which will increases performance and environmental risks and creates need for higher investment levels later on	Maintain the overall health of transmission station infrastructure and sustain current performance and environmental risk	Improve the overall health of transmission station infrastructure and reduce the risk of equipment failure

Phase 2 provided customers with an opportunity to confirm the outcomes that they value, as well as the level of spending and mix of investments that they would like to see included in the investment plan. In general, a plurality of customers preferred the draft transmission investment plan (Scenario 2) over accelerated or slower paced options. This input ultimately informed the investment plan, as summarized in Table 2 below:

Table 2 - Reflection of Phase 2 Customer Feedback in the TSP

	Customer Inputs	How it appears in our investment plans
System Access	Requirements for timely access and grid service	Provide customers timely access to the network through customer connections and paced regional expansions
System Renewal	**Transmission** Lines: Across all customer types, the draft plan is the preferred option. Residential and small business customers show a greater interest in the accelerated pace Stations: Across all customer types, the draft plan is the preferred option	System reinvestment to address verified, condition-based asset and system needs, including replacement of ~25 poor condition transformers/year, refurbishment of ~300 km/year of deteriorated and at-risk conductors and related components

2.7.4.5 INVESTMENT PLAN DEVELOPMENT

In developing and finalizing the proposed investments, Hydro One incorporated:

- **Feedback from Phase 2 of Customer Engagement** – incorporate customer feedback and reprioritize 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 support for the draft plan, changes were minimal over the five year term of the plan.
- **Input from third party and external studies** – incorporate select recommendations from benchmarking and other studies.
- **Updated costs, schedule and scope** – reprioritizing based on updated cost and scheduled maturity, permitting completion of more/less proposed investments that are on the margin, in consideration of execution feasibility. In this regard, certain earlier

assumptions around project maturity (which in turn impact planned pacing and costs for the 2023-2027 period) were modified to reflect updated information.

2.7.4.6 INVESTMENT PLAN APPROVAL & DELIVERY

The final investment plan was reviewed and approved by Hydro One's Board of Directors as part of the 2023-2027 Business Plan (see Exhibit A-03-01 Attachment 1). As the plan is released to work execution teams for delivery, Hydro One closely monitors the ongoing implementation of the investment plan on a monthly basis. As unforeseen asset, system and customer needs emerge, Hydro One adapts and re-evaluates its investment plan as part of a rigorous re-direction and re-prioritization process as described in SPF Section 1.7.

SECTION 2.8 - TSP - CAPITAL EXPENDITURES - OVERVIEW

2.8.1 INTRODUCTION

This section provides an overview of the five-year capital expenditures plan and its material investments proposed in the TSP. The net capital expenditures plan is provided in Figure 1 and Table 1 below.

Table 1 - Forecast Period Capital Expenditure Summary ($M)

OEB Investment Category	Forecast Period (Planned $M) [1]					% of Portfolio
	2023	2024	2025	2026	2027	
System Access	79.4	70.9	59.8	36.5	50.1	4%
System Renewal	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0	82%
System Service	90.9	101.6	85.8	93.1	90.1	6%
General Plant (Transmission)[2]	146.8	124.0	114.2	115.9	105.0	8%
Subtotal	**1,495.0**	**1,524.9**	**1,511.4**	**1,522.8**	**1,509.2**	**100%**
Productivity[3]	-61.0	-61.0	-61.0	-61.0	-61.0	-
Grand Total	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**	**-**
System OM&A[4]	**420.5**	**-**	**-**	**-**	**-**	**-**

[1] 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 2023-2027 forecast. Further information may be found below.
[2] Details on General Plant expenditures are located in Exhibit B-04-01 General Plant System Plan (GSP).
[3] Progressive productivity represents commitments made during the 2020-22 transmission rate application for 2022 that are sustained through the test period. Incremental productivity reductions for JRAP are applied to revenue requirement via productivity stretch factors, as described in SPF Section 1.4.
[4] System OM&A reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibits E-02-01. 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-02.

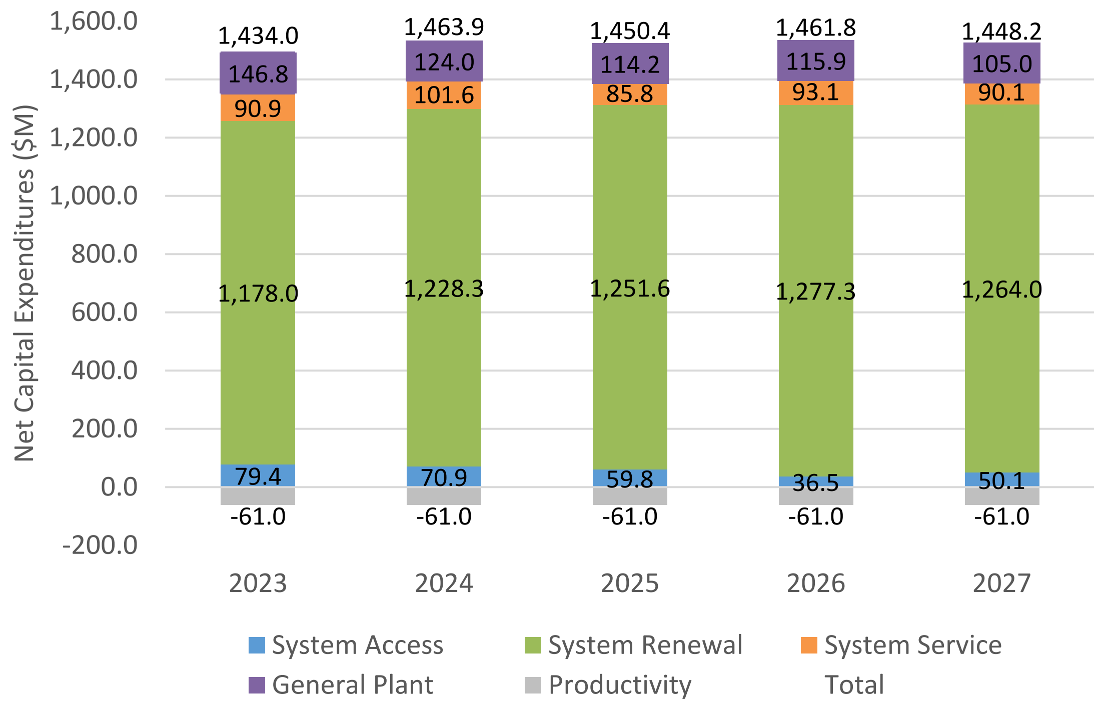

Figure 1: Forecast Period Capital Investment Summary ($M)

Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital, for a total of $7,258M, to respond to a range of asset and system needs, and to meet the customer service imperatives that are at the core of Hydro One's business mandate. System Renewal investments account for 82% of Hydro One Transmission's 2023-2027 capital plan. These investments will manage and mitigate risks stemming from assets that are in poor condition, have inadequate performance or are obsolete. The proposed System Service and System Access investments are non-discretionary and account for 10% of the total capital plan, and General Plant investments account for the remaining 8% of the capital plan. System Renewal, System Access and System Service investments are discussed in this section while General Plant investments are discussed in Exhibit B-04-01.

Exclusion of Capital Expenditures for New Partnerships

Hydro One has excluded capital expenditures over the 2023-2027 period related to investments that are expected to be fully or partially owned by and included in the rate base of new transmission-licenced partnerships, and will not form part of Hydro One's transmission rate base.

These investments may be initiated where Hydro One has, or will, receive direction from the Independent Electricity System Operator, or an Order in Council or directive from the Minister of Energy, Northern Development and Mines for the development or construction of a transmission project.

Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169). Projects, currently under development, where the transmission lines portion of capital expenditures have been excluded are the Waasigan Transmission Line, the Chatham to Lakeshore Transmission Line and the Lambton to Chatham Transmission Line. Two additional investments that are expected include a transmission line from Longwood to Chatham (IESO letter expected in 2021) and a 20 km transmission line from Lakeshore to the Leamington area (Regional Planning report expected in 2021).

2.8.2 SYSTEM OVERVIEW

Hydro One's transmission network is composed of the Bulk Electricity System (BES) and regional supply systems serving local areas. The transmission system that forms part of the BES connects major generation sources and delivers that power to load centers throughout Ontario. Electricity delivered over the transmission network is supplied by 135 generators and electricity imported into the province through interties. Hydro One's transmission system is also 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., 98% of Ontario's transmission capacity) and transported approximately 132 TWh of energy throughout the province in 2020. Hydro One's transmission customers consist of 38 local distribution companies (including Hydro One's own distribution business) and 83 large industrial customers connected directly to the transmission network, including automotive, manufacturing, chemical and natural resources businesses.

Being part of the bulk electricity system and the custodian of the system that provides 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 capacity to meet new load growth and its transmission assets perform reliably. To achieve the latter point, Hydro One has to address known risks posed by poor condition assets in a timely and cost-effective manner. Hydro One has 297 in-service transmission stations and approximately 29,000 circuit kilometers of high voltage lines. To manage a large population of transmission assets, Hydro One has robust asset management practices and investment planning process 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 preferences to provide reliable source of power.

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 RRF and addresses the four RRF outcomes as follow:

- **Customer Focus:** maintaining and where required 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 through efficient operations and responsible investment to ensure the safety and reliability of the grid.

The mix and level of capital expenditures within the proposed plan are necessary for achieving outcomes that are valued by customers and required to sustain safe and reliable transmission system operations. These outcomes include responding to deteriorating system and asset condition, funding mandatory investments to address system needs and service obligations, and investing in infrastructure that is essential to core business functions and operations.

As described in TSP Section 2.7, further to the enhancements introduced in the last transmission rate proceeding, Hydro One made additional improvements to its investment planning framework. In particular, Hydro One enhanced the alignment and integration of its investment planning process with a comprehensive, two-phase customer engagement process. This direct customer input into the priorities and pacing of the investment plan, supplement the comprehensive current state assessment, which incorporates the assessment of 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 the 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. These improvements further support the rigor and effectiveness of the planning process that underpins Hydro One’s proposed capital plan.

Hydro One's proposed investment plan is proactive and strategically paced to address the most pressing and critical needs of the system and assets. Most of Hydro One's major transmission asset categories continue to deteriorate, and, as described in TSP Section 2.2 and presented in in Figure 2 below, over 10% of all major transmission assets are in poor condition. Deteriorated asset condition correlates with the increased probability of asset failure or loss of an asset's ability to provide the intended functionality, and as such, is one of the major factors considered by Hydro One when developing its investment candidates. For each replacement decision driven by asset condition, condition is assessed before renewal work is planned or undertaken. The proposed investments do not target all poor condition assets and include assets with inadequate performance, assets that are functionally obsolete or assets that have failed. These investments address only the most pressing asset renewal needs required to ensure the levels of system performance and reliability are maintained to (i) provide the electrical energy necessary to power the provincial economy and meet the society's daily needs, (ii) meet compliance obligations, (iii) mitigate the risks to public and employee safety, and (iv) address customer needs and preferences.

In addition to risks stemming from poor condition assets, Hydro One is facing a host of other challenges, some of which include (i) government policy and regional infrastructure needs required to address system constraints, enable rapid new load growth, facilitate access and new connections to the transmission system; and (ii) changing regulatory standards and requirements relating to planning, design, operation, and (iii) maintenance of Hydro One's transmission system. The Windsor-Essex region in Southwest Ontario is currently experiencing unprecedented growth, where forecast electricity demand is expected to double over the next five years. Driven primarily by the expansion of the agricultural sector in Leamington and Kingsville, in 2019 the IESO initiated a planning study to assess the adequacy of the bulk transmission system in the region. In order to meet near-to mid-term needs, the IESO recommended and directed the construction of a new 230kV transmission station, Lakeshore TS that will be completed in 2022 along with a new 230kV double-circuit transmission line, approximately 50km from Chatham to Lakeshore targeted for completion in 2025.

Subsequently, the IESO has identified the need for further reinforcement west of London to ensure the transmission system can meet the near-to-mid-term needs in the Windsor-Essex region as published in the *West of London Bulk Study in Q2/Q3 2021*. In Q1 2021, the IESO directed Hydro One to initiate planning on a new 230kV double-circuit transmission line from Lambton to Chatham as the first phase of further reinforcement to ensure sufficient transfer capability to meet the load growth in Windsor-Essex and improve the deliverability of resources from Lambton-Sarnia throughout the province. These facilities are required no later than 2028 based on current forecasts, but the IESO has noted benefits for the bulk transmission system and region in streamlining implementation in advance of the 2028 date.

Planning, design, operation, and maintenance of Hydro One's transmission system are governed by a variety of standards, some of which are as follow:

- Forming part of interconnected North American bulk electricity system, Hydro One must adhere to numerous reliability standards and criteria defined and developed by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).
- Hydro One transmission facilities must adhere to the requirements of the *Environmental Protection Act*, R.S.O. 1990, c. E.19 (EPA). The EPA prohibits discharge of a contaminant into the natural environment and requires Hydro One to obtain a Certificate of Approval in order to construct, alter, extend or replace its station facilities.

Many transmission standards, that Hydro One must adhere to, contain stringent requirements that are constantly evolving and can materially impact replacement costs. For example, replacing a 50-year old transformer according to current standards affects the cost as follows:

- Current standards require all transformers to be upgraded to have oil spill containment systems to automatically contain and control transformer oil spills under all weather conditions, noise protection barriers and station drainage systems. As a result of these requirements, the transformer replacement costs have increased; and

- Where it is determined that changes are required to bring the old design of the low voltage (LV) switchyard up to current standards (e.g. spill containment, noise barriers, adequate fire wall separation, adequate space and clearance for workers to maintain equipment in the LV switchyard), Hydro One may have to rebuild the switchyard. As a result of these requirements, the cost to rebuild an LV switchyard has increased.

The proposed investment plan includes System Access, System Service and System Renewal investments required to ensure Hydro One remains compliant with various regulatory standards.

The sections below further detail the proposed capital expenditures, including the associated outcomes for each of the System Renewal, System Access, and System Service investment categories. Each investment category contains material investments with spending greater than $3M in any given year.

2.8.3 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. These investments account for about $593M of the gross capital expenditures for the five-year period. However, the majority of these investments are recoverable from customers in accordance with the Transmission System Code, resulting in net capital expenditures of $297M or 4% of the total net capital expenditures over the five-year plan, as shown in Table 2 below.

Table 2 - System Access Capital Expenditure Summary

OEB Investment Category	Forecast (Planned $M)						
	2023	2024	2025	2026	2027	Total of Test Years	% of Portfolio
System Access	79.4	70.9	59.8	36.5	50.1	296.7	4%

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 IESO generation contracts. Transmission asset modification investments are driven by third party requests to facilitate or permit secondary land use. The magnitude and volume of work in this investment category can vary significantly year over year based on customer requirements.

The material System Access investments within the five-year plan are shown in Table 3. A complete listing and further details regarding individual material investments are provided in TSP Section 2.11.

Table 3 - System Access Material Investments

ISD	Investment Title	2023	2024	2025	2026	2027
T-SA-01	New Customer Connection Station	13.5	13.5	-	-	-
T-SA-02	IAMGOLD – 115 kV Mine Connection	10.0	-	-	-	-
T-SA-03	Halton TS: Build a Second 230/27.6kV Station[1]	-	1.5	4.5	1.9	-
T-SA-04	Connect Metrolinx Traction Substations	3.5	3.6	0.8	-	-
T-SA-05	Future Transmission Load Connection Plans	3.1	5.2	9.4	10.4	10.4
T-SA-06	Protection and Control Modifications for Distributed Generation	-	-	-	-	-
T-SA-07	Secondary Land Use Projects	37.8	2.8	2.8	0.8	0.8
T-SA-08	H29/H30: Reconductor 230kV Circuits [1,2]	0.2	0.4	0.3	2.1	2.3
T-SA-09	New Transformer Station in Northern York Region [1]	-	-	5.6	3.7	2.4
T-SA-10	Build Leamington Area Transformer Stations [1,2]	7.6	40.9	33.5	14.5	32.6
	Other Transmission System Access	3.7	2.9	2.9	3.0	1.5
Total System Access		**79.4**	**70.9**	**59.8**	**36.5**	**50.1**

[1] *Investments identified in the Regional Planning Process*
[2] *Investments that require Leave to Construct Approval*

All of the System Access investments forecast over the planning period are based on investment needs identified through a load or generator customer and/or third party request. These investments are non-discretionary, since Hydro One is required to provide transmission access when requested pursuant to the terms of its Transmitter License and the Transmission System Code. Material System Access investments include:

- Hydro One plans to undertake $325M of gross capital work to connect load customers over the planning period. Since a significant portion of this work is recoverable from customers, the net capital impact of this work is about $189M over the planning period. The investments in load customer connection work are required to build new or expand existing transformer stations to increase capacity and meet load growth (see TSP Section 2.11, T-SA-03, T-SA-08, T-SA-09, T-SA-10), and provide connection to customers (see TSP Section 2.11, T-SA-01) including the connection to six traction power stations for the Metrolinx rail electrification project (see TSP Section 2.11, T-SA-04). The expansion of the agricultural sector and unprecedented load growth in the Windsor-Essex region of Southwest Ontario is the most significant driver of expenditure in this subcategory, representing $129M (51%) of the net capital expenditures. The load forecast in the region is anticipated to double over the next five years. In light of the forecasted load growth in the region, three new load supply stations will be constructed to connect and supply new customers in the region (see TSP Section 2.11, T-SA-10).
- Hydro One also plans to undertake $18M of gross capital work related to generation customer connections over the five-year period. All the projects in this category are below the materiality threshold and associated costs are recoverable from relevant customers. There is no net capital impact as a result of these investments over the planning period. Generator customer connection work is required to: connect generation customers at the transmission level and execute transmission system upgrades to enable such connections (see TSP Section 2.11, T-SA-06).

- Lastly, Hydro One plans to undertake approximately $61M of gross capital work related to secondary land use transmission asset modifications over the five-year 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 rights-of-ways. The size and complexity of these projects vary from year to year; the costs of majority of the projects in this category are recoverable from third parties. The net capital impact of this work is $45M over the five-year period which covers the re-establishment of property rights and corridor safety enhancements (see TSP Section 2.11, T-SA-07).

2.8.4 SYSTEM RENEWAL

System Renewal investments are made to preserve the performance of critical asset groups by evaluating assets at both an individual asset level and at a station or lines level. These investments are required to address assets that are in poor condition (as indicated by condition assessments), have inadequate performance, are functionally obsolete, or have failed, as well as to mitigate reliability and safety risk and maintain compliance with regulatory, environmental and reliability standards.

Table 2 below presents the proposed System Renewal capital expenditures over the 2023-2027 period.

Table 4 - System Renewal Capital Expenditure Summary

OEB Investment Category	Forecast (Planned $M)						
	2023	2024	2025	2026	2027	Total of Test Years	% of Portfolio
System Renewal	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0	6,199.3	82%

System Renewal investments account for 82% of the net capital expenditures over the five-year period. Some of the major System Renewal investments include:

- $1,570M over the five-year period through 35 investments that will replace network station assets that are in poor condition, have inadequate performance or are obsolete, which link major generation resources to load centers in Ontario. Hydro One's network system forms part of the BES, and as such the proposed renewal investments are required to ensure continuous power flow throughout the province and to meet all relevant IESO, NERC and NPCC requirements. Expenditures in this category address refurbishment work at major stations and replace Air Blast Circuit Breakers (ABCBs) through 11 investments. ABCBs are the poorest performing breakers in Hydro One's transmission system. These assets are installed at Ontario's most critical transmission network stations that connect nuclear and hydraulic generation stations with the total output equal to 30%[5] of Ontario's electricity generation (see TSP Section 2.11, T-SR-01 and T-SR-02).
- $1,877M over the five-year period through 102 investments that will replace connection station assets assets that are in poor condition, have inadequate performance or are obsolete, that connect network stations and transmission load delivery points. LDCs and large industrial facilities are among the customers served by connection stations. LDCs, in turn, serve Ontario's residential, commercial, institutional and small industrial end-users. Connection station assets play a critical role in supplying electricity to Ontario's homes, businesses and institutions. The proposed investments target assets that are in poor condition, have inadequate performance or are obsolete, some of which are 60-70 years old, at major connection stations such as Glendale TS, Bridgman TS, Fairbank TS that supply power to Alectra Utilities' and Toronto Hydro's distribution customers (see TSP Section 2.11, T-SR-03).

[5] (11,607MW/38,944MW)x100%; https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook Reliability Outlook Report, March 2021.

- $833M over the five-year period to replace poor condition lines asset that form part of BES or regional supply systems serving local area including 1,571 circuit-kms, or 41% of the known poor condition conductors in the fleet. These conductor sections will be addressed through 16 investments. This renewal work sustains a variety of network and radial line connected customers, including large and small municipal, First Nations communities and businesses, large load facilities such as petrochemical processing facilities, mines and paper mills (see TSP Section 2.11, T-SR-13).
- $1,086M over the five-year period to refurbish or replace various transmission line components (e.g. wood poles, insulators, shieldwires) that have been confirmed to be in poor condition. These components are integral parts of transmission line system required to enable and support the overhead conductor to perform its functions (see TSP Section 2.11, T-SR-04, T-SR-05, T-SR-06, T-SR-07, T-SR-08, T-SR-17).

The forecast of System Renewal expenditures was determined through the investment planning process (as further described in TSP Section 2.7), based on system needs and condition assessments and with regard to asset life-cycle optimization policies (as further described in TSP Section 2.2). For the five year period, individual equipment replacements have been bundled into integrated, larger scale station and line projects in order to address multiple assets and system needs at a specific station or circuit within a single investment. This integrated approach enables efficient project delivery by optimizing project planning and execution, minimizes outage requirements and customer impacts, and achieves outcomes valued by customers (as further discussed in SPF Section 1.6).

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. As can be observed in Figure 2 below, over 10% of all major transmission assets are in poor condition, with two of these asset categories (transformers and lines) experiencing increasing numbers of deteriorated assets compared to prior years with the remaining asset categories remaining relatively stable compared to prior years. A significant number of key transmission assets have been verified through condition assessments to be in poor condition. Deteriorated assets pose a material risk to Hydro One's transmission system performance, public and employee safety, and statutory and regulatory obligations that Hydro One is required to comply with.

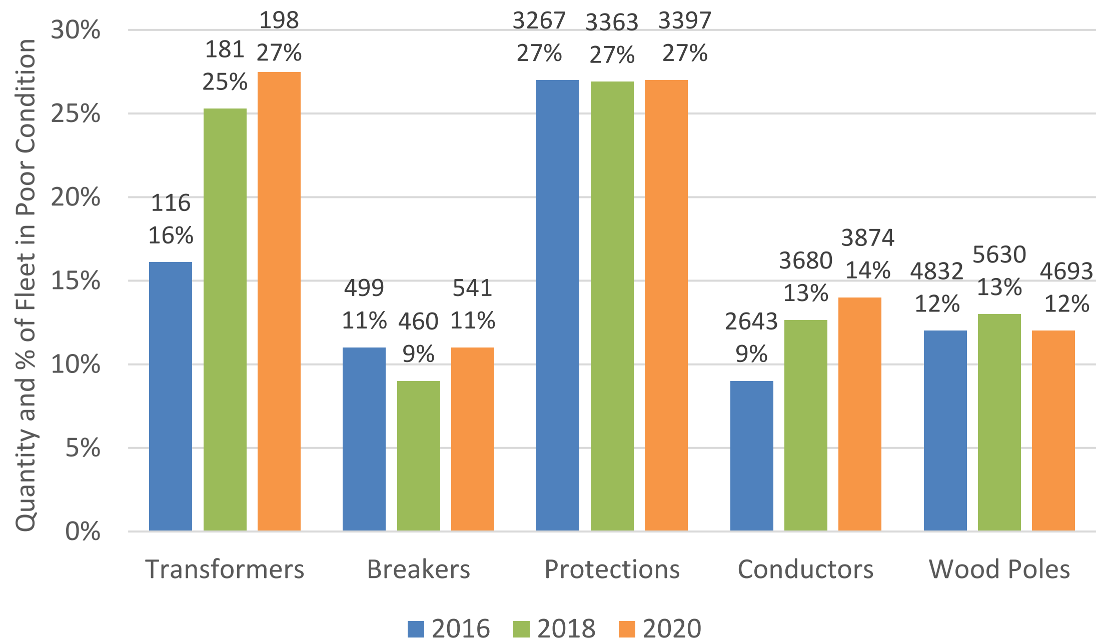

Figure 2: Transmission Assets in Poor Condition

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). 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 stations 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 that enables the failure of one of the two transformers or circuits supplying a delivery point to 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 that delivery point. This concern arises because replacing a failed asset takes a considerable amount of time. 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.

Another issue of concern when one of two transformers fail is the increased loading on the transformer remaining in operation. Hydro One’s design criteria for Dual Element Spot Network stations require that one transformer be able to temporarily carry the entire load if the companion transformer goes out of service. When one transformer is out of service, the in-service transformer can see loading up to 130-160% of its transformer rating. If both transformers are in poor condition, there is an increased likelihood that the transformer remaining in-service may also fail under these adverse overloading conditions, resulting again in a lengthy delivery point interruption.

Given the critical role of electricity in the functioning of Ontario’s homes, businesses and institutions, Hydro One does not run its transmission assets to failure. Hydro One’s priority is to maintain transmission facilities in-service. Accordingly, the proposed renewal spending focuses 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. The proposed spending is strategic and aims to ensure Hydro One replaces only those deteriorated assets that require the most attention.

Furthermore, in developing its System Renewal investments, Hydro One also identified certain critical work that has to be completed to secure nuclear sites and bulk transfers as generation resources retire or shift geographically. According to the IESO’s 2020 Annual Planning Outlook, throughout the 2020s, many existing generation contracts will expire, nuclear refurbishments will be underway, and Pickering Nuclear Generating Station will be retired. The IESO concluded that with nuclear retirements, refurbishments and contract expirations driving the need for capacity, reinforcing transmission in key areas of the province will be essential to maintaining reliability. In response to the IESO planning outlook, the System Renewal investments will improve and ensure transfer capabilities and maintain system reliability. In particular, Hydro One plans to renew its stations facilities at its Bruce A and Bruce B switching stations that connect the Bruce A and B

Nuclear Generating Stations (NGS). Hydro One has similar plans at Cherrywood Transmission Station which connects the Pickering NGS and Darlington NGS to the system. Hydro One also plans to undertake renewal work at Milton TS and Claireville TS which receive power coming from the Bruce NGS and serve as major hubs of the southern Ontario transmission system for. Further details on these investments can be found in TSP Section 2.11, T-SR-01.

While reliability statistics are an important factor, they are lagging indicators of transmission assets condition, particularly 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. Through the Customer Engagement process described in SPF Section 1.6, 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' need and preferences to ensure that transmission facilities are renewed in a timely manner and customer reliability is not jeopardized.

The material System Renewal investments for the five-year period are listed in Table 5 below. Further details on the individual investments are provided in TSP Section 2.11.

Table 5 - Major System Renewal Investments

ISD	Investment Title	2023	2024	2025	2026	2027
T-SR-01	Transmission Station Renewal - Network Stations	209.4	199.6	213.6	158.4	213.1
T-SR-02	Transmission Station Renewal - Air Blast Circuit Breakers	172.3	153.8	115.8	99.3	34.4
T-SR-03	Transmission Station Renewal - Connection Stations	334.5	357.7	350.1	406.5	428.6
T-SR-04	Wood Pole Structure Replacements	56.5	57.6	58.8	60.0	61.2
T-SR-05	Steel Structure Coating Program	23.6	24.1	24.5	25.0	25.4
T-SR-06	Tower Foundation Assess/Clean/Coat Program	17.3	17.6	17.9	18.3	18.6
T-SR-07	Transmission Line Shieldwire Replacement	12.1	12.3	12.5	12.8	13.0
T-SR-08	Transmission Line Insulator Replacement	78.4	78.1	79.5	81.0	82.5
T-SR-09	Transmission Station Demand and Spares and Targeted Assets	43.9	44.7	45.2	46.2	47.0
T-SR-10	Protection Relay Replacement Program	8.8	8.9	9.0	9.1	9.2
T-SR-11	Legacy SONET System Replacement	19.5	29.4	29.2	27.6	8.3
T-SR-12	Telecom Performance Improvements	4.2	5.8	3.8	0.0	0.0
T-SR-13	Transmission Complete Line Refurbishment	60.1	125.8	190.8	235.9	220.5
T-SR-14	Mobile Radio System Replacement	5.2	6.7	5.6	2.4	0.0
T-SR-15	Transmission Line Emergency Restoration	10.2	10.4	10.6	10.8	11.0
T-SR-16	HV UG Cable – Replace/Refurbish Pumping Plants	0.0	0.0	0.1	0.2	5.5
T-SR-17	OPGW Infrastructure Projects	28.5	27.8	30.4	20.1	10.5
T-SR-18	C5E/C7E Underground Cable Replacement	38.3	23.7	4.6	0.1	0.0
	Other Transmission System Renewal Work	55.4	44.7	49.6	63.9	75.3
Total System Renewal		**1,178.0**	**1,228.3**	**1,251.6**	**1,277.3**	**1,264.0**

System Renewal investments for stations and lines assets are separately discussed below.

2.8.4.1 STATIONS RENEWAL

The stations renewal investments are required to replace transformers, circuit breakers, protection and control, and telecom equipment that form part of bulk electricity system 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. The stations renewal investments are planned primarily based on an integrated planning and execution approach that leverages efficiencies through design, construction and commissioning. Station investments involve complete replacement of poor condition assets at a single transmission station. The scope of each investment is primarily on the key station assets, such as transformers, circuit breakers and protection systems. It may also include other station assets, such as instrument transformers, disconnect switches and other ancillary equipment, where needed.

As detailed in TSP Section 2.2, Hydro One's transmission assets are aging and Hydro One is not keeping pace with asset condition demands. Currently, there is a significant population of poor condition assets that require immediate attention. For example, relative to the prior rate application, there has been an increase in the total number of poor condition transformers from 181 units (25% of the fleet) to 198 units (27% of the fleet) and the number of poor condition breakers has increased from 430 (9% of the fleet) to 541 units (11% of the fleet). Deteriorated assets affect transmission system performance. The average transformer and autotransformer failures have increased over the past five years and elevated the risk to serving load and in some cases autotransformer failures are jeopardizing the security of the bulk transmission system. The duration of forced outages due to circuit breakers has increased over the past decade primarily due to the number of ABCB-related forced outages.

Stations Renewal investments contain critical investments necessary to preserve transmission system performance and reliability of provincial power system. The key Stations Renewal work is as follows:

- The proposed plan contains 35 investments to address assets that are in poor condition, have inadequate performance or are obsolete, at 30 transmission network stations. Network stations are the backbone of the transmission system in Ontario and responsible for transferring electricity across the province from generation sources such as nuclear or hydroelectric to load centers. The assets in these stations operate at bulk transmission level voltages (i.e. 500kV, 230kV, and 115kV). 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 NPCC. Investments in network stations are driven by station asset condition and prioritized based on safety, compliance, reliability and environmental impacts. Further details can be found in TSP Section 2.11, T-SR-01.

- There are 11 investments that target replacements of poor performing ABCBs and components that are in poor condition, have inadequate performance or are obsolete, at 9 transmission network stations. The ABCB population experienced the greatest number of air system component failures. In some cases, such failures led to breaker fail protection operations that forced the tripping (opening) of adjacent breakers. This can cause interruptions to circuits and busses, which could give rise to transmission customer outages. These performance issues have also resulted in multiple instances where generators were forced offline. Given the criticality of network stations, Hydro One plans to replace all of its ABCB fleet. Further details can be found in TSP Section 2.11, T-SR-02.
- There are 102 investments to address assets that are in poor condition, have inadequate performance or are obsolete, at 93 connection stations. Connection stations are a critical component in regional supply systems serving local areas. 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. The LDCs that are served by Hydro One's transmission system serve most of 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. Further details can be found in TSP Section 2.11, T-SR-03.

While there is a significant pool of poor condition assets, Hydro One paced its Stations renewal investments to deal with the most pressing system and asset needs. In addition, as discussed above, with nuclear retirements, refurbishments and contract expirations driving the need for capacity in late 2020, reinforcing transmission in key areas of the province is essential to maintaining reliability. As a result, the proposed renewal work at critical transmission stations is required to be undertaken to improve and ensure transfer capabilities needed to maintain system performance.

2.8.4.2 LINES RENEWAL

Lines renewal investments involve the replacement, as required, of poor condition overhead conductors, insulators, and wood poles, as well as coating of steel towers. These investments are required to sustain performance and reliability of the transmission system as well as mitigate safety concerns associated with poor condition assets. 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, line assets are also continuing to deteriorate, thereby posing an elevated risk of failure. Overhead conductor is the most vulnerable and critical component of transmission lines. Over the past four years, the number of poor condition overhead conductors has increased by 1,231 circuit-kms, from 2,643 circuit-kms (representing 9% of the conductor fleet) to 3,874 circuit-kms (14% of the conductor fleet). In addition, there are another 3,329 circuit-kms of overhead conductors (12% of overall population) exhibiting some form of deterioration. While these assets do not require replacement at this time, 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, thereby requiring replacement. There are other transmission line components (e.g., wood poles, 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 porcelain insulators that require immediate attention.

The biggest Lines Renewal investment is associated with line refurbishments. This investment is triggered by the confirmed need to replace the conductor or in a minority of cases, extensive structure deterioration. During the development of a line refurbishment investment, Hydro One also considers other line components for replacement such as insulators, wood poles, and shieldwires that have been confirmed to be in poor condition. The proposed renewal plan contains 16 individual investments that target the refurbishment of poor condition conductors and other components, 12 of which address deteriorated assets on circuits that form part of the bulk electricity system. The majority of circuits are located in publicly accessible areas, where a failure of the poor condition assets may pose significant 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. Hydro One is committed to ensuring reliable supply to all customers.

Similar to the stations renewal work, Hydro One has paced its lines investments to deal with the most pressing system and asset needs. The proposed lines investments address only 1,571 circuit-kms or 1.1% of the conductors in the fleet per year. The proposed plan is the minimum level of investments needed to maintain the system performance.

2.8.5 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. These investments are non-discretionary with the majority having been identified as a result of regional planning processes, IESO bulk planning studies or the 2017 Long-Term Energy Plan (2017 LTEP).[6]

System Service investments account for about $488M of gross capital expenditures over the five-year plan. However, some of these investments are recoverable from customers in accordance

[6] The 2017 LTEP recommended a total of sixteen projects. Detailed discussion relating to those projects was provided in EB-2019-0082 Exhibit B-1-1. Most of the projects are expected to be completed by 2022. Only four investments are expected to occur over the 2023-2027 plan period and account for a net capital expenditure $22.8M. Those projects are identified in Table 7.

with the Transmission System Code. The net capital impact is $461M or about 6% of the total net capital expenditures over the 2023-2027 period, as further detailed in Table 6 below.

Table 6 - System Service Capital Expenditure Summary

OEB Investment Category	Forecast (Planned $M)						
	2023	2024	2025	2026	2027	Total of Test Years	% of Portfolio
System Service	90.9	101.6	85.8	93.1	90.1	461.4	6%

The material System Service investments outlined in the TSP are listed in Table 7.

Table 7 - System Service Material Investments

ISD	Investment Title	2023	2024	2025	2026	2027
T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits[3]	-	-	-	-	-
T-SS-02	St. Lawrence TS: Phase Shifter Upgrade	6.0	-	-	-	-
T-SS-03	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade[2,3]	9.0	-	-	-	-
T-SS-04	Richview x Trafalgar 230kV Conductor Upgrade[2]	12.6	16.4	12.1	2.4	-
T-SS-05	Merivale TS: Add 230/115kV Autotransformers[1]	25.0	30.0	22.0	-	-
T-SS-06	Southwest GTA Transmission Reinforcement [1,2]	6.5	7.5	3.0	-	1.0
T-SS-07	West of Chatham Reinforcement[2]	8.3	20.4	5.2	-	-
T-SS-08	Future Transmission Regional Plans	10.7	20.0	20.4	20.4	20.4
T-SS-09	West of London Reinforcement[2]	4.2	4.2	18.7	60.9	54.8
Other System Service Investments		8.5	3.1	4.4	9.4	13.8
Total System Service		**90.9**	**101.6**	**85.8**	**93.1**	**90.1**

[1] Investment identified in the Regional Planning Process
[2] Investment that requires Leave to Construct Approval
[3] Investment identified in the 2017 Long-Term Energy Plan

Hydro One plans to invest $214M on inter-area capacity investments, with net capital expenditures of $192M over the planning period. These investments will provide new or upgraded transmission facilities to increase the transfer capability between within Ontario and with neighbouring utilities (see TSP Section 2.11, T-SS-01, T-SS-02, T-SS-03, T-SS-07 and T-SS-09). A significant driver of investment is the required reinforcements identified by the IESO as part of bulk planning studies for the West of Chatham and West of London transmission systems. The IESO has directed Hydro One to develop new 230kV transmission lines between Chatham and Lakeshore (West of Chatham), and Lambton and Chatham (West of London) because of unprecedented growth in the agricultural sector in the Windsor-Essex region of Southwest Ontario and the need to ensure the necessary bulk transfer capability to support growth in load and generation. The required station expansion to facilitate these new transmission lines represent 38% of the expenditures in this category and are detailed in TSP Section 2.11, T-SS-07 and T-SS-09 for West of Chatham, and West of London, respectively.

Hydro One also plans to invest about $234M (gross capital) in local area supply; with a net capital impact of $231M over the planning period. These investments will provide new or upgraded facilities to ensure area supply adequacy, and meet load forecast requirements in areas where existing transmission facility loading levels reach or exceed capacity (see TSP Section 2.11, T-SS-04, T-SS-05, T-SS-06, and T-SS-08).

Lastly, Hydro One plans to invest $14M in risk mitigation, and reliability enhancement. The majority of the projects in this category are below the material threshold. These investments will ensure compliance with mandatory standards, including customer delivery point performance, and demonstrate Hydro One’s responsiveness to customer concerns.

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 and by the third party analysis conducted by Clearspring Energy Advisors, LLC (Clearspring). Any impact on total OM&A must be considered in the context of the full 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 2023-2027 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.

Based on Hydro One's analysis, the proposed capital investments are not expected to yield significant savings to OM&A. Hydro One estimates Sustainment OM&A savings resulting from capital investments (once the new assets are all in-serviced) to be approximately $0.55M per year during the 2023-2027 period. In addition, Clearspring was unable to identify a clear, statistically significant, relationship between capital investments and OM&A costs. Based on Clearspring's analysis, two models indicated that OM&A spending increases as capital spending increases and one model indicated that as the capital age decreases (due to asset replacements), OM&A spending is decreased.

(i) Hydro One's Analysis

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.[7] 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-

[7] General Plant capital investments are not directly related to transmission power system assets and are not discussed here.

3% of each asset type).[8] 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 require routine preventive maintenance similar to older equipment, according to the same general frequency and maintenance activities. Hydro One must adhere to various manufacturer's 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. Furthermore, some preventive maintenance must be completed regardless of asset age, such as condition-driven refurbishment work, compliance-driven PCB remediation work, and right-of-way vegetation management.[9]

Thus, 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;[10] 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 1.1% of the fleet each year, the corresponding OM&A savings due to the difference in maintenance work is $0.1M.[11]

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[8] 3.3% of the transformer fleet per year, 2.5% of the breaker fleet per year, 3.4% of the protection fleet per year, 1.1% of the conductor fleet per year, 3.3% of the insulator fleet per year and 2.7% of the wood pole fleet per year.
[9] Subject to NERC's FAC-003 Transmission Vegetation Management standards.
[10] Three years for steel lines and every two years for wood lines.
[11] Approximately $2.8M is estimated to be saved over 25 years due to helicopter patrols on new lines, resulting in annual savings of $0.1M.

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 8 below, over the 2019-2020 period, 87% of the corrective defects occurred on the older portion of the major power system equipment (e.g. transformers, breakers, and lines) and 92% of the corrective expenditures were spent to fix those defects. Table 8 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. 1-3% of each asset type),[12] the corresponding corrective maintenance savings are expected to be approximately $0.45M per year.[13]

Table 8 - Corrective Maintenance – Old vs. New Equipment (2019-2020)

	Transformers		**Breakers**		**Lines**	
	New[14]	**Old**	**New**	**Old**	**New**	**Old**
Equipment Age	23%	77%	22%	78%	10%	90%
Corrective Defects (%)	20%	80%	12%	88%	7%	93%
Corrective Budget (%)	9%	91%	9%	91%	6%	94%

As Hydro One replaces equipment with newer technology and improved designs, there are certain savings in preventive and corrective maintenance costs, primarily resulting from equipment that (i) is less prone to breakdowns than the older technology (e.g. new sulfur

[12] 3.3% of the transformer fleet per year, 2.3% of the breaker fleet per year and 1.1% of the conductor fleet per year.
[13] For Lines, during 2019-2020 the corrective cost per km was $85 for old lines and $48 for new lines. Hydro One plans to replace 1,571 km of poor condition lines, resulting in annual savings of $0.05M per year when these lines are in-serviced. For transformers, during 2019-2020 the corrective cost per unit was $6,110 for new units and $17,110 for old units. Hydro One plans to replace about 24 units per year, resulting in annual savings of $0.27M per year when these units are in-serviced. For breakers, during 2019-2020 the corrective cost per unit was $525 for new units and $1,600 for old units. Hydro One plans to replace about 121 units per year, resulting in annual savings of $0.13M per year when these units are in-serviced.
[14] 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.

hexafluoride (SF6) breakers compared to old air-blast 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,[15] and (ii) an increase in the number of protection systems due to NPCC standards[16] that require duplicated protection schemes to provide redundancy.

(ii) Third Party Research on Capital Investments and OM&A Costs

As part of its benchmarking and productivity research (further discussed in Exhibit A-04-01, Attachment 1), Clearspring compared Hydro One's capital age of transmission assets relative to the industry (see Section 5.3 of the report) and assessed whether there is any correlation between transmission capital investments and OM&A costs (see Section 7 of the Report).

Similar to Hydro One's analysis, Clearspring also found that "there may be lengthy lags between when capital increases and when those investments result in OM&A cost savings. Further, increased capital investments may signal the utility doing more for its customers … and this increased output could also translate into higher OM&A expenses rather than a reduction. As the capital age research can also show, increased capital investments do not necessarily mean that

[15] 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.
[16] Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directories #4 (System Protection Criteria) and #7 (Remedial Action Schemes)

the capital age of the system is being refreshed. If those increased capital investments are merely maintaining the system age, it would not be expected that OM&A expenses would decline since the capital age is not being reduced by the investments."[17]

Clearspring developed three models to understand whether there is any correlation between transmission capital investments and OM&A costs but was unable to determine any clear relationship in their research. Models 1 and 2 indicated that OM&A spending increases as capital spending increases but with a low level of statistical confidence.[18] Model 3 provided a view of when the capital age change is lagged by five years and the OM&A spending change takes place over the subsequent five-year period. Model 3 indicated that as the capital age increases, OM&A spending is increased, or, conversely, as the capital age decreases, OM&A spending is decreased. However, this, too, was not a statistically significant.[19]

Thus, Clearspring concluded that the "models do not display a consistent empirical story and do not provide evidence that OM&A spending should be expected to decrease as the capital age of the system gets younger through increased capital spending."[20] Clearspring found that Hydro One's transmission capital age is significantly older than the industry benchmark and that "the proposed capital investment levels are not expected to reduce [Hydro One Transmissions] system age substantially. [In fact,] Hydro One's transmission capital age is … projected to get slightly older from 2023 to 2027… and remains substantially higher than the U.S. industry's aggregated transmission capital age in 2019."[21]

[17] Exhibit A-04-01 Attachment 1, Section 7, p 69.
[18] Exhibit A-04-01 Attachment 1, Section 7, p 70-71.
[19] Exhibit A-04-01 Attachment 1, Section 7, p 71.
[20] Exhibit A-04-01 Attachment 1, Section 7, p 73.
[21] Exhibit A-04-01 Attachment 1, Section 7, p 73.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2023*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var	Plan	Forecast[2]	Var					
			%			%			%			%			%					
System Access	24.3	33.7	39%		46.2	--	24.8	19.5	-21%	11.3	40.1	256%	11.7	31.5	168%	79.4	70.9	59.8	36.5	50.1
System Renewal	780.4	776.2	-1%		792.6	--	810.1	804.0	-1%	982.8	739.6	-25%	958.2	971.5	1%	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0
System Service*	75.6	73.9	-2%		85.6	--	198.4	196.1	-1%	148.2	223.9	51%	151.8	122.0	-20%	90.9	101.6	85.8	93.1	90.1
General Plant	119.7	83.6	-30%		92.1	--	111.1	124.7	12%	94.4	137.8	46%	94.7	102.8	9%	146.8	124.0	114.2	115.9	105.0
Progressive Productivity							- 17.0			- 39.0			- 61.0	- 48.1		- 61.0	- 61.0	- 61.0	- 61.0	- 61.0
Other**							- 25.5			- 28.4			- 29.1							
TOTAL EXPENDITURE	1,000.0	967.3	-3%	-	1,016.5	--	1,101.9	1,144.4	4%	1,169.2	1,141.5	-2%	1,126.4	1,179.7	5%	1,434.0	1,463.9	1,450.4	1,461.8	1,448.2
System O&M***	$ 394.3	$ 419.2	6%		$ 357.9	--	$ 385.0	$ 398.5	3%		$ 389.0	--		$ 393.4	--	$ 420.5				

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

** Includes OPEB, pension and compensation directive adjustments.

*** System O&M reflects total Operations, Maintenance and Administration expenses. 2024 - 2027 is determined based on the escalation factor identified in Exhibit A-04-02.

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
TSP Section 2.9
Notes on year over year Plan vs. Actual variances for Total Expenditures
TSP Section 2.9
Notes on Plan vs. Actual variance trends for individual expenditure categories
TSP Section 2.9

SECTION 2.9 - TSP - CAPITAL EXPENDITURES TRENDS AND VARIANCES

2.9.1 INTRODUCTION

As described in TSP Section 2.8, over the 2023-2027 planning period, Hydro One plans to invest in the expansion, renewal and reinforcement of its transmission system. The proposed investments are required to maintain transmission reliability performance, to address customer needs and preferences, and to mitigate asset and operational risks by accomplishing the planned capital work. The overall trend of the capital expenditures as it compared to the historical years is as follows:

- **System Access** – Capital expenditures over the test years are forecast to increase compared to historical levels as a number of investments, including customer connection projects in Southwest Ontario and third party relocations that are non-discretionary to meet Hydro One's legislative obligations.
- **System Renewal** – Capital expenditures increase compared to historical levels as a result of the need to address critical transmission assets. System Renewal investments are required to address assets that have failed, are in poor condition (as indicated by condition assessments), have inadequate performance, or are functionally obsolete and ensure safety, mitigate reliability risk and maintain compliance with regulatory, environmental and reliability standards.
- **System Service** – Capital expenditures decrease compared to historical levels as a result of the modified scope of some of the projects, as further described below. Pursuant to Hydro One's obligations under its electricity transmission licence and Transmission System Code, these investments are mandatory, and required to ensure local area supply adequacy, and to mitigate system risks related to safety, security and reliability.

For each category of System Access, System Renewal and System Service, this section first discusses variances between the OEB approved 2020-2022 spending levels versus the 2020-2021 historical actuals and forecast, and the 2022 Bridge year forecast since Hydro One's most recent transmission rate filing (EB-2019-0082) (see TSP Section 2.9.2 Historical Capital

Expenditures Trends and Variances below). Following the discussion of historical trends and variances, TSP Section 2.9.3 (Forecast Capital Expenditure Trends) provides a ten year view of Hydro One's capital expenditures and discusses trends and variances over the historical and bridge years.

In addition, this section provides, in response to the OEB direction, a comparison of all investments requiring Leave to Construct (LTC) approvals in TSP Section 2.9.4 (Leave To Construct Projects Trends And Variances), between what was approved in the LTC applications and what was budgeted into capital expenditures for the Test years, and provides explanations of any material variances regarding scope, cost or schedule.[1]

For trends and variance discussion pertaining to the Transmission OM&A, refer to Exhibit E-02-01.

2.9.2 HISTORICAL CAPITAL EXPENDITURES TRENDS AND VARIANCES

This section provides a summary of Hydro One's historical capital expenditures and bridge year forecasts in comparison to the levels approved during Hydro One's most recent transmission rate filing (EB-2019-0082).

Hydro One's historical actuals and forecast capital spending relative to OEB-approved amounts are shown in Table 1 below.

[1] EB-2019-0082, OEB Decision and Order, p. 182.

1 **Table 1 - Historical and Bridge Years Capital Expenditure Summary**

OEB Category	Historical (Previous Plan and Actual / Forecast)												Bridge		
	2018			2019			2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Access	24.3	33.7	39%	-	46.2	-	24.8	19.5	-21%	11.3	40.1	256%	11.7	31.5	168%
System Renewal	780.4	776.2	-1%	-	792.6	-	810.1	804.0	-1%	982.8	739.6	-25%	958.2	971.5	1%
System Service[2]	75.6	73.9	-2%	-	85.6	-	198.4	196.1	-1%	148.2	223.9	51%	151.8	122.0	-20%
General Plant	119.7	83.6	-30%	-	92.1	-	111.1	124.7	12%	94.4	137.8	46%	94.7	102.8	9%
Subtotal	**1000.0**	**967.3**	**-3%**	**-**	**1016.5**	**-**	**1144.4**	**1144.4**	**0%**	**1236.6**	**1141.5**	**-8%**	**1216.5**	**1227.8**	**1%**
Productivity[3]	0.0	0.0	-	-	0.0	-	-17.0	0.0	-	-39.0	0.0	-	-61.0	-48.1	-21%
Other[4]	0.0	0.0	-	-	0.0	-	-25.5	0.0	-	-28.4	0.0	-	-29.1	0.0	-
Total	**1000.0**	**967.3**	**-3%**	**-**	**1016.5**	**-**	**1101.9**	**1144.4**	**4%**	**1169.2**	**1141.5**	**-2%**	**1126.4**	**1179.7**	**5%**
System OM&A[5]	394.3	419.2	6%		357.9		385.0	398.5	3%		389.0			393.4	

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[2] The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan). Hydro One submitted an application with the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169). Further information may be found in TSP Section 2.8.
[3] Progressive productivity represents commitments made during the 2020-22 transmission rate application for 2022 that are sustained through the test period. Incremental productivity reductions for JRAP are applied to revenue requirement via productivity stretch factors, as described within the SPF Section 1.4.
[4] OEB Approved includes OPEB, pension and compensation directive adjustments.
[5] System OM&A reflects total Operations, Maintenance and Administration expenses. Further information is provided in Exhibits E-02-01.

Over the 2020-2022 period, the capital plan will be delivered within 2% of the OEB-approved envelopes, as shown in Table 1. Variances to plan reflect the implementation and operationalization of productivity initiatives consistent with the progressive productivity framework described in SPF Section 1.4, a redirection to General Plant and adjustments associated with updates to OPEB, pension and compensation directives, which materialize in actual costs. Variances to OEB categories, on a multi-year basis, reflect trade-offs required to accommodate the need and timing of customer and third party growth through System Access investments, as well as system needs identified through the IESO's provincial integrated planning processes which lead to the development and implementation of System Service investments. Details pertaining to General Plant capital expenditures may be found in GSP Section 4.9.

As the need and timing of investments driven by external factors evolves, Hydro One endeavours to deliver a capital portfolio which is consistent with the OEB-approved levels at the overall envelope level, and on a multi-year basis. The variance for the 2020-2022 period reflects the increased complexity of the Lakeshore TS investment, driven by incremental requirements identified by the IESO; this System Service investment is a key component of the near-term Leamington Area Transmission Reinforcement required to enable significant growth in Southwest Ontario.

The year-over-year variation reflects Hydro One's commitment to maintain overall investment levels within the envelope approved in Hydro One's 2020-2022 transmission rates application, while responding to external investment drivers and system pressures.

2.9.2.1 SYSTEM ACCESS

Table 2 below presents historical capital expenditures for System Access.

Table 2 - System Access

OEB Category	Historical (Previous Plan and Actual / Forecast)						Bridge		
	2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%
System Access[2]	24.8	19.5	-21%	11.3	40.1	256%	11.7	31.5	168%

Over the 2020-2022 period, System Access investments are anticipated to be approximately $43M (91%) above planned spending levels,[6] as a result of higher demand for new customer connections and third party relocations, including:

- new customer facilities in northern Ontario to enable mining operations;
- new connection facilities in Southwest Ontario, including Leamington TS #2, South Middle Road TS #1; and
- new customer connections in the greater Toronto areas, including those related to data centres.

The re-pacing of customer driven projects, including the connection of northern Ontario mining operations and customer connections in the Toronto area, drove the variance in 2020 as project schedules were aligned with customer schedules. New connection facilities in southwestern Ontario, including Leamington TS #2 and South Middle Road TS #1, and transmission facility relocations in support of Metrolinx along with the re-paced investments from 2020 resulted in an increase in expenditures in 2021 and 2022 above approved levels.

[6] The variance reflects decreased expenditures due to productivity initiatives and other adjustments (e.g. OPEB, pension and compensation directive adjustments).

2.9.2.2 SYSTEM RENEWAL

Table 3 - System Renewal

OEB Category	Historical (Previous Plan and Actual / Forecast)						Bridge		
	2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%
System Renewal	810.1	804.0	-1%	982.8	739.6	-25%	958.2	971.5	1%

Over the 2020-22 period, System Renewal investments are forecasted to be approximately $236M (9%) below approved levels, however the variance reflects decreased expenditures due to productivity initiatives and other adjustments (e.g., OPEB, pension and compensation directive adjustments). The variance is primarily driven by redirections across OEB categories to accommodate emerging, mandatory system growth investments and required system upgrades as well as to enable improved business outcomes through General Plant investments. The redirections primarily account for $21M variance to System Access and a $53M variance to System Service and General Plant investment categories.

Contributors to this variance include:

- Revised costs and timing for underground cable replacements in downtown Toronto, reflecting a lower total cost relative to the prior application resulting in decreased spending of $30M over 2020-2022.;
- Bundling of transmission line refurbishment work coordinated with customer upgrades in northern Ontario, reflecting a comparable increase to System Access and decrease to System Renewal in 2022 (i.e. the $21M in redirections discussed above);
- Revised costs and timings of line refurbishment projects and lower spend for transmission line component replacement program, including shieldwire and insulator replacements;

- Refined maturity and pacing of station reinvestments, including investments to replace air blast circuit breakers at critical facilities interfacing with nuclear generators, such as Bruce A/B and Pickering resulting reduced expenditures in 2021.

These lower forecast expenditures are anticipated to maintain the overall investment levels in a manner consistent with the envelope approved in Hydro One's 2020-22 transmission rates application, accounting for externally driven factors, and responding to verified asset and system conditions.

2.9.2.3 SYSTEM SERVICE

Table 4 presents historical capital expenditures for System Service.

Table 4 - System Service

OEB Category	Historical (Previous Plan and Actual / Forecast)						Bridge		
	2020			2021			2022		
	OEB Approved	Actual	Variance	OEB Approved	Forecast	Variance	OEB Approved	Forecast	Variance
	$M	$M	%	$M	$M	%	$M	$M	%
System Service[2]	198.4	196.1	-1%	148.2	223.9	51%	151.8	122.0	-20%

Over the 2020-2022 period, System Service investments are forecast to be approximately $43.6M (8.7%) above planned spending levels.[7] Expenditures in 2020 were in line with approved amounts. This overage is partially mitigated through the exclusion of new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan), which are expected to be owned by newly licenced partnerships. Further information may be found in TSP Section 2.8. The variance in 2021 is primarily due to the increased scope, complexity and cost associated with the Lakeshore TS project and schedule extensions and increased costs associated with

[7] The variance reflects decreased expenditures due to productivity initiatives and other adjustments (e.g. OPEB, pension and compensation directive adjustments).

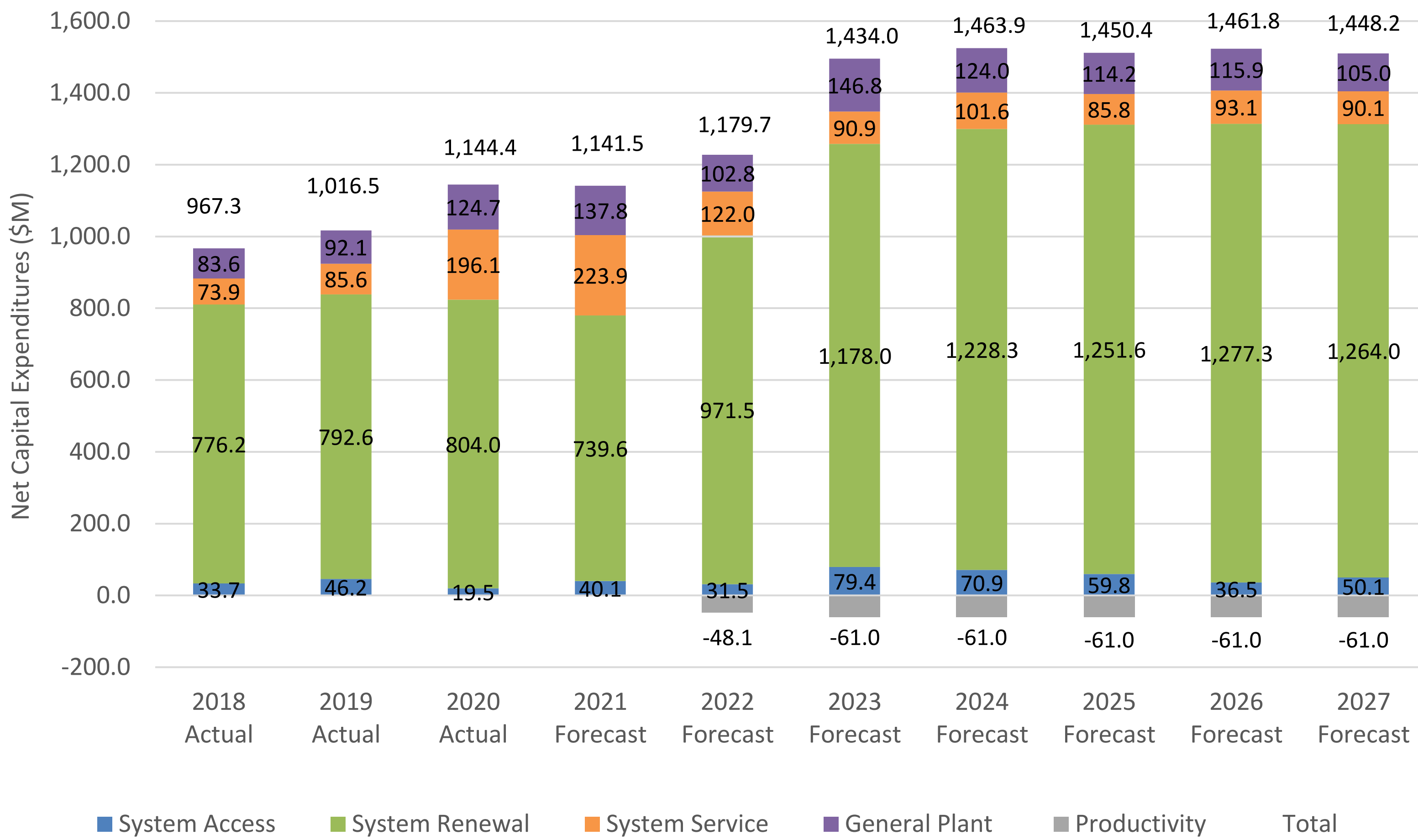
delays to NextBridge's East-West Tie line construction. The lower forecast expenditures in 2022 are anticipated to maintain overall investment levels within the envelope approved in Hydro One's 2020-22 transmission rates application.

2.9.3 FORECAST CAPITAL EXPENDITURES TRENDS

Over the 2023-2027 period, Hydro One plans to invest an average of $1,452M per year in Transmission capital, for a total of approximately $7,258M to maintain transmission reliability performance, to address customer needs and preferences, and to mitigate asset and operational risks by accomplishing the planned capital work. Hydro One's historical capital spending relative to the 2023-2027 amounts is shown in Table 5 and Figure 1.

Table 5 - Ten-year Capital Plan

OEB Category	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
System Access	33.7	46.2	19.5	40.1	31.5	79.4	70.9	59.8	36.5	50.1
System Renewal	776.2	792.6	804.0	739.6	971.5	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0
System Service	73.9	85.6	196.1	223.9	122.0	90.9	101.6	85.8	93.1	90.1
General Plant	83.6	92.1	124.7	137.8	102.8	146.8	124.0	114.2	115.9	105.0
Productivity	0.0	0.0	0.0	0.0	-48.1	-61.0	-61.0	-61.0	-61.0	-61.0
Total	**967.3**	**1,016.5**	**1,144.4**	**1,141.5**	**1,179.7**	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**



1 **Figure 1: Ten-year Capital Plan**

The overall trend of the capital expenditures as it compared to the historical years is as follows:

2.9.3.1 System Access

Table 6 – System Access

OEB Category	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
System Access	33.7	46.2	19.5	40.1	31.5	79.4	70.9	59.8	36.5	50.1

2023-2027 forecast expenditures for System Access are expected to be higher than prior OEB approved capital expenditures and actual historical expenditures for the 2018-2022 period. The increase is driven by customer expansions west of Chatham and industrial customers in northern Ontario.

The forecast increase is related to the Build Leamington Area Transformer Station investment (T-SA-10), which represents $129M over the 2023-2027 forecast period. This investment is driven by the expansion of the agricultural sector within Southwest Ontario with the need for customer connections increasing in tandem. Consequently this investment includes three additional stations in the west of Chatham region.

System Access investments are non-discretionary investments driven by service obligations, including requirements of the TSC and conditions of Hydro One's transmitter licence. Hydro One must respond and connect new load and generation customers, and address transmission system modifications to accommodate third party requests.

2.9.3.2 System Renewal

Table 7 - System Renewal

OEB Category	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
System Renewal	776.2	792.6	804.0	739.6	971.5	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0

2023-2027 forecast expenditures for System Renewal are expected to be higher than prior OEB approved capital expenditures and actual historical expenditures for the 2018-2022 period. System Renewal investments continue to represent the largest share of the proposed capital expenditures.

Hydro One needs to manage and renew a large population of deteriorating assets to maintain the system's performance and reliability. Investment decisions are underpinned by verified asset condition and have been selected based on condition, performance and obsolescence criteria, considering customer needs and preferences and equipment right-sizing, and have been prioritized through a rigorous investment planning process. Hydro One's priority is to ensure transmission facilities remain in-service. The 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.

With respect to asset condition, over 10% of all major transmission assets are in poor condition. While the approach to asset management is grounded in proactive condition-based replacement decisions, the asset fleet continues to deteriorate and replacement rates are not keeping pace. In the near term, significant investment would be required to address the entire pool of deteriorated assets, which is not feasible from a cost or resource perspective. Hydro One has adopted a paced approach, targeted to deliver outcomes consistent with customer preferences.

Contributing to the increase over historical spend is an increased focus on the following System Renewal investments:

- Transmission Station Renewal – Network Stations (TSP Section 2.11, T-SR-01), represents $994M over the 2023-2027 period. Investments in network stations are critical to ensure bulk system reliability and maintain compliance with reliability standards issued by NERC, NPCC, the IESO, or other external regulatory entities.
- Transmission Station Renewal – Air Blast Circuit Breakers (TSP Section 2.11, T-SR-02), represents $576M over the 2023-2027 period. The TSP reflects the continued emphasis on the replacement of air blast circuit breakers, the poorest performing breakers in the fleet and installed at critical bulk transmission facilities.
- Transmission Station Renewal – Connection Stations (TSP Section 2.11, T-SR-03), represents $1,877M over the 2023-2027 period. Connection Stations directly supply industrial and commercial customers and local distribution companies. Investments in network stations, which form the backbone of bulk transmission system, benefit all Ontarians given the asset deterioration and need at these stations.
- Transmission Line Complete Refurbishment (TSP Section 2.11, T-SR-13), representing $833M over the 2023-2027 forecast period. These transmission lines directly supply customers, LDCs and stations; and through condition assessment have been found to be in poor condition.
- Transmission Line Insulator Replacement (TSP Section 2.11, T-SR-08), represents $400M and Wood Pole Structure Replacement (TSP Section 2.11, T-SR-04) represents $294M over the 2023-2027 period. Proactive replacement of these assets is necessary to maintain public safety, and customer and system reliability.

- Legacy SONET Replacement (TSP Section 2.11, T-SR-11), represents $114M, and Optical Ground Wire (OPGW) Infrastructure Projects (TSP Section 2.11, T-SR-17) represents $117M over the 2023-2027 period. The SONET is a critical communication network that is essential for the safe and reliable operation of the transmission system. The primary trigger of this investment is technological obsolescence and is expected to improve reliability of Hydro One's power system telecom system serving teleprotection and supervisory control systems. There are also a number smaller OPGW infrastructure projects. These installations will eliminate gaps, provide additional geographic diversity and increase coverage of the existing fibre network serving power system telecom applications.

Hydro One’s System Renewal investments, while discretionary, are required to address assets in deteriorated condition and have been paced to balance risk and cost in a manner that aims to maintain system and customer reliability through pro-active condition based replacement.

2.9.3.3 System Service

Table 8 - System Service

OEB Category	Historical Actual/Forecast ($M)				Bridge Forecast ($M)	Forecast Period (Planned $M)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
System Service	73.9	85.6	196.2	223.9	122.0	90.9	101.6	85.8	93.1	90.1

2023-2027 forecast expenditures for System Service are decreasing compared to the actual amounts spent during the historical 2018 to 2022 period. The decrease is driven by the scope and timing of investments included in the application that will be owned by Hydro One. Although pockets of growth are expected, the application excludes the transmission lines expected to be owned by newly licenced partnerships.[8] The forecast includes continued

[8] Hydro One has excluded the lines capital expenditures from the 2023-2027 System Service forecast related to transmission lines that are expected to be owned by newly licenced partnerships. The stations

investment to ensure local area supply adequacy and mitigate system risks related to safety, security and reliability.

In 2019, the IESO completed a bulk system study for the West of Chatham region[9] that identified two recommendations to support the growth and expansion being seen in the region. The first was the construction of a new switching station, Lakeshore TS, which is slated for completion mid-2022, and the second was the construction of a new double-circuit 230kV transmission line from Chatham SS to Lakeshore TS. Some of this work is captured in the following investments:

- West of Chatham Reinforcement (TSP Section 2.11, T-SS-07), represents $34M over the 2023-2027 period. Development work on the new transmission line is currently underway[10] as well as the necessary station upgrades to facilitate this connection.
- West of London Transmission Reinforcement (TSP Section 2.11, T-SS-09), represents $143M over the 2023-2027 period. It is expected that the IESO will publish a bulk study for the West of London region in 2021 where it will recommend the construction of two new double-circuit 230kV transmission lines to further reinforce the transmission system in the south west.[11] These expenditures reflect the expansion and connection work at terminal network stations to facilitate the connection of the new transmission line.[10]

Hydro One's System Service investments are mostly non-discretionary and required to address system needs identified through regional planning, bulk planning studies, or the long-term energy plans.

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capital expenditures have been included as these are expected to be owned by Hydro One. Further information may be found in TSP Section 2.8.

[9] "*Need for Bulk Transmission Reinforcement in the Windsor-Essex Region*", IESO, June 13, 2019

[10] The transmission line is expected to be owned by a newly licenced partnership. Hydro One has excluded the lines capital expenditures from the 2023-2027 System Service forecast. The stations capital expenditures have been included as these are expected to be owned by Hydro One. Further information may be found in TSP Section 2.8

[11] Electricity Planning in the West of London Area, IESO Presentation, November 26, 2020.

2.9.4 LEAVE TO CONSTRUCT PROJECTS (LTC) TRENDS AND VARIANCES

As directed in the Decision and Order for EB-2019-0082, Table 9 below lists all projects for which a leave to construct application has been approved where capital expenditures are forecast during the test period.

Hydro One has a mature project delivery process with strong oversight and governance. Hydro One's capital project execution has been independently reviewed by UMS Group (see TSP Section 2.3, Attachment 1), which concluded that overall Hydro One has a mature project delivery process that performs well relative to industry peers.

As the LTC approved project's scope, design and execution are further defined throughout the project delivery process, cost and schedule accuracy improves. Thus, since the LTC projects were approved by the OEB, they have been further defined as they progressed through the project delivery process, resulting in project cost and schedule accuracy improving. Further information about the project delivery process may be found in TSP Section 2.10.

Table 9 - LTC Approved Projects vs Forecast Expenditures in Test Years

S92 OEB Case	ISD Ref.	Project	S92 Project Total ($M)	S92 Filed In-Service Date	TSP Forecast Total ($M)	TSP Forecast In-Service Date
EB-2020-0188	T-SR-18	Power Downtown Toronto (C5E/C7E)	$107.8	Q4 2024	$108.8	Q1 2025
EB-2018-0257	T-SA-02 (T2R/Timmins TS)	Côté Lake Mine Connection Project (IAMGOLD)	$71.8	T2R/Timmins TS: Q3 2020	$65.1	T2R/Timmins TS: Q3 2023
EB-2021-0136*	T-SS-04	Richview x Trafalgar Reconductoring Project	$59.0	Q2 2026	$53.2	Q1 2026

**This S92 proceeding is ongoing and final approval is pending.*

Power Downtown Toronto Project: No material variance to schedule, scope, or cost has been forecast during the Test period relative to the approved leave to construct application.

Côté Lake Mine Connection Project: The project has been delayed by two years due to external factors driven by the customer. However, actual project costs are estimated to be about $6.7M lower than in the S92 application due to lower than anticipated line costs for access road construction, tower crane pads installation, soil removal and site restorations.

Richview x Trafalgar Reconductoring Project: The S92 project costs are higher than the costs included in this application. The forecast cost was prepared earlier as part of the approved business plan underpinning this transmission application. The S92 application filed in June 2021 reflects subsequent updates to the project scope that identified the need to build additional access roads and tower crane pads for carrying out the line conductor replacement work.

Appendix 2-AA
Capital Projects Table ($M)

Projects	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Test	2024 Test	2025 Test	2026 Test	2027 Test
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
System Access										
Generator Customer Connection	0.3	0.5	2.2	1.3	0.0	0.0	0.0	0.0	0.0	0.0
Load Customer Connection	28.5	40.1	18.4	38.3	25.9	41.6	68.1	57.0	35.6	49.3
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	4.4	5.9	-1.7	0.5	5.5	37.8	2.8	2.8	0.8	0.8
P&C Enablement for Generation Connections	0.5	-0.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	33.7	46.2	19.5	40.1	31.5	79.4	70.9	59.8	36.5	50.1
System Renewal										
Ancillary Systems	0.7	0.1	-15.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Circuit Breakers	0.1	1.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Integrated Station Investment	410.7	426.8	499.7	359.8	512.5	733.3	722.5	699.6	698.3	728.8
IT Security	22.9	24.5	35.9	40.9	34.4	0.0	0.0	0.0	0.0	0.0
Other Power Equipment	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Overhead Lines Refurbishment Projects, Component Replacement Programs	221.2	230.5	196.0	243.8	297.2	271.2	338.5	406.0	455.1	438.4
Power Transformers	-0.7	-2.7	-2.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Protection and Automation	21.6	18.6	14.4	29.6	54.5	81.6	88.4	87.5	68.9	36.1
Site Facilities and Infrastructure	0.3	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tx Transformers Demand and Spares	82.6	78.2	68.3	51.3	45.4	50.7	51.5	52.2	53.2	54.1
Underground Lines Cable Refurbishment & Replacement	16.5	14.9	7.1	14.2	27.6	41.1	27.4	6.4	1.9	6.6
Sub-Total	776.1	792.6	804.0	739.6	971.5	1,178.0	1,228.3	1,251.6	1,277.3	1,264.0
System Service*										
Inter Area Network Transfer Capability	48.9	57.9	144.8	174.4	86.2	31.5	25.1	24.5	65.4	60.4
Local Area Supply Adequacy	20.7	19.7	41.6	44.9	34.1	54.9	74.0	58.8	25.8	27.7
Performance Enhancement	0.0	0.6	3.2	0.7	1.2	2.5	0.5	0.5	0.0	0.0
Power Quality	1.4	3.1	1.9	0.8	0.1	0.0	0.0	0.0	0.0	0.0
Risk Mitigation	2.6	4.2	4.6	3.2	0.5	2.0	2.0	2.0	2.0	2.0
Smart Grid	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	73.9	85.6	196.1	223.9	122.0	90.9	101.6	85.8	93.1	90.1
General Plant										
Fleet	9.3	15.0	13.5	14.4	14.9	25.8	26.4	26.7	27.0	27.9
Facilities & Real Estate	23.4	16.0	19.7	15.4	15.5	26.0	24.9	17.5	18.2	14.8
Information Technology	42.0	47.1	42.2	30.1	29.1	57.4	46.5	45.0	43.7	35.9
System Operations	3.8	6.0	38.8	59.0	21.8	12.0	3.8	4.2	4.8	4.2
Operating Infrastructure	5.8	8.7	7.5	18.9	21.5	25.5	22.4	20.9	22.2	22.3
Other	-0.7	-0.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Total	83.6	92.1	124.7	137.8	102.8	146.8	124.0	114.2	115.9	105.0
Progressive Productivity					-48.1	-61.0	-61.0	-61.0	-61.0	-61.0
Total	**967.3**	**1,016.5**	**1,144.4**	**1,141.5**	**1,179.7**	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***										
Total	**967.3**	**1,016.5**	**1,144.4**	**1,141.5**	**1,179.7**	**1,434.0**	**1,463.9**	**1,450.4**	**1,461.8**	**1,448.2**

* The 2019-2022 Actuals exclude new transmission line facilities for Chatham and Lakeshore (West of Chatham), Lambton and Chatham (West of London) and Northwest Bulk Transmission Line Project (Waasigan).

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital

CAPITAL PROGRAM PERFORMANCE REPORT – 2020

1.0 INTRODUCTION

This Capital Program Performance Report provides an overview of Hydro One's performance in 2020 in relation to the overall transmission capital envelope and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) and demonstrates that Hydro One has delivered its capital plan both in terms of expenditures and in-service additions.

This report is broken down into two main sections. Section Two focuses on performance at the overall envelope and OEB category level, demonstrating Hydro One's ability to successfully manage to the overall capital envelope in terms of both capital expenditures and ISA. Section Three focuses on performance at the project and program level and outlines the approach used by Hydro One to manage projects and programs. The projects and programs included in this report have material (greater than or equal to $3M) actual or planned ISA in 2020.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

At an envelope level, Hydro One performed very well both in terms of capital expenditure and in-service additions in 2020. This is evidenced in Table 1 below, which shows that Hydro One's 2020 capital expenditures were within 3.9% of the DRO Plan and in-service additions were within 1.5% of the DRO Plan.[1] The primary focus of this report is on the System Access, System Renewal, and System Service categories.[2]

[1] The DRO Plan refers to the OEB approved amounts for capital expenditures and ISA in EB-2019-0082.
[2] Performance in the General Plant category is described in GSP Section 3.9 Attachment 2.

Table 1 - 2020 Capital Expenditures and In-Service Additions

	Capital Expenditures 2020			In-Service Additions 2020		
OEB Category	**DRO Plan ($M)**	**Actuals ($M)**	**Variance (%)**	**DRO Plan ($M)**	**Actuals ($M)**	**Variance (%)**
System Access	24.8	19.5	-21.4%	8.6	7.2	-16.3%
System Renewal	810.1	804.0	-0.8%	821.3	824.5	0.4%
System Service	198.4	196.2	-1.1%	54.2	32.6	-39.9%
General Plant	111.1	124.7	12.2%	75.1	79.9	6.4%
Subtotal	**1,144.4**	**1,144.4**	**0.0%**	**959.2**	**944.3**	**-1.6%**
Productivity	-17.0			-15.8		
Other[3]	-25.5			-12.9		
Grand Total	**1,101.9**	**1,144.4**	**3.9%**	**930.5**	**944.3**	**1.5%**

This success is due in part to the improved project definition process and tools, which have improved the overall predictability of projects (see TSP Section 2.10). Hydro One's overall portfolio targets are a summation of many complex projects/programs. The company's ability to make project/program level changes in response to changing system needs and conditions has contributed to the achievement of the capital work program.

At the OEB category level there were various puts and takes which largely offset one another in the overall envelope as shown in Table 1 above. The System Access category had 2020 capital expenditure and in-service additions lower than budget primarily due to customer delays on the Seaton MTS 230 kV Transmission Supply to New 28 kV DESN project, the IAMGOLD - 115 kV Mine Connection project, and the NOVA Corunna CTS - Relocate T2 and Connect AST2 project. The System Renewal category had various puts and takes but at an aggregate level had capital expenditure and in-service additions in line with the budgeted values. The System Service category had reduced in-service additions in 2020 primarily due to the Lennox TS 500kV Shunt

[3] Includes OPEB, pension and compensation directive adjustments

Reactors project, which experienced equipment delays and outage issues that delayed a partial in-service addition into early 2021.

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, fully realizing that, inevitability, there will be changes at both the project and program levels. Individual variances, be it an annual or project total level are normal and are to be expected given the magnitude and complexity of the work being performed. As explained in TSP Section 2.10, each project involves a unique combination of elements related to the included work and site conditions and is undertaken pursuant to a defined project delivery process with budget tolerance as defined by the AACE class of estimate.[4] Projects are typically released for execution and funded based on a Class 3 estimate, which is further discussed below.

At Hydro One, projects are managed with a focus on adherence to the total project budget. So long as the project is delivered within its approved budget, adherence to a project's annual budget is viewed as less of a performance indicator because changes in outages, system conditions, resourcing, and other factors can require that projects be advanced or delayed.

Measuring against a project's total budget and schedule is more appropriate than an annual view because that is when the full benefit of the project is realized in terms of system capacity, resiliency, etc. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances, which more truly reflect project performance than in-year budget adherence. Programs are different in that they renew annually and are managed against annual budgets. As such, program performance is discussed in the context of adherence to annual budgets.

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[4] AACE estimate classification is discussed in TSP Section 2.10.

In summary, the focus of this report is as follows:

- Adherence to the overall capital envelope for the given year as demonstrated and discussed above;
- Project performance in relation to approved project total budgets, not annual budgets;
- Program performance in relation to annual budgets.

Figure 1 below illustrates 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 2020. This figure shows a tight dispersion of variances, which demonstrates Hydro One's overall effectiveness in executing projects while adhering to the overall project budget. The blue vertical lines in the cost variance chart are placed at -20% and +30% which is the range of expected outcomes for an AACE Class 3 estimate, and representative of the typical project definition work completed at the time of business case approval at Hydro One. Use of a Class 3 estimate to establish the appropriate range for completed projects is reasonable as that is the basis on which the project are funded, and it is consistent with industry usage of Class 3 criteria for budget authorization or control estimates.

As can be seen, a substantial majority of projects (84% = 38 of 45) have project total variances that fall within the range of expected outcomes for AACE Class 3 estimates and all but one of the large projects (>$30M) are within this range. Similarly, Figure 2 below shows that nearly all projects (98% = 44 of 45) have schedule variances of less than one year. 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.

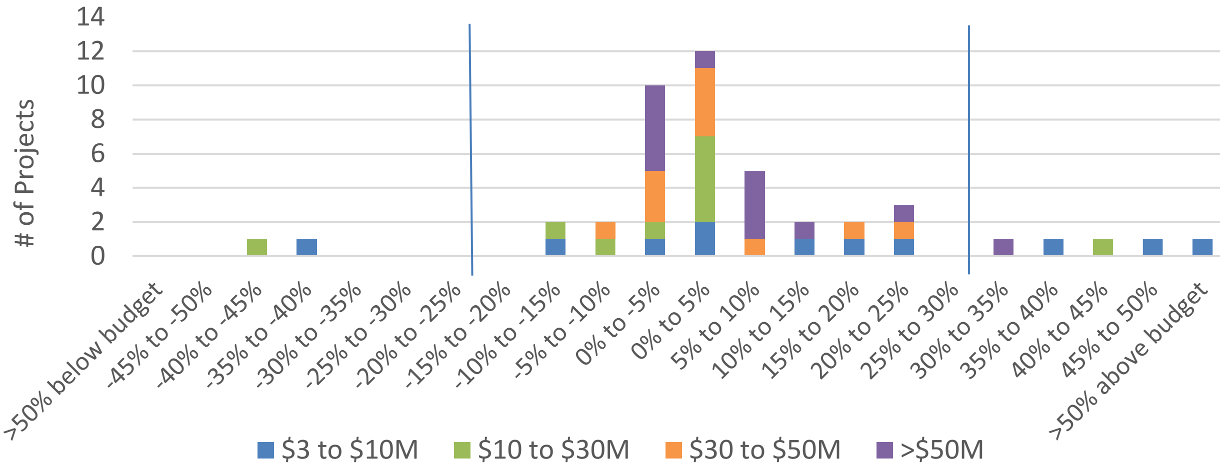

Figure 1: Cost Variance Dispersion for Projects with Planned or Actual ISA in 2020 of $3M or More[5]

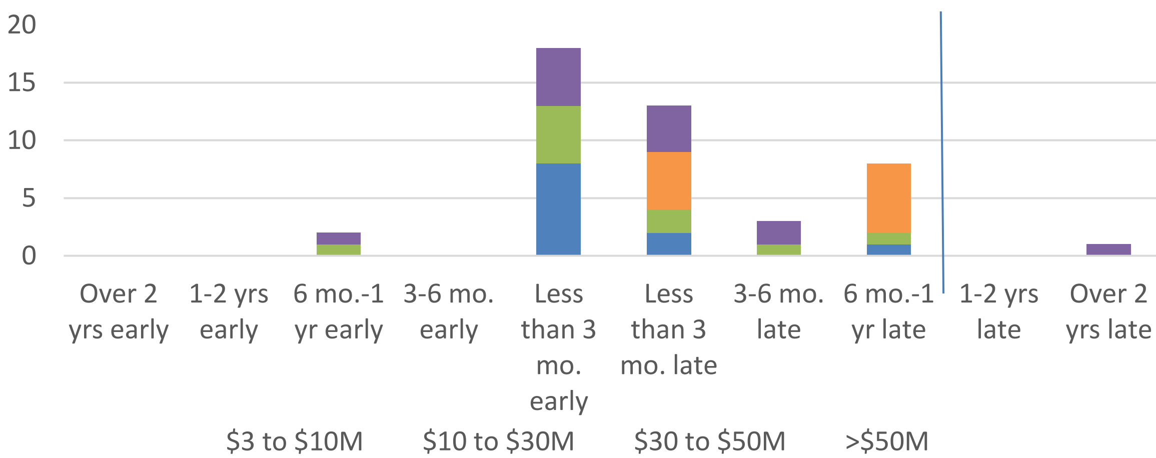

Figure 2: Schedule Variance Dispersion for Projects with Planned or Actual ISA in 2020 of $3M or More[6]

[5] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.
[6] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.

The reasons for variances in individual projects and programs fall mainly into one of 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.

EXECUTION FACTORS

- Execution factors represent changes that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, project plans are adjusted to accommodate the change and mitigate the overall impact to the project cost and schedule. Some of the main causes for such changes are outage delays or cancellations, material delivery and logistics issues, and customer needs.

WORK DEFINITION

- Work definition variances arise as a project’s scope, estimated budget and schedule are refined as the project moves from the high-level planning phase to the detailed execution phase. 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 as the project advances through its lifecycle.

REPRIORITIZATION

- Reprioritization variances include projects that are completed sooner than planned as a result of opportunities that arise during execution or are deferred to later years due to competing priorities. Hydro One’s redirection process, as described in SPF Section 1.7 allows the company to adjust its work delivery when such changes occur.

The tables below provide a summary of all projects and programs with planned or actual in-service additions in 2020 of $3M or more. The suite of projects and programs in these tables represent 94% of the 2020 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. A variance category is provided in the below tables to explain the variance on any project or program that meets the following criteria:

- Projects: project total variance exceeding $0.5M and 10%, or an in-service year shift from 2020 to a future year;
- Programs: 2020 capital expenditure or 2020 in-service addition variance exceeding $0.5M and 10%, or unit variance exceeding 20%.

Table 2 - Project Summary

	Project Phase	ISD Number EB-2019-0082	2020 Capex DRO Plan ($M)	2020 Capex Actual ($M)	2020 ISA DRO Plan ($M)	2020 ISA Actual ($M)	Project Total DRO Plan ($M)	Project Total Actual / Forecast ($M)	Project Total Variance ($M)	In-Service Year DRO Plan	Actual / Forecast In-Service Year	In-Service Year Variance (Years)	Variance Category
System Access													
Load Customer Connection													
Leamington TS: New 230/27.6 kV DESN	**Complete**	Other	2.3	3.6	2.3	3.6	56.9	54.6	-2.3	2018	2018	0	Not a material variance
System Renewal													
Integrated Station Investment													
Birch TS: Component Replacement	**Complete**	Other	1.5	0.8	3.2	2.5	35.6	35.5	-0.1	2020	2020	0	Not a material variance
Chatham SS: Capacitor and Breaker Replacement	**Complete**	Other	0.6	0.6	5.1	5.0	5.1	5.0	-0.1	2020	2020	0	Not a material variance
Chenaux TS EOL Transformer Replacement	**Complete**	Other	5.5	7.4	21.0	22.5	40.2	41.1	0.9	2021	2021	0	Not a material variance
Clarabelle TS: Component Replacement	**Complete**	Other	1.8	1.3	4.2	3.2	6.4	6.6	0.2	2021	2020	-1	Not a material variance
Detweiler TS: T2, T4 & Component Replacement	**Executing**	SR-03	10.5	10.7	11.1	12.5	21.2	22.1	0.9	2021	2021	0	Not a material variance
Dryden TS - ISCR	**Executing**	Other	3.3	0.5	4.0	0.7	38.1	38.1	0.0	2021	2021	0	Not a material variance
Elgin TS; Station Refurbishment	**Executing**	SR-02	8.5	5.2	48.8	44.7	75.1	71.3	-3.8	2021	2021	0	Not a material variance
Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration	**Executing**	SR-02	18.5	18.4	20.0	24.1	53.6	56.8	3.2	2021	2021	0	Not a material variance
Hanmer TS: Northern Station Replacement	**Executing**	SR-02	10.1	20.0	15.5	27.8	83.4	93.5	10.1	2022	2022	0	Execution Factors
Hinchinbrooke SS BULK	**Executing**	Other	0.4	5.2	1.5	4.8	22.5	23.5	1.0	2020	2021	1	Execution Factors

	Project Phase	ISD Number EB-2019-0082	2020 Capex DRO Plan ($M)	2020 Capex Actual ($M)	2020 ISA DRO Plan ($M)	2020 ISA Actual ($M)	Project Total DRO Plan ($M)	Project Total Actual / Forecast ($M)	Project Total Variance ($M)	In-Service Year DRO Plan	Actual / Forecast In-Service Year	In-Service Year Variance (Years)	Variance Category
King Edward TS T3 and PCT Replacement	**Executing**	SR-05	4.8	6.3	4.6	4.0	15.9	15.0	-0.9	2022	2021	-1	Not a material variance
Kleinburg TS: Component Replacement	**Complete**	Other	2.4	1.6	4.9	4.1	5.6	7.0	1.4	2021	2020	-1	Work Definition
Leaside TS BULK; Component Replacement	**Executing**	Other	5.6	5.8	10.8	13.7	57.9	61.2	3.3	2021	2021	0	Not a material variance
Leaside TS: 27.6kV Switchyard & Component Replacement	**Executing**	SR-06	8.4	14.8	25.5	31.9	36.3	45.4	9.1	2020	2021	1	Execution Factors
Manby TS – ISCR	**Executing**	Other	3.7	4.6	3.6	4.3	29.8	31.1	1.3	2021	2021	0	Not a material Variance
Martindale TS: T21/T23 & Component Replacement	**Executing**	SR-02	11.6	9.9	14.0	15.2	73.8	71.8	-2.0	2021	2021	0	Not a material variance
Meaford TS: Component Replacement	**Executing**	Other	4.1	4.3	4.9	5.1	5.3	5.4	0.1	2021	2021	0	Not a material variance
Minden TS: T1, T2, PCT, 44kV Yard & Component Replacement	**Executing**	SR-05	20.8	17.9	25.1	22.0	33.2	34.5	1.3	2021	2021	0	Not a material variance
Newton TS: T1 & Component Replacement	**Executing**	SR-05	3.5	6.6	0.0	5.8	3.5	9.8	6.3	2021	2021	0	Emergent Needs
Runnymede TS: T3, T4 & Switchyard Replacement	**Executing**	SR-02	17.5	17.8	19.8	22.3	30.2	35.9	5.7	2021	2021	0	Execution Factors
Sheppard TS: T3, T4, PCT, LV Yard & Component Replacement	**Executing**	SR-02	20.0	15.6	39.1	33.9	40.2	37.8	-2.4	2021	2021	0	Not a material variance
St. Thomas TS: Station Decom & W3T, W4T, T11T Reconfiguration	**Complete**	Other	1.8	2.2	2.8	3.2	2.7	3.7	1.0	2020	2020	0	Execution Factors
Strachan TS T12/T14; T12 & Component Replacement	**Executing**	SR-05	3.7	5.6	6.0	8.7	13.7	19.4	5.7	2022	2021	-1	Execution Factors
Transmission Station Renewal - Air Blast Circuit Breakers													
Beck 2 TS, ABCB Replacement & Yard Upgrade	**Executing**	SR-01	15.7	11.4	17.1	10.2	132.4	128.4	-4.0	2023	2023	0	Not a material variance

	Project Phase	ISD Number EB-2019-0082	2020 Capex DRO Plan ($M)	2020 Capex Actual ($M)	2020 ISA DRO Plan ($M)	2020 ISA Actual ($M)	Project Total DRO Plan ($M)	Project Total Actual / Forecast ($M)	Project Total Variance ($M)	In-Service Year DRO Plan	Actual / Forecast In-Service Year	In-Service Year Variance (Years)	Variance Category
Bruce A 230kV- Replace Breakers & Upgrade Station	**Complete**	SR-01	6.8	8.5	0.8	12.1	118.6	118.2	-0.4	2021	2020	-1	Not a material variance
Cherrywood TS 230kV BULK; ABCB & Component Replacement	**Executing**	SR-01	20.4	26.7	26.8	31.7	90.3	111.6	21.3	2023	2023	0	Execution Factors
Lennox TS BULK: ABCB Component Replacement	**Executing**	SR-01	13.6	12.5	50.0	58.8	108.6	142.5	33.9	2024	2026	2	Work Definition
Middleport TS ABCB Replacement	**Executing**	SR-01	19.6	35.3	21.0	19.6	113.4	119.8	6.4	2025	2025	0	Not a material variance
Nanticoke TS ABCB Replacement	**Executing**	SR-01	10.1	16.7	0.0	11.4	61.2	66.5	5.3	2025	2025	0	Not a material variance
IT Security													
ISL Replacement-Discovery-Capital	**Executing**	SR-29	4.4	4.3	6.2	6.1	11.8	12.2	0.4	2021	2021	0	Not a material variance
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects													
D6V/D7V, Guelph North JCT-Fergus TS, Transmission Line Refurbishment	**Complete**	Other	4.4	4.4	6.5	3.6	12.4	7.0	-5.4	2021	2020	-1	Work Definition
CxA, Cameron Falls GS-Alexander G	**Executing**	Other	1.2	1.3	7.5	6.7	7.5	8.5	1.0	2020	2021	1	Execution Factors
D3A, Allanburg TS X ASW Steel CT	**Complete**	SR-19	-0.8	2.8	12.1	12.6	12.9	13.5	0.6	2020	2020	0	Not a material variance
D4Z, Nine Mile JCT-IPB Casey JCT	**Complete**	Other	2.4	3.6	4.4	4.5	3.4	4.0	0.6	2021	2020	-1	Execution Factors
Transmission Line Refurbishment													
A7L/R1LB/A6P & 57M1, Alxdr B-Lkhd, Transmission Line Refurbishment	**Executing**	SR-19	24.9	15.0	0.0	6.0	67.9	68.3	0.4	2022	2022	0	Not a material variance
B3/B4, Horning Mt. - Glanford, Transmission Line Refurbishment	**Complete**	SR-19	7.2	6.8	15.2	12.4	19.4	17.3	-2.1	2021	2020	-1	Execution Factors
D6, Des Joachims TS X Petawawa DS, Transmission Line Refurbishment	**Executing**	SR-19	4.4	16.1	2.2	12.7	41.3	42.5	1.2	2021	2022	1	Not a material Variance

	Project Phase	ISD Number EB-2019-0082	2020 Capex DRO Plan ($M)	2020 Capex Actual ($M)	2020 ISA DRO Plan ($M)	2020 ISA Actual ($M)	Project Total DRO Plan ($M)	Project Total Actual / Forecast ($M)	Project Total Variance ($M)	In-Service Year DRO Plan	Actual / Forecast In-Service Year	In-Service Year Variance (Years)	Variance Category
Protection and Automation													
Install DDRs for NERC Compliance	**Executing**	Other	4.4	3.6	4.0	3.8	9.3	8.3	-1.0	2022	2021	-1	Work Definition
Underground Lines Cable Refurbishment & Replacement													
HV UG Cable - Replace H7L/H11L	**Complete**	Other	3.9	4.4	40.9	41.3	43.0	45.4	2.4	2020	2020	0	Not a material variance
System Service													
Inter Area Network Capability													
Lennox TS 500kV Shunt Reactors	**Executing**	SS-01	18.9	21.8	22.0	0.0	46.2	47.2	1.0	2021	2021	0	Not a material variance
Local Area Supply Adequacy													
Hawthorne TS: Replace 2 Existing Transformers	**Executing**	Other	4.7	2.4	10.3	0.1	20.9	20.4	-0.5	2021	2021	0	Not a material variance
Kapuskasing Area Reinforcement	**Executing**	SS-10	15.2	16.6	11.2	11.9	33.7	32.0	-1.7	2022	2022	0	Not a material variance
Performance Enhancement													
Port Colborne TS - Outlier Performance Improvement	**Complete**	Other	2.3	3.2	2.9	3.9	6.2	3.9	-2.3	2020	2020	0	Work Definition
Risk Mitigation													
L7S - Reliability Performance Mitigation	**Complete**	Other	2.1	3.7	0.0	4.3	3.6	5.3	1.7	2021	2020	-1	Work Definition
Grand Total			**356.7**	**407.8**	**558.9**	**599.3**	**1750.2**	**1848.9**	**98.7**				

1 **Table 3 - Program Summary**

	ISD Number	2020 Capex DRO Plan ($M)	2020 Capex Actual ($M)	Capex Variance ($M)	2020 ISA DRO Plan ($M)	2020 ISA Actual ($M)	ISA Variance ($M)	Reportable Unit	2020 Unit DRO Plan	2020 Unit Actual	Unit Variance	Variance Category
System Renewal												
Overhead Lines Component Replacement Programs and Secondary Land Use Projects												
Steel Structure Coating Program	SR-22	9.3	8.1	-1.2	12.0	10.6	-1.4	# of structures	222	222	0	Work Definition
Transmission Line Emergency Restoration	SR-26	9.7	12.0	2.3	8.8	12.5	3.7	# of work orders	108	166	58	Emergent Needs
Transmission Line Insulator Replacement	SR-25	58.8	57.1	-1.7	62.9	58.2	-4.7	# of circuit structures	3179	2794	-385	Not a material variance
Transmission Line Shieldwire Replacement	SR-24	10.7	4.3	-6.4	10.8	2.7	-8.1	# of km	282	39	-243	Execution Factors
Wood Pole Structure Replacements	SR-21	45.3	47.0	1.7	45.9	44.9	-1.0	# of structures	897	796	-101	Not a material variance
Tower Foundation Assess/Clean/Coat & Life Extension Program	SR-23	10.6	9.5	-1.1	12.5	9.0	-3.5	# of structures	1177	1060	-117	Reprioritization
Tx Transformers Demand and Spares												
Online DGA Monitor Program	Other	1.4	1.6	0.2	3.0	2.2	-0.8	# of units	3	2	-1	Execution Factors
Transmission Station Demand, Spares and Targeted Assets	SR-09	54.7	59.1	4.4	65.7	60.9	-4.8	Various	-	-	-	Not a material variance
IT Security												
NERC CIP-014 Physical Security Upgrades	SR-16	18.0	24.2	6.2	21.3	7.9	-13.4	# of sites	11	2	-9	Execution Factors
Grand Total		**218.5**	**222.9**	**4.4**	**242.9**	**208.9**	**-34.0**					

As evidenced in Table 2 above, the majority of projects do not show a material variance with respect to the overall project total budget or project schedule. This further emphasizes that projects are well managed with a focus on adherence to the overall project total budget and project schedule. In terms of exceptions, the Hanmer TS: Northern Station Replacement Project is forecasting to exceed its total budget by $10.1M as a result of multiple execution factors including outage cancellations, failures on existing equipment, and scope additions. The Lennox TS Bulk: ABCB Component Replacement Project is forecasting to exceed its total budget by $33.9M as a result of work definition issues that resulted in scope evolution and additions subsequent to the project's funding approval, as well as, a reprioritization of resources for customer driven work. Finally, the Cherrywood TS 230 kV Bulk: ABCB and Component Replacement project is forecasting to exceed its total budget by $21.3M due to multiple execution factors including complexity of replacing the station service systems, setup of site facilities, overruns on two buildings, relocation of fiber cables, and scope additions.

Table 3 above shows program performance in relation to annual budgets. The three largest program areas, 1) Transmission Line Insulator Replacement, 2) Wood Pole Structure Replacement, and 3) Transmission Station Demand, Spares and Targeted Assets do not have any material variance with respect to their annual budgets which demonstrates that they are effectively managed.

In terms of spending, Table 3 shows that the two largest program variances, in both percentage and absolute dollar terms, are Transmission Line Shieldwire Replacement and NERC CIP-014 Physical Security Upgrades. Transmission Line Shieldwire Replacement experienced multiple execution issues stemming from outage delays, the need to replace wood poles on certain circuits before replacing the shieldwire, and delays to allow additional time for Indigenous consultation and engagement. NERC CIP-014 Physical Security Upgrades experienced execution issues due to resourcing constraints which resulted in only partial completion at various sites and led to reduced overall accomplishment. Work on this program is a high priority for 2021, with dedicated resources devoted to it, to ensure NERC requirements are met before the end of 2022.

4.0 CONCLUSION

This Capital Program Performance Report intended to highlight Hydro One's 2020 performance through the following three lenses:

- Adherence to the overall capital envelopes for the year
- Project performance in relation to approved project execution budgets
- Program performance in relation to annual budgets

At an envelope level, Hydro One performed well both in terms of capital expenditure and in-service additions in 2020 with minimal variances to the overall capital envelope. Project performance in relation to project total budgets was also very good with 84% of projects having total cost variances within the range of expected outcomes for AACE Class 3 estimates, and 98% of projects having a schedule variance of less than one year. Program performance in relation to annual budgets was also good as the three largest program areas did not have material variances against their annual budgets. In addition, as discussed in TSP Section 2.10, Hydro One is working to continuously improve its delivery of its capital program. Overall, this report demonstrates Hydro One's effective capital portfolio management practices and ability to deliver its capital program.

SECTION 2.10 - TSP - CAPITAL WORK EXECUTION

2.10.1 INTRODUCTION

This section explains how Hydro One executes its large and complex portfolio of capital work on the stations, lines and equipment that comprise the transmission system. The planning and prioritization of capital work is determined through the Investment Planning process discussed in Section 1.7 of the System Plan Framework (SPF). The focus here is on how Hydro One executes the planned investments through programs and, primarily, through 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 result derives from a mature capital delivery process with strong oversight and governance and an experienced execution organization that completes the work using both Hydro One's skilled internal workforce and qualified external contractors. The capital delivery process is well understood and followed, scalable to accommodate the necessary growth in capital work, optimized to reflect the Hydro One work program and execution strategy, and includes a continuous improvement model to ensure that it is driving best practices. Hydro One's capital project execution has been independently reviewed by UMS Group (see TSP Section 2.3, Attachment 1), which concluded that overall Hydro One has a mature project delivery process that performs well relative to industry peers.

Hydro One's work planning and execution activities focus on the company's business objectives including safety, quality, efficiency, and meeting customer commitments. As a result, Hydro One takes an efficient, adaptable approach to its capital work program, which gives it flexibility to accommodate new circumstances that may arise over the course of a multi-year project such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities, and emergent investments.

2.10.2 CAPITAL DELIVERY PROCESS

As noted above, the capital delivery process starts with the planning and prioritization of capital work through Hydro One's Asset Management and Investment Planning Process (see SPF Section 1.7). As discussed there, capital work is planned to address asset condition and anticipated system needs using a risk based approach. The product of the planning process is a series of investment needs that are met through the development of capital programs and projects.

Programs and projects are the vehicles by which Hydro One's capital work program is planned and delivered. A program is defined as a specific body of work where the type of work is repetitive, recurs year over year and alternative approaches do not exist to achieve the objective. An example of a Program is Pole Replacements. A project is defined as a specific undertaking at a particular location that occurs during a specific time period. This period may cover more than one fiscal year. 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. An example of a Project would be refurbishment of a Transmission Station.

2.10.2.1 PROGRAM DELIVERY MODEL

Approximately 20% of the capital portfolio is planned and executed using a programmatic methodology with a focus on like-for-like asset replacement on transmission lines (e.g., insulators, wood poles, tower coating, etc.) and unplanned replacements for both stations and lines assets. The planning of a program is less involved than that of a project based on the difference in risk exposure between the two.

The process for programs has three phases: Planning, Program Development and Execution. Planning involves the identification of the scope of work through the planning and prioritization process identified in SPF Section 1.7 and estimated using average unit prices. The work is released on an annual basis after the approval of the Hydro One Business Plan approval.

Visibility to future years (usually two additional years) scope of work is provided to the executing lines of business to allow them the flexibility to gain efficiencies by bundling work or bringing work forward if an execution challenge (e.g., a cancelled outage, resource conflict or permit issue) is encountered.

During the Program Development Phase, the Work Management Team, comprised of program managers, works with the executing lines of business to plan the outages, resources, material and equipment to safely and efficiently deliver on the work program. It also works collaboratively with several other functional areas to plan the work safely and efficiently. For example, the Environmental Services team is engaged 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.

In the Execution Phase, work moves through the various sub-phases that take the project from engineering through to commissioning as discussed below. Transmission capital work is executed by three functional workgroups, Stations Construction, Stations Services and Transmission Lines, which are described below in Section 2.10.4.1.

2.10.2.2 PROJECT DELIVERY PROCESS

Once the Investment Planning Process has determined what investments are required, as mentioned above and discussed in SPF Section 1.7, Hydro One's project delivery process, illustrated in Figure 1 below, is used to develop and execute the projects necessary to meet the Investment Plan. The project delivery process comprises three key phases: (i) Planning; (ii) Project Definition, which includes the Project Scoping and Project Planning sub-phases; and (iii) Execution, which includes Project Execution and Project Close sub-phases. Each of these phases and sub-phases are discussed in the sections that follow. At the completion of each phase, all projects with an expected project total greater than $7M[1] go through a Stage Gate Review to

[1] This aligns with the Vice President approval level.

challenge the results of the completed stage and determine whether it is ready to progress to the next stage.

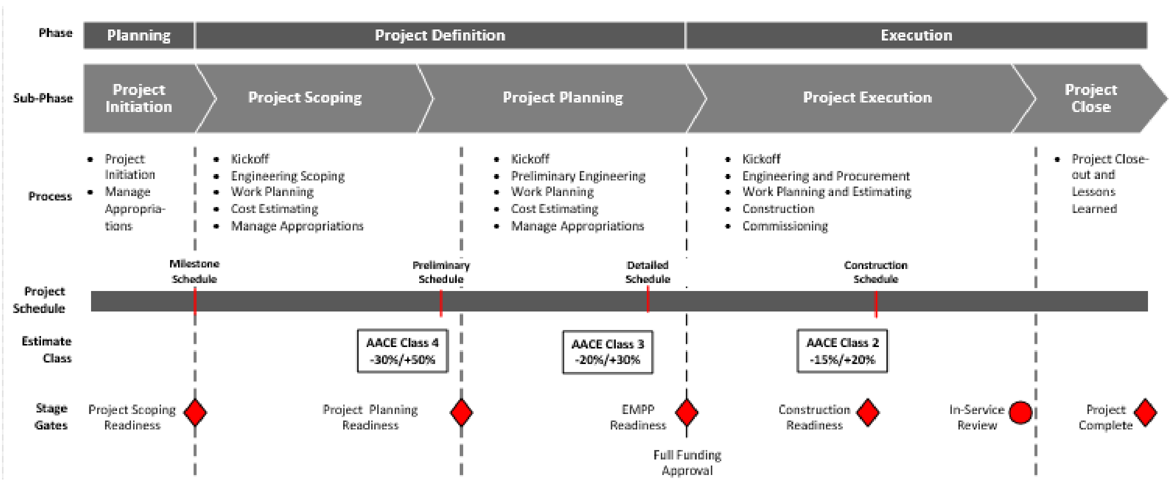

Figure 1: Transmission Capital Project Delivery Model

Stage Gate Reviews are held to evaluate a project's progress against plan and to determine whether a project should proceed or not. The review is conducted by the Transmission and Stations Vice-President, and includes participation from Directors across the organization who are responsible for sub-elements of the plan (e.g. Planning, Engineering, Project Controls, etc.). For larger projects, Hydro One defines five stage gate approvals for each project: one in Project Planning, two in Project Definition, one in Project Execution and one at Project Close.[2] Projects pass through stage gates before moving into the next sub-phase in the capital delivery process as shown in Figure 1 above. The stage gate review process provides senior management with visibility into current project performance, risks and issues allowing for proactive adjustments in project execution plans as required.

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[2] As discussed in Section 2.10.6, smaller projects go through a simplified process.

Each project has a project execution plan that is refined throughout the process comprised of scope, schedule and cost elements. As the scope, design and execution are further defined throughout the process, cost and schedule accuracy improves.

Hydro One continues to refine its capital delivery process, primarily in the Project Definition phase. These efforts, which are designed to improve execution efficiency, are described in section 2.10.6 below.

2.10.2.3 THE PLANNING PHASE

In the Planning Phase, Hydro One takes the needs identified in the Investment Planning Process and develops them into projects with high-level project scopes. The Planning Phase evaluates the resource requirements and determine the delivery model of the work in the investment plan. This includes clarifying assumptions and identifying interim milestones for the subsequent Project Definition Phase so the company can monitor progress and identify challenges early in the process. As a result of this work, a high-level planning allowance and project summary schedule are identified using comparator projects and execution expertise.

2.10.2.4 PROJECT DEFINITION PHASE

Project Definition consists of two sub-phases: Project Scoping and Project Planning as further described below. Project Definition is led by project managers and accomplished using cross-functional teams. These teams include Hydro One professionals from engineering, project controls, real estate, environmental approvals and compliance, construction services, system operations, supply chain, and maintenance workgroups, as well as lines of business representing customers, communities (including First Nations and Métis communities) and external agencies.

In the Project Scoping and Project Planning sub-phases (discussed in the sections that follow), 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 registers and basis of estimate). Because only a small percentage of the project engineering has been completed in these sub-phases, the cost estimates are based on typical costs for common elements based largely on past experience. As work in the Project Definition phase progresses and the specific requirements of the project are developed, estimate accuracy increases and potential variability decreases.

2.10.2.4.1 PROJECT SCOPING

The objective of Project Scoping is to produce a final scope of work, which includes an initial cost estimate and schedule.

The project manager 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 or 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 Project Planning sub-phase. There is a standard set of planning criteria that is used to measure the projects’ readiness to proceed. These 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 stage of the project delivery process, sufficient cost-based estimates and available site specific information has been developed to prepare an AACE Class 4 estimate, which has an accuracy range of minus 30% to plus 50% (see Section 2.10.2.6.2 for more on the AACE Estimating process). This range is appropriate as the project definition deliverables are in the order of 15% complete at the conclusion of project scoping. 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.

2.10.2.4.2 PROJECT PLANNING

In Project Planning, Hydro One prepares a project execution plan that captures the scope, schedule and cost requirements and identifies risks that have the potential to change the project scope, schedule or cost. During this phase Hydro One may conduct preliminary stakeholder and Indigenous Community engagements. Engagements with Indigenous Communities are becoming more complex and taking longer to complete, and are subject to increased scrutiny during the environmental assessment process.

The project execution plan includes the following items, as referenced in the capital delivery process diagram at Figure 1:

1. Engineering package: At the conclusion of this phase, all major material and engineering studies and surveys are complete and basic layout drawings and phasing of the work are determined;
2. 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);
3. 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 $10M, which identifies potential likelihood and consequences of project risks (see Section 2.10.2.6.2 for more information on the risk definition and management). The output of the risk workshop informs the project contingency amount; and

4. 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.

This package of materials is reviewed by the project manager in preparation for the Project Execution Readiness stage gate.

Between the Project Planning and Execution phases, the final plan is reviewed and approved by the appropriate expenditure authority[3] via a business case summary. Upon approval, the project is expected to be executed per the scope, cost and timeline set out in the project plan, within the estimate accuracy range (as described in the paragraph below).

An AACE Class 3 estimate with an accuracy range of minus 20% to plus 30% is prepared using information provided in the engineering deliverables and project execution plan. The maturity level of deliverables in the project definition phase is in the order of 25% complete for stations projects and up to 75% complete for lines projects.

2.10.2.5 EXECUTION PHASE

In the Execution Phase, work moves through the Project Execution and Project Close sub-phases. Project Execution contains three steps: (i) detailed engineering and procurement; (ii) construction; and (iii) commissioning, as set out in Figure 1 above and described below. Transmission capital work is executed by three functional workgroups, Stations Construction, Stations Services and Transmission Lines, which are described at the end of this section.

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[33] The appropriate expenditure authority is defined by the Expenditure Authority Register, which establishes the spending and investment limits associated with each organizational level from Board of Directors to the CEO and through levels of management.

2.10.2.5.1 PROJECT EXECUTION - 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. Once most of the production engineering work is complete, a significant component of variability is removed from the project and it is reasonable to expect that the cost, planned accomplishments, and schedule milestones will be met within the specified tolerance, barring extraordinary circumstances.

2.10.2.5.2 PROJECT EXECUTION - CONSTRUCTION

Hydro One reviews its ready for construction engineering packages, updates plans and verifies costs before moving into construction. These steps are taken to minimize errors and changes, both of which can increase cost and cause delay.

In Project Execution, the project is built to the required technical standards and detailed engineering specifications. The project manager is responsible for coordination of all workgroups contributing to deliver the work plan on time and in a manner that is safe and cost effective. The project manager:

- 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 section 2.10.3.1.

Detailed job planning and regular onsite planning meetings are used as key communication tools during the process. These tools are used throughout construction from site preparation and civil/electrical work to major equipment installation and site remediation activities to ensure the safe execution of planned work.

2.10.2.5.3 PROJECT EXECUTION - COMMISSIONING

When construction is complete, the project is passed to the Stations Services and Operating divisions for formal site acceptance testing and commissioning. Upon completion of these steps, the asset is transferred to the System Operations Division for on-going control and operating. This process ensures quality, safety, efficiency and readiness of the new assets.

2.10.2.5.4 PROJECT CLOSURE

The project closure process was introduced as a new stage gate in 2018 to ensure 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 capital projects with a budget of $5M or greater to review project objectives, ensure they have been met and to discuss ‘lessons learned’. The project closure process engages key individuals who participated in the capital work program lifecycle to ensure knowledge transfer for future projects and to reinforce a culture of continuous improvement.

2.10.2.6 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 process.

2.10.2.6.1 PROJECT MANAGEMENT

Project Delivery Managers (PM) are accountable for a project from the beginning of the Project Scoping phase through to project close. 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 and reporting on the project during both the project definition and execution phases and require a broad set of skills including: leadership, communication, coordination, cost control, schedule management, risk management, and critical thinking. The PM is the single point of contact on a project and is critical to its success. 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 and managing any necessary changes.

2.10.2.6.2 PROJECT CONTROLS

Estimating: As mentioned above, Hydro One utilizes the AACE Classification Scheme which is an industry-established estimating classification scheme intended to appropriately communicate and set expectations for estimate accuracy by project phase based upon the maturity of underlying deliverables associated with planning/engineering/construction work that has been completed.

Scheduling: Hydro One utilizes Primavera P6 (P6) as a project scheduling tool and to create standardized project schedule reports in both the Definition and Execution phases. The use of P6 improves communication of schedule information throughout the capital delivery process.

In the Definition Phase, Hydro One uses P6 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 rapidly monitoring project and portfolio performance.

Change Management Process: Hydro One continues to enhance its cost control and change management processes. The improved change management process allows project teams to better track costs, forecast and communicate variances in resourcing and cash flow both during a project and at project close. Improvements include a new simplified and standardized work breakdown structure, which was used to create a cost controller role in SAP that generates cost control reporting utilizing the new work breakdown structure. The project manager is now supported by cost controllers and cost reports are generated with the new work breakdown structure to assist with project forecasting and reporting variances.

Risk Definition and Management Program: Hydro One has a robust risk definition and management program that is applied to all projects with a gross total estimated cost of more than $10M. This risk program reviews scopes, execution plans and schedules to identify potential likelihood and consequence of project risks materializing. This information is used to quantitatively analyze risk and develop project contingency using a predictive modeling and optimization tool. Project risk mitigation plans are also developed at this stage.

Each project is subject to a risk review meeting to develop the project-specific risk registry. The risk review meeting includes Hydro One representatives from across the organization to provide full representation of different corporate responsibilities. Early, integrated review and mitigation planning allows greater control of project variances by anticipating issues and planning for the responses (actions and funding). For smaller projects, a risk registry is created, but a formal workshop and predictive modeling are not required.

2.10.3 PROJECT OVERSIGHT

The capital delivery process described in the previous section establishes the planning, definition and execution of individual projects. The material that follows in this section presents Hydro One’s approach to managing the overall portfolio of capital work, tracking work accomplishment 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 overall capital work plan.

2.10.3.1 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.

Reporting on Project and Program Status: Hydro One reviews its project and program status on a monthly basis. 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 that have significant in-year capital expenditures or in-service additions are reviewed from an execution perspective. Hydro One uses a combination of standard reporting requirements, key performance indicators, and a change management approval processes, both 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 changes, 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 monitoring any changes in the average unit process throughout the year and against previous year's performance.

Contingency Reviews: Hydro One regularly reviews the amount of contingency held within each portfolio along with future year capital expenditures and in-service addition assumptions. The review considers the project and the associated risk to determine appropriate contingency amount to hold in the portfolio.

Portfolio Management: At the portfolio level, Hydro One reviews its capital budget and in-service additions on a two-year rolling basis. As an input to this review, project managers provide a multi-year forecast for all work in execution and for work that is in project planning where an estimate has been completed. The goal of the review is to establish a comprehensive view of the project landscape, ensure that planned work is being completed and that adequate work is planned and available for future execution.

For projects in the execution stage, Hydro One reviews in-service additions on a multi-year basis. This allows the company greater flexibility to plan and reschedule projects within a two-year rolling window. It also provides sufficient notice should changes in project execution priority be required. Project managers forecast multi-year in-service additions and report partial in-servicing to optimize portfolio management and reduce interest costs for assets under construction. Forecasting multi-year in-service additions and reporting partial in-servicing also allows Hydro One to anticipate and track the impact of in-year changes on future years.

2.10.3.2 GOVERNANCE

Stage Gate Approvals: As discussed above (see Section 2.10.2.2), Stage Gate Approvals provide ongoing visibility into individual project performance, risks and issues, and are an important input into the project portfolio review and governance process.

Executive Review On a monthly basis the capital work program is reviewed through a series of meetings starting at the Director level and rolling up through the Vice-President and Chief Operating Officer and ultimately to the Executive Leadership team. The portfolio is analyzed through a number of different metrics including in month performance, year to date performance and year-end forecast against a trended budget. The portfolio is also reviewed through a project lens comparing project financials and schedules to the project budget and plan.

Redirection: As discussed in SPF Section 1.7, redirection refers to the process by which changes are made to the investments included in Hydro One's business plan. Within capital work execution, approved projects may be advanced or delayed to address emergent issues or factors that require the postponement of a project such as equipment or outage availability.

2.10.4 FACTORS IMPACTING WORK EXECUTION

2.10.4.1 EXECUTION RESOURCES AND APPROACH

Hydro One will employ a range of resources to execute the capital portfolio over the test period. These include: internal resources, the direct-hire 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.

Hydro One has three internal workgroups that are accountable for executing its transmission capital work program:

- 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 30,000 kilometers of Transmission Lines. This work is executed by the PWU and Construction Trades Unions.
- Stations 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 SUP unionized employees.

Direct hire construction trades and the PWU workforce will continue to execute the majority of the capital work program to ensure that Hydro One remains a knowledgeable owner, and efficiently manages risk when working on brownfield refurbishments which are typical of the System Renewal category. The growing capital program will require increasing the FTEs within the casual workforce. Planning assumptions foresee modest increases in the usage of PWU Hiring Hall staff to support the increase in the growing work program, and outsourcing a greater portion of the total volume of work to accommodate the investment plan. Despite growth in planned work, the management segment of this workforce will remain static throughout the rate period, and only minor increases to the regular workforce (PWU and Society), will be required to meet these growing demands.

Overtime levels are expected to be similar to those in previous years largely due to the demand nature of a portion of the work program. Overtime it typically required to address imminent component failures and prioritized repairs to ensure assets are placed back in operational condition to avoid or address outages. Demand Overtime also refers to overtime necessary to contend with shortened outages and rescheduled cancelled outages due to system operating conditions.

Overtime usage is also required to perform outage work that is time-constrained, and may need to be done during a customer outage, (i.e., 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 the flexibility to accommodate these constraints.

Within Transmission, overtime hours account for approximately 8% of all hours worked (for variable staff), and the current planning assumptions rely on this historic ratio. The usage and planning assumptions for overtime are heavily scrutinized. Initiatives through the Continuous Improvement Model to ensure overtime utilization is dedicated to projects and demand work were implemented in previous years within Stations Services and are already reflected in the current overtime level.

The Transmission Lines and Stations groups perform monthly reviews to monitor the use of overtime. Opportunities for optimizing overtime are reviewed and pursued where appropriate. As an example, Transmission Lines created two travelling crews out of Sault St. Marie and Timmins to reduce significant travels times. Before this change, employees traveling from Sudbury could incur significant travel time to certain outage locations, which led to additional overtime. This change reduced the overtime by approximately 20% in this location over the course of a year. In addition at the local levels, Superintendents pre-approve overtime prior to utilization to ensure it is prudent and required.

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 onboarding, training, supervising, and directing) additional employees to perform the same volume of work over a longer period of time. 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 actually hamper efficiency. Finally, for projects that require significant set-up and take-down, using overtime to complete the job in one day rather than completing it over two days of regular time can reduce costs.

Hydro One's execution strategy over the test period includes leveraging external delivery partners to complement existing internal teams and provide operational flexibility to meet the growing capital work program. Demand for load growth investments is increasing and timelines to respond are shrinking. 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 including by involving them early in the development projects 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 Engineer, Procure, Construct (EPC) services for select projects; specialty construction skills that are not retained within Hydro One (i.e. tunnelling, high voltage cable installation); and specialty equipment rentals with operators (e.g. 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 (RFP) process to select the best service provider for particular work assignments. 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 flexibility and ability to ramp up quickly to respond to a growing work program and deliver on strategic priorities. Hydro One plans to utilize its skilled resources to execute 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, air blast circuit breaker replacement projects, customer connections, like-for-like program replacements and some transmission line refurbishment projects.

Hydro One uses external delivery partners to scale up and respond to needs for new transmission line and station projects where the scope can be clearly delineated, risk and complexities are low and measurable deliverables and milestones can be clearly articulated. In addition, high voltage cable projects and tunnelling activities, where Hydro One does not retain the skillset internally due to the infrequent nature of the work, are externally delivered.

2.10.5 SAFETY

Hydro One is committed to become the safest and most efficient utility through initiatives that drive operational performance in alignment with our values, vision and mission. As shown in Figure 2, these initiatives have resulted in a steady decrease in the Station Services, Stations Construction and Transmissions Lines recordable injury frequency rate, despite the substantial growth in the work program over the years. The occurrence of significant incidents classified as High Maximum Reasonable Potential for Harm (HMRPH) events have also decreased over recent years.

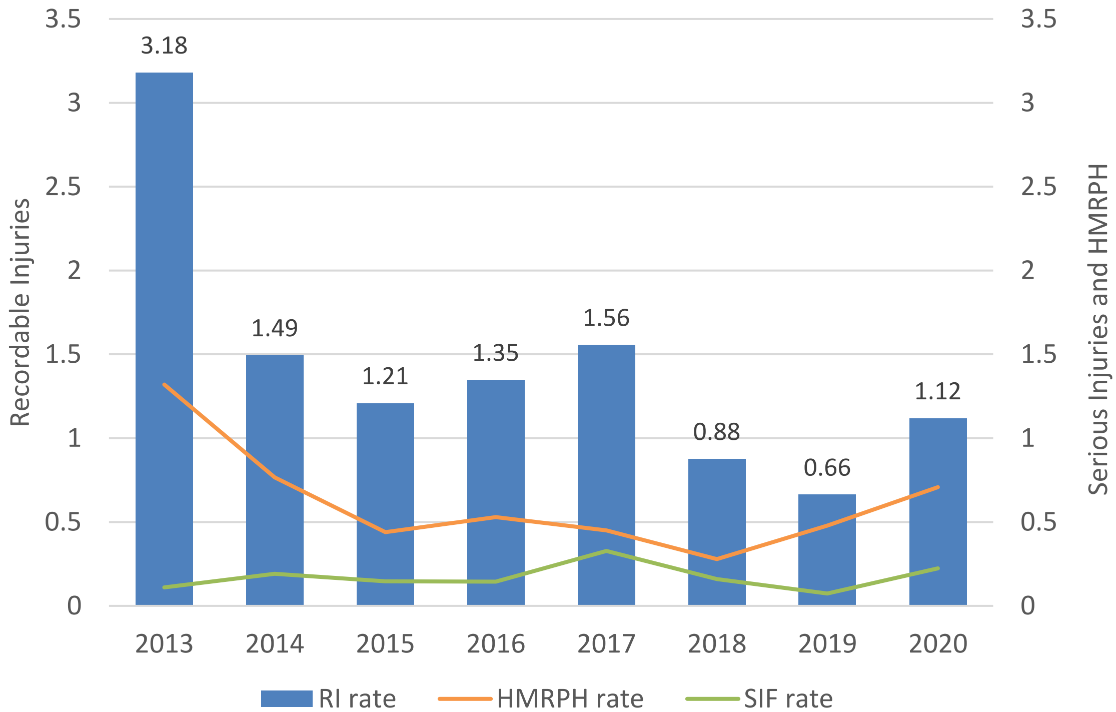

Figure 2: Frequency per 200,000 Hours Worked (Transmission and Stations)

Hydro One believes that being a safe utility is a necessary element of being an efficient utility, and that a healthy safety culture fosters accountability and discipline across all aspects of our business. A Chief Safety Officer (CSO) role was established in 2020 to lead the transformation of the safety culture, and the HSE function was recently redesigned to provide a more effective focus on our health and safety management systems, training and development, operations field support and learning, analytics and reporting. Furthermore, a Safety Improvement Team was created from a diverse cross section of the organization to identify areas of improvement to help prevent serious injuries and fatalities.

Hydro One is striving to transform and improve our safety culture through robust safety analytics and grass-roots employee engagement. The Safety Improvement Team has connected with more than 4,200 workers across the company, completed an analysis of Hydro One's historical performance, and gathered safety best practices from external companies. From this research, the team has outlined a plan to eliminate serious injuries and fatalities by 2024. This will be accomplished by addressing the root causes of our safety issues, transforming our culture, and by embedding the right values, mindsets and behaviours.

In a healthy safety culture, there is a high-degree of accountability and engagement across every level of the organization. Hydro One employees reported just over 5,800 Near Misses and Safety Catches in 2020, which exceeded the annual target of 4,000. Going from 57 reported near misses in 2018 to 5,800 in 2020 demonstrates employee buy-in and successful adoption of the new mobile reporting tool, which work together to help establish a positive learning organization. The next phase will be to incorporate analytics and an ongoing feedback mechanism to drive continuous improvement.

Hydro One continues to improve workplace health and safety culture and performance through an integrated set of managed systems. These systems are structured to ensure the frontline workers and supervisors are well informed of potential risks, and are actively engaged in hazard identification and safe work planning. Communication tools such as weekly safety bulletins are distributed and shared with staff at the Monday morning tailboard sessions to share relevant safety updates. Onsite planning meetings are carried out at the start of each day and after breaks to refocus staff and reinforce safe work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone's viewpoints are heard. Crews also participate in warm-up/stretch sessions during the course of the day as needed to reduce the occurrence of soft tissue injuries.

Hydro One continues to deliver safety roll-outs to the field crews to reinforce the leadership's commitment to safety and to ensure roles and responsibilities are communicated consistently. Safety roll-outs communicate the results from ongoing near miss / safety catch reporting and emphasize the importance of job planning in incident prevention and operations efficiency. Workplace Safety Observations are also being carried out by managers and supervisors to ensure visible safety leadership presence in the field and 2-way communication through coaching and feedback. In 2020, over 5,300 Workplace Safety Observations were carried out.

The company is continuing to evolve the Human Success program, elsewhere typically referred to Human Performance, taking a managed systems approach to identification and mitigation of error-likely situations. Advancement in these areas has led to improvement not only to safety, but also to overall efficiency, quality of work, and reliability.

2.10.6 PRODUCTIVITY AND CONTINUOUS IMPROVEMENTS

2.10.6.1 PRODUCTIVITY

Hydro One continues to seek opportunities to improve process efficiencies that result in cost savings in the execution of its work programs as outlined in SPF Section 1.4 - Productivity Framework.

Hydro One has recently undertaken a number of initiatives to increase the effectiveness and efficiency of its capital work program delivery. These initiatives are described in the following sections.

2.10.6.2 TRANSMISSION CAPITAL DELIVERY MODEL ENHANCEMENT INITIATIVE

In 2020, Hydro One initiated an initiative to enhance the Transmission Capital Delivery Model. The goal was to clarify decision authorities, strengthen the authority of project managers operating in a matrix organization, and improve the predictability of project success. This initiative is expected to be completed in 2021 and will:

- Increase efficiency in end-to-end project duration, by enhancing accountabilities and further clarifying and empowering efficient decision making authority throughout the project;
- Reduce schedule variances by improving the tracking and reporting of project commitments made in the Project Planning phase;
- Enable greater visibility of project changes and improve the management of project funds; and
- Enable greater oversight and insights of the Project Delivery Model (PDM), which will lead to continuous improvement and enhanced enterprise efficiency.

One of the ways Hydro One is planning to reduce schedule variance is to enhance the PM's ability to hold project groups accountable and highlight the importance of accurate project commitments in the Project Planning and Execution phases. This initiative will introduce Work Package Agreements, which are documented agreements between Lines-of-Business (LoBs) and PMs. The work-package outlines and establishes accountability to the commitments made by respective LoBs during the Project Planning phase. Use of these agreements will establish accountability to the PM through defined formal commitments to the project timeline and milestones; and reinforce and document LoB accountability to the PM. Use of Work Package Agreements will result in alignment across the project team on key milestones and cost commitments for success and assist the PM in more effectively managing project priorities and timelines.

To enable greater visibility into project changes and improve the management of project funds Hydro One will improve its change management process through:

- The consistent identification and documentation of project changes through the use of clear, uniform terminology and improved data capture for lessons learned and portfolio analytics;
- Enhancing the governance of how changes within a project are funded to better align with the Expenditure Authority Register; and
- Clearly defined responsibilities for work facing individuals (Control Account Managers) to manage work within their assigned budget.

Hydro One is developing a continuous improvement framework to improve consistency and alignment with Project Management best practices. A new role entitled Practice Lead was created to own and maintain the PDM model. The new role is accountable to continuously improve the application of the PDM across the organization and keep abreast of PDM process developments by staying current with industry best practices. Specifically the Practice Leads will provide regular communication and training to staff, and ensure process adherence.

The full PDM is used for major transmission capital projects, but applying it to all projects is not feasible given the cost and time required. As a result, Hydro One plans to develop predefined, tailored paths through the PDM for those projects in the investment plan that do not warrant the full PDM. The paths will determine the appropriate combination of inputs, tools, techniques, and outputs to effectively deliver the project. The goal is to define an appropriate ranking system based on project cost and complexity 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 a simplified approach for projects that do not require the full PDM**.** This process will optimize the resourcing requirements across the portfolio to focus on the higher ranked (i.e., more impactful) projects, and will result in a shortened timeframe to complete review of the lower ranked projects.

2.10.6.3 CONTINUOUS IMPROVEMENT MODEL – FIELD PRODUCTIVITY INITIATIVE

In 2018, Hydro One introduced the Leadership Operating System (LOS) to its Stations Services organization. The LOS 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 LOS drives continuous operational effectiveness by ensuring safety, quality of service and cost management.

In 2020, Hydro One started an initiative to extend this model to Stations Construction and plans to extend this model to Transmission Lines starting in 2021. The benefits of this program will be:

- Improved safety culture and engagement of crews, through enhanced field leadership tools and work execution rigour;
- Improved efficiency through reducing time spent on lower-value activities
- Increased project efficiency through the use of more consistent scheduling tools;
- Increasing coordination on projects to improve project management efficiency and reduce engineering rework; and
- Improved coordination of field activities on projects to reduce project durations.

2.10.6.4 TECHNOLOGY IMPROVEMENTS

Hydro One has made progress over the last five years in enhancing available technology. It has upgraded its project scheduling tool (Primavera P6) and installed new estimating software (SAGE). Hydro One has a technology roadmap that defines necessary future enhancements including the implementation of a Project Lifecycle Management (PLM) Tool, Field Scheduling solutions and mobile devices for field staff. The PLM tool will integrate disparate data sources into a single location that is easily accessed through improved dashboards, which will also provide enhanced reporting and analytics.

Integrating cost and schedule information through a single tool will provide the PMs and senior management with greater insight into how projects are performing. The resulting insights will lead to earlier identification of issues and overall improved forecasting. Hydro One also plans to install a new scheduling platform for Stations Construction and Transmission Lines that will integrate with the project scheduling tool and provide greater visibility to their entire work program housing both projects and programs in one solution.

2.10.6.5 SUMMARY

The benefits of introducing upstream efficiencies in the Project Definition phase as well as the evolution of the company’s delivery model strategy will result in tangible downstream improvements. Field workforce productivity will benefit from improved project planning as well as the change in field facing work practices. Hydro One anticipates that the improvements and efficiencies described in this exhibit will contribute to identifying incremental productivity savings as described in SPF Section 1.4.

2.10.7 CONCLUSION

Hydro One has demonstrated that it can execute a very large and growing capital work program while maintaining the needed flexibility 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 stage-gate 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 2.11 - TSP - MATERIAL INVESTMENT SUMMARY DOCUMENTS

2.11.1 INTRODUCTION

Transmission System Plan Investment Summary Documents (ISD) are attached to this section. ISDs are provided for any proposed capital expenditure within the TSP that exceeds a materiality threshold of $3M in a single year. ISDs for General Plant investments are provided under the General Plant System Plan (Exhibit B-04-01).

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T-SA-01	**NEW CUSTOMER CONNECTION STATION**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	13.5	13.5	0.0	0.0	0.0	27.0

Summary:

This investment involves building two new 230/27.6kV transformer stations and the associated connection lines. The primary trigger of the investment is a customer request for two new load connections. The planned in-service date is Q4 2024.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in an inability to connect the customer's load. This project has been assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to respond to a request from a customer to connect two facilities in the City of Toronto. Each facility will have a loading of about 60 MVA. The new facilities will be connected to the Cherrywood TS to Richview TS 230kV circuits C4R/C20R and the Parkway TS to Richview TS 230kV circuits P21R /P22R. The planned in-service date is Q4 2024.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in an inability to connect the customer's load. This project has been assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

The proposed investment involves providing electricity supply to two customer facilities. Hydro One has set up a separate project to connect each facility. Each project includes the following:

- Construction of a new 50/83 MVA , 230/27.6kV transformer station
- Construction of a dual 230kV line tap from the transmission circuits to the new transformer station; and
- Modification of the protection and control facilities for the transmission circuits at terminal stations to incorporate and integrate the new transformer station.

A map showing the location of the stations and customer facilities is provided below.

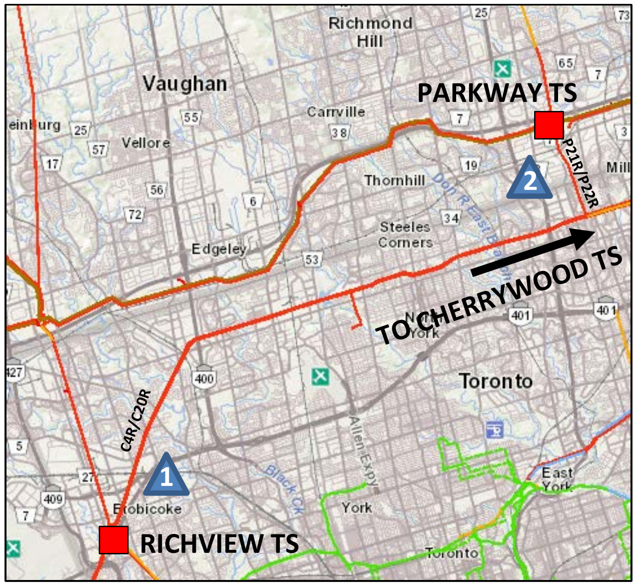

Figure 1: Location of the two Customer Facilities

Environmental approvals will be required for the new stations and associated lines. This work is planned to be completed by Q4 2022.

The project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be completed by Q4 2021.

Commencement of the project is subject to signing of the Connection Cost Recovery Agreement (CCRA) with the customer.

C. OUTCOMES

This investment will provide the required transmission facilities to supply power to the two new customer stations, with a projected load of 60MVA each.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer request for connection.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customer. The project costs and capital contribution amounts are considered preliminary as they will be finalized once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the investment cost incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	8.0	46.0	46.0	0.0	0.0	0.0	-	100.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**8.0**	**46.0**	**46.0**	**0.0**	**0.0**	**0.0**	**-**	**100.0**
Less Capital Contributions	8.0	32.5	32.5	0.0	0.0	0.0	-	73.0
Net Investment Cost	**0.0**	**13.5**	**13.5**	**0.0**	**0.0**	**0.0**	**-**	**27.0**

E. ALTERNATIVES

ALTERNATIVE 1: STATUS QUO

This alternative is not viable since this investment is in response to a specific customer request. Hydro One is obliged to provide connection pursuant to the Transmission System Code.

ALTERNATIVE 2: SUPPLYING CUSTOMER FACILITIES FROM 230KV CIRCUITS C4R/C20R AND P21R/P22R (RECOMMENDED)

The customer requested that Hydro One provide electrical supply to the customer facility. The nearest Hydro One transmission lines to the customer facilities are on the Cherrywood TS to Richview TS and the Parkway TS to Richview TS corridor. New step down stations will be built at the customer location and underground cable circuits will be built to connect the new station to the C4R/C20R and the P21R/P22R circuits.

F. 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: environmental approvals for the underground cable work, outage availability that is required for the work to be executed and timely customer approval of the CCRA. 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.

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T-SA-02	IAMGOLD - 115 KV MINE CONNECTION
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Load Connection

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	10.0	0	0	0	0	10.0

Summary:

This investment is required to facilitate the request from Iamgold Corporation (Iamgold) to provide supply to their Côté Gold Mine near Timmins, Ontario and to refurbish end of life transmission line facilities. The project involves reconductoring and energization of a 115 km section of the idle T2R circuit between Timmins and Shiningtree Junction, new switching facilities at Timmins TS, Shiningtree Junction and modification of the existing Northeast load rejection scheme. The project also includes refurbishment and reconductoring of the companion 115kV circuit T61S between the Timmins TS and Shiningtree Junction. The customer will construct and own 40 km of new circuit from their substation/mine site to Shiningtree Junction (Hydro One connection point). The planned in-service date is Q2 2023.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Hydro One also must address the safety and reliability risks associated with the T61S circuit. Not proceeding with this investment would result in an inability to connect the customer's load. This project has been assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to facilitate the request from Iamgold Corporation (Iamgold) to provide supply to their Côté Gold Mine near Timmins, Ontario. To supply power to the mine, the investment covers reconductoring and energization of the idle 115kV T2R circuit between Timmins Transformer Station (Timmins TS) and Shiningtree Junction (Shiningtree). This investment also includes replacement of the existing conductor on the 115 kV T61S circuit to address end-of-life sustainment needs as both circuits share common steel towers between Timmins TS and Shiningtree.

Iamgold is an established mining company building a new gold mine with expected load of approximately 70MW to be located about 40 km from Shiningtree. Shiningtree is an existing transmission junction 115 km south of Timmins that serves as the interconnection point between the customers' line and Hydro One's transmission system.

Transmission circuit T61S between Timmins TS and Shiningtree was built in 1931 and contains 336 KCMIL ACSR 30/7 conductor that has been verified through laboratory testing to be approaching end-of-life. This conductor has lost ductility and is therefore at increased risk of failure.[1] This investment will eliminate the safety and reliability risks associated with this circuit. Circuit T61S serves several customers including Lake Shore Gold Corp., local Hydro One Distribution connected communities and the Mattagami indigenous community.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. In addition, as fully explained in ISD T-SR-13, Hydro One must address the safety and reliability risks associated with conductor exhibiting lost ductility. Not proceeding with this investment, would result in an inability to

[1] See ISD T-SR-13 for a discussion of ACSR conductor.

connect the customer's load and increased risk to safety and reliability. This project has been assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

The proposed project consists of two components:

Provision of 115kV supply to the Iamgold Côté mine

- Reconductoring of the idle 115kV circuit T2R between Timmins TS and Shiningtree;
- Addition of switching facilities and line termination to connect the idle 115kV circuit T2R to Timmins TS;
- Installation of switching facilities at Shiningtree; and
- Incorporation of the customer facility into the existing Northeast Load Rejection scheme.

Refurbishment of 115kV circuit T61S

- Reconductoring of the 115kV circuit T61S between Timmins TS and Shiningtree.

A map showing the project location is provided below.

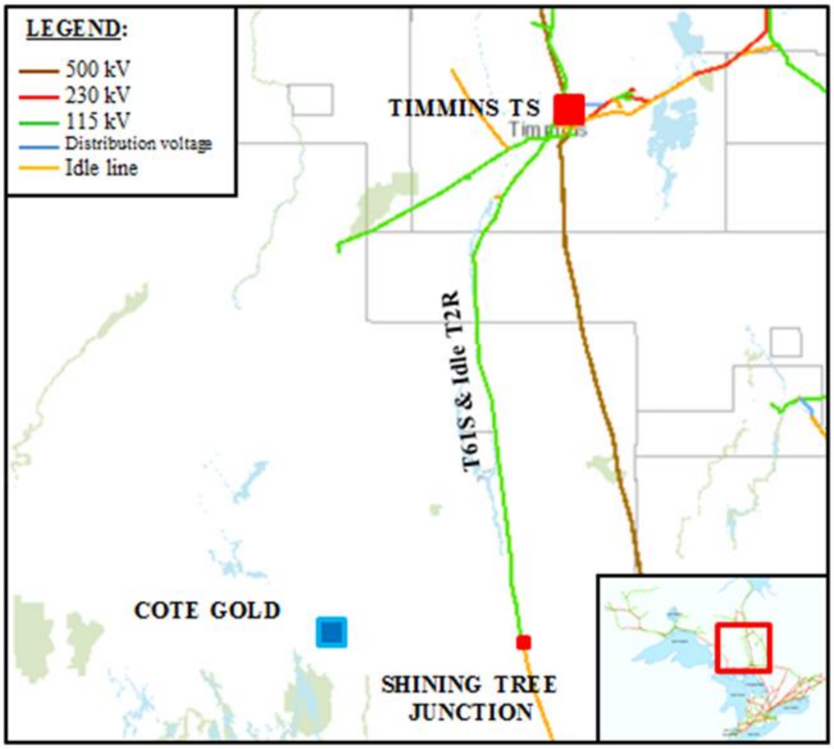

Figure 1: Map showing location of the Project

The System Impact Assessment and Customer Impact Assessment were completed in 2018, and both confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Hydro One has received approval from the OEB in Q1 2019 with respect to its “Leave to Construct” application (EB-2018-0257) for the reinforcement of the 115kV circuit (T2R) and refurbishment of circuit T61S under Section 92 of the Ontario Energy Board Act.

Iamgold had previously received approval from the OEB in Q4 2018 with respect to its “Leave to Construct” application (EB-2018-0191) under Section 92 of the Ontario Energy Board Act to allow the construction of the customer line from Hydro One’s Shiningtree to the Côté Mine.

Work on the project has commenced following signing of the Connection Cost Recovery Agreement (CCRA) with the customer on August 7, 2020.

C. OUTCOMES

This investment will provide the required transmission facilities to supply power to the new Côté Gold mine, which has a projected load of 70MW.

It will also satisfy Hydro One's license requirement to address load connection request, provide supply to customers requesting connection to the transmission system and maintain the safety and reliability of the transmission system.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer requests for connection. • The refurbishment of deteriorated 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.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and Transmission System Code to provide customers with non-discriminatory access. • Operating a line section with components that have deteriorated subjects that circuit to an increased likelihood of failure, which directly threatens reliable operation of the system. Line refurbishment will alleviate this threat.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers. • Realize cost savings by bundling the refurbishment of all components along the line section undergoing poor condition conductor replacement.

D. EXPENDITURE PLAN

This investment in circuit T2R is non-discretionary. The investment costs will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer. The costs and capital contribution amounts are considered preliminary and they will be finalized once the investment is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	41.8	23.3	0.0	0.0	0.0	0.0	-	65.1
Less Removals	6.1	0	0.0	0.0	0.0	0.0	-	6.1
Capital and Minor Fixed Assets	**35.8**	**23.3**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**59.1**
Less Capital Contributions	20.0	13.3	0.0	0.0	0.0	0.0	-	33.3
Net Investment Cost	**15.8**	**10.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**25.8**

E. ALTERNATIVES

ALTERNATIVE 1: STATUS QUO

This alternative is not viable since this investment is in response to a specific customer request. Hydro One is obliged to provide connection pursuant to the Transmission System Code.

ALTERNATIVE 2: SUPPLYING IAMGOLD FROM CIRCUIT T2R AND REFURBISH CIRCUIT T61S (RECOMMENDED)

The Customer requested that Hydro One provide electrical supply to the Côté Lake Mine facility. The nearest Hydro One transmission line is the 115kV double circuit transmission line T2R/T61S. The Customer's transmission line will be connected to the circuit T2R at Shiningtree and the circuit reconductored and energized between Shiningtree and Timmins TS. The circuit T2R will be connected to the 115kV network at Timmins TS via new switching facilities. The companion circuit T61S will be reconductored and refurbished at the same time.

F. EXECUTION RISK AND MITIGATION

This investment is under execution. COVID related delays, labour shortages, and equipment supply chain remain active risks for the project. The CCRA allows Hydro One to recover the actual costs incurred for such delays and costs that may be incurred outside of Hydro One's control.

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T-SA-03	**HALTON TS: BUILD A SECOND 230/27.6KV STATION**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	0.0	1.5	4.5	1.9	0.0	8.0

Summary:

This investment is required to facilitate a request from Milton Hydro to increase transformation capacity to accommodate forecasted customer load growth in the Town of Milton. Milton Hydro's required in-service date is Q2 2027.

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. This project has been assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to facilitate a request from Milton Hydro to increase the transformation capacity to accommodate forecasted customer load growth in the Town of Milton. The May 2019 GTA West Need Assessment Study,[1] carried out under the Regional Planning process, had identified a need date of Q2 2022. However, Milton Hydro has recently advised that it has deferred the need date for the new facility to spring 2027. The required in-service is now Q2 2027.

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. This project has been assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

The proposed project 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. 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 170MVA.

The proposed investment is intended to provide relief solely for Milton Hydro load, as any increase in Halton Hills Hydro load will be supplied from the recently built Halton Hills Hydro Municipal Transformer Station (MTS), which went into service in Q2 2019.

[1] Need Assessment Report GTA West.pdf

A map showing the project location is provided below.

Figure 1: Second DESN to be added at Halton TS

The System Impact Assessment and Customer Impact Assessment will be completed for the project by Q4 2024 to confirm that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Commencement of the project is subject to signing a Connection Cost Recovery Agreement (CCRA) with the customer.

C. OUTCOMES

This investment will provide the transformation capability required to meet Milton Hydro's forecast customer load growth.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - 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.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary as it is required to meet customer load growth. The project costs, as presented in the table below, will be recoverable through incremental revenue from the appropriate rate pool and a capital contribution from the customer. The project costs and capital contribution amounts are considered preliminary and will be finalized once the project is placed in-service, subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	**-**	**0.0**	**5.4**	**14.8**	**11.9**	**2.7**	**-**	**34.9**
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	-	0.0	5.4	14.8	11.9	2.7	-	34.9
Less Capital Contributions	-	0.0	3.9	10.3	10.0	2.7	-	26.9
Net Investment Cost	**-**	**0.0**	**1.5**	**4.5**	**1.9**	**0.0**	**-**	**8.0**

E. 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 was rejected because other stations in the area either have no capacity or are located further from the Milton Hydro load center and thus were ruled out because of the challenges associated with arranging supply from a more distant station. Therefore, this alternative was not considered further.

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 needed capacity. This recommended alternative is in accordance with the recommended plan in the GTA West Regional Infrastructure Plan for providing additional capacity to support the area's growth.

F. 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-04	CONNECT METROLINX TRACTION SUBSTATIONS
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	3.5	3.6	0.8	0.0	0.0	8.0

Summary:

This investment involves new 230kV connections to six Metrolinx traction power substations (TPSS) as part of the GO Transit electrification initiative. The primary trigger for the investment is a Customer Request from Metrolinx. The investment is expected to facilitate electrification of the GO Transit rail network by providing the required electric supply to TPSS.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in Metrolinx's inability to proceed with GO Transit electrification. This investment has been assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to address a request from Metrolinx (the Customer) by providing connections to six traction power substations (TPSS) that are required as part of the GO Transit electrification initiative.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in Metrolinx's inability to proceed with its GO Transit electrification. This investment has been assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

Metrolinx is electrifying the GO Transit rail network across the Greater Toronto Area as part of a multi-year program. The electrification requires construction of six TPSS to provide power along the GO rail corridors. Each Metrolinx TPSS is planned to be located adjacent to Hydro One's existing transmission circuits and will require a dual 230kV supply. Table 1 lists the forecasted load demands, supply circuits and updated in-service date required by Metrolinx for each TPSS connection. Locations of the six Metrolinx TPSS are shown in Figure 1 below.

Table 1 - TPSS Loads, Supply and Planned In-Service Dates

No.	Traction Power Substation	MW Load	Supplied from 230kV Transmission Circuits	Required In-service date
1	Mimico	26	K21C / K23C	Q1 2024
2	City View	28	V73R / V77R	Q1 2024
3	Burlington	12	B40C / B41C	Q4 2024
4	Allandale	10	E28 / E29	Q1 2025
5	Scarborough	41	C2L / C14L	Q4 2024
6	East Rail Maintenance Facility	22	T24C / T26C	Q1 2025

Hydro One has set up six separate projects, one for each of the TPSS connections. Each of the proposed projects involves the following tasks:

- Construction of a dual 230kV line tap from the transmission circuits to the Metrolinx TPSS; and
- Modification of the protection and control facilities for the transmission circuits at terminal stations to incorporate and integrate the TPSS.

A map showing the stations location is provided below.

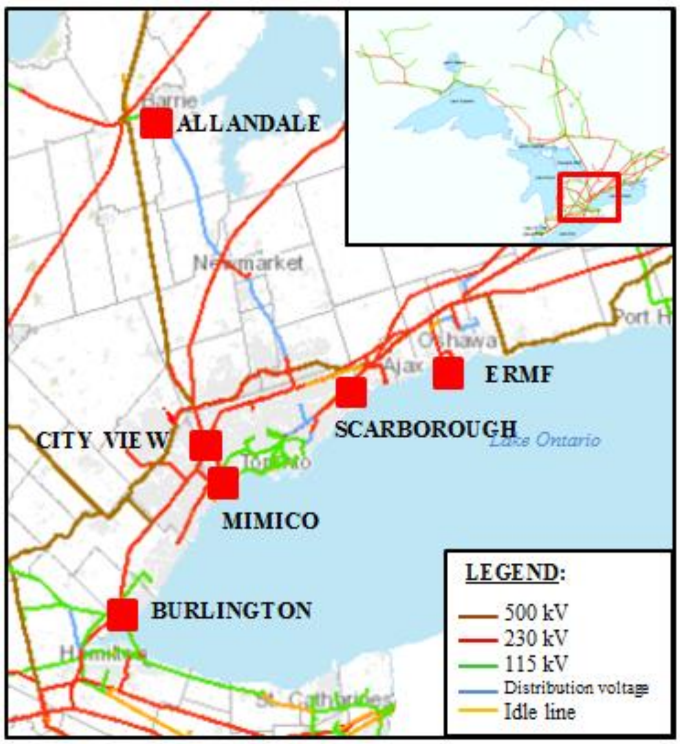

Figure 1: Locations of the Six Metrolinx TPSSs

System Impact Assessments and Customer Impact Assessments were completed for all six of the Metrolinx TPSS connections over the 2017 and 2018 period. The assessments confirmed that the investment will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. This investment does not require a Section 92 application.

The execution of each of the TPSS connection is subject to signing a Connection Cost Recovery Agreements (CCRA) with the Customer for each station. At present, Hydro One is developing

Release-for-Construction quality drawings for the six TPSS connections as requested by the Customer.

C. OUTCOMES

This investment will facilitate electrification of the GO Transit rail network by providing the required electric supply to Metrolinx TPSSs.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 – Outcomes Summary

Customer Focus	• Satisfy customer requests for connection.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and Transmission System Code to provide customers with non-discriminatory access. • Support Provincial GO Regional Express Rail Initiative.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The investment costs will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer. The costs and capital contribution amounts are considered preliminary and will be finalized once the investment is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 3 summarizes historical and projected spending on the aggregated investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 3 – Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	0.6	10.0	12.2	2.5	0.0	0.0	-	25.3
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**0.6**	**10.0**	**12.2**	**2.5**	**0.0**	**0.0**	**-**	**25.3**
Less Capital Contributions	0.6	6.5	8.6	1.7	0.0	0.0	-	17.4
Net Investment Cost	**0.0**	**3.5**	**3.6**	**0.8**	**0.0**	**0.0**	**-**	**8.0**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This alternative is not viable since this investment is in response to a specific customer request. Hydro One is obliged to provide connection pursuant to the Transmission System Code.

ALTERNATIVE 2: CONNECTING TPSS AT REQUESTED LOCATIONS (RECOMMENDED)

Hydro One and Metrolinx have explored multiple tapping location and supplying circuit alternatives. The options listed in Table 1 are identified as the most feasible solutions and are designed to achieve the lowest cost possible. This alternative is recommended since it enables Metrolinx GO Rail electrification using the most feasible and lowest cost connection options

F. EXECUTION RISK AND MITIGATION

No major execution risk is expected. The risks that may affect the timely completion of the project are availability of required outages and interfacing complexity between Hydro One and

Metrolinx's protection and control systems. These risks will be mitigated by working with the customer on setting a schedule that aligns with outage availability and early coordination at design stage. There is also a risk that the customer requirements may change resulting in a delay or cancellation of the need for this investment. The CCRA will allow Hydro One to recover the actual costs incurred even if the customer ultimately decides to cancel the investment.

T-SA-05	FUTURE TRANSMISSION LOAD CONNECTION PLANS
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	3.1	5.2	9.4	10.4	10.4	38.5

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. This investment anticipates load customer requests that are expected to arise during the test period, but are currently unknown. The costs have been forecasted based on typical costs incurred for new load connections over the past five-year period.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. This investment has been assigned a High Priority to ensure future customer needs are addressed in a timely manner.

A. NEED AND OUTCOME

A.1 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.

Hydro One is obligated to make connections when requested by customers in accordance with its Transmission License and the Transmission System Code. This investment has been assigned a High Priority to ensure future customer needs are addressed in a timely manner.

B. INVESTMENT DESCRIPTION

This investment has been established to cover future load connection projects anticipated in the test 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. A project may also be initiated by regional planning needs or to address end-of-life connection facilities.

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
- New transformer stations.

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.

C. 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 issues.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer requests for connection, increased capacity, improving 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.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The investment covers multiple projects, and the costs, as presented in the table below, have been forecasted based on typical costs incurred for new load connections over the past five-year period. The individual project costs will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customer(s), determined on a project-by-project basis as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code. The project costs and capital contribution amounts are considered preliminary and are only finalized 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*, the proposed expenditures will be tested during the Section 92 process.

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028	Total
Gross Investment Cost	-	5.2	23.9	26.0	27.0	27.0	-	109.1
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**-**	**5.2**	**23.9**	**26.0**	**27.0**	**27.0**	**-**	**109.1**
Less Capital Contributions	-	2.1	18.7	16.6	16.6	16.6	-	70.6
Net Investment Cost	**-**	**3.1**	**5.2**	**9.4**	**10.4**	**10.4**	**-**	**38.5**

E. 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.

F. 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

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	0.0	0.0	0.0	0.0	0.0	0.0

Summary:

This investment is needed to perform the necessary protection and control upgrades on Hydro One's transmission system to preserve its loading and protection capability in order to accommodate the connection of distributed energy resources (DERs) on Hydro One's distribution and other 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 upstream transmission protection system in order to maintain safe and reliable operation of the distribution and transmission systems.

Hydro One is obligated to connect DERs when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in new DERs not being able to connect. This program is assigned a High Priority in order to meet mandated obligations to customers.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is needed to perform the necessary protection and control upgrades on Hydro One transmission system to preserve its loading and protection capability in order to accommodate the connections of distributed energy resources (DERs) on Hydro One's distribution and other local distribution company (LDC) 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 system in order to maintain safe and reliable operation of the distribution and transmission systems.

Hydro One is obligated to connect DER when requested by customers in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in new DERs not being able to connect. This program is assigned a high priority in order to meet mandated obligations to customers.

B. INVESTMENT DESCRIPTION

Since the end of the Feed-in Tariff (FIT) Program in 2017, DER activity in Ontario has undergone a major shift from retail generators participating in different IESO programs such as the FIT Program, Renewable Energy Standard Offer Program, and Hydroelectric Energy Standard Offer Program to behind-the-meter (BTM) load displacement generators (LDGs) participating in the IESO's Industrial Conservation Initiative (ICI) and the Ontario Net Metering Program.

In order to accommodate the connection of generation to the distribution system, 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 a safe interconnection for the distributed generators. All the transmission costs required for connecting new DERs to Hydro One and 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 in order to prevent false tripping;
- Bus protection modification to prevent mis-operation;
- Line back-up protection installation to protect transmission assets from distributed generators' fault current contribution;
- Transfer trip signalling installation to prevent distributed generation 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).

C. 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.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer requests for connection of DERs to Hydro One and other LDC distribution systems.
Operational Effectiveness	• Preserve the loading and protection capability of the transmission system while incorporating renewable generation.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.
Financial Performance	• The investment costs are 100% recoverable through capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The program costs, as presented in the table below, will be fully recoverable through capital contributions from the customers. The gross costs have been forecast based on current DER customer requests, and anticipated future requests resulting from the IESO Industrial Conservation Initiative (ICI) program. The program costs and capital contribution amounts are considered preliminary as they will be finalized only once the investment is placed in-service subject to the terms of a CCRA. The capital contributions are determined in accordance with Hydro One's Transmission Customer Contribution Policy and the Transmission System Code.

Table 2 below summarizes historical and projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years[1]	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	-	4.0	4.0	4.0	3.0	3.0	-	18.0
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**-**	**4.0**	**4.0**	**4.0**	**3.0**	**3.0**	**-**	**18.0**
Less Capital Contributions	-	4.0	4.0	4.0	3.0	3.0	-	18.0
Net Investment Cost	**-**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**0.0**

[1]For programs: Due to the in-year nature of program investments, only 2023-2027 expenditures are shown.

E. 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.

F. 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	**SECONDARY LAND USE PROJECTS**
Primary Trigger:	Mandated Obligations
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	37.8	2.8	2.8	0.8	0.8	45.0

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 those outlined below in this ISD.

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.

A. NEED AND OUTCOME

A.1 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.

The Province of Ontario has established a Provincial Secondary Land Use Program that allows for third-party uses within Hydro One transmission corridors, while recognizing that the primary use of these lands is for Hydro One's electricity infrastructure. In certain locations it is not possible to accommodate certain proposed secondary land uses without relocating or modifying Hydro One assets. This investment is required to fund these relocations and modifications. As such, it is non-discretionary and has been assigned a High Priority given Hydro One's obligations and the requirements of a broad group of stakeholders, which include municipalities, third-party developers, pipeline companies, Metrolinx, and the Ontario Ministry of Transportation (MTO).

B. INVESTMENT DESCRIPTION

The proposed investment involves accommodating third-party requests to utilize Hydro One's transmission corridors for secondary 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 on Hydro One's behalf.

The material investments forecast over the plan period, including the estimated 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 expansions, and development projects adjacent to or crossing Hydro One's right-of-way.

Table 1 - List of Material Investments

No	Project Name	Description	Total Gross ($M)
1	**MTO – Highway 401 and Highway 6 Expansion** *Proponent: MTO*	MTO is looking 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. The capital costs associated with this investment are 100% recoverable from MTO.	**5.0**
2	**Metrolinx – Don Yard Relocation** *Proponent: Metrolinx*	Metrolinx has announced improvements to the Union Station GO rail corridor that include an upgrade and expansion of the Don Yard train storage facility. To accommodate Metrolinx's planned development, Hydro One must relocate the existing 115kV transmission circuits (H9EJ/H10EJ) and the 115kV underground cable (circuit H2JK) into a new all-underground configuration. This investment has an estimated cost of $21.7M which will be recovered via capital contribution from Metrolinx.	**21.7**
3	**Metrolinx – Barrie Rail Corridor** *Proponent: Metrolinx*	Metrolinx has identified improvements to its Barrie GO rail corridor that include the expansion to the rail corridor from one track to two tracks, electrification of the corridor, and the addition of a new GO station with two pedestrian platforms. A section of the Hydro One double-circuit line K1W/K3W is located within the rail corridor between Eglinton Avenue West and St. Clair West Avenue in Toronto. To accommodate Metrolinx's planned development, Hydro One must relocate the 115kV double-circuit line (K1W/K3W) underground.	**40.0**

**Note: The Total Gross includes the total cost of the project, including any costs prior to the test years, if applicable.*

C. 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.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcome Summary

Customer Focus	• 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 secondary land uses on Hydro One rights-of-way through the relocation and modification of transmission facilities to accommodate compatible uses that conflict with existing transmission assets.
Financial Performance	• In most circumstances, the investment costs are fully recoverable from proponents except for certain situations where Hydro One may be required to cover costs under pre-existing agreements.

D. EXPENDITURE PLAN

Table 3 below summarizes historical and projected spending at the aggregate investment level. This investment is non-discretionary. The investment costs, as presented in the table below, are typically recoverable through capital contributions from the proponents; however, some of the investments outlined in Table 1 above present unique situations where Hydro One is responsible for significant portions of the investment cost. The size and complexity of these investments vary from year to year; the planned investment cost is based on preliminary estimates for the investments, which are in various stages of development. The "Previous Years" costs are the direct costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years[1]	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	**51.3**	**46.7**	**5.5**	**4.9**	**1.9**	**1.9**	-	**112.2**
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**51.3**	**46.7**	**5.5**	**4.9**	**1.9**	**1.9**	**-**	**112.2**
Less Capital Contributions	40.3	8.9	2.7	2.1	1.1	1.1	-	56.2
Net Investment Cost	**11.0**	**37.8**	**2.8**	**2.8**	**0.8**	**0.8**	**-**	**56.0**

[1]*Includes costs for listed projects incurred prior to the rate period*.

E. 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

Hydro One works with third parties that propose secondary 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, consistent with Provincial Secondary Land Use principles, 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.

F. 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.

T-SA-08	**H29/H30: RECONDUCTOR 230KV CIRCUITS**
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	0.2	0.4	0.3	2.1	2.3	5.3

Summary:

This investment is required to upgrade the 230kV double circuit line H29/H30 supplying Pleasant TS to be able to meet forecast load growth. The upgrade work covers replacing the existing line conductor with a higher current-rated conductor because the existing thermal rating of the circuits is not sufficient to carry forecasted load growth at Pleasant TS. The primary trigger of the investment is increased customer demand. 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 facilities 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. This investment is assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to upgrade the 230kV double circuit line H29/H30 supplying Pleasant TS to be able to meet forecast load increase as documented in the 2016 GTA West Regional Infrastructure Plan (SPF Section 1.2, Attachment 6) and the 2019 Needs Assessment for GTA West.[1] The latest 2020 Pleasant TS forecast developed as part of the currently underway GTA West IRRP Study, indicates that the line capacity is now expected to be exceeded by summer 2027. The in-service date for this investment is now Q2 2027.

Hydro One is obligated to provide facilities 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. This project is assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

The proposed 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] Needs Assessment - GTA West.pdf

A map of the location is given below:

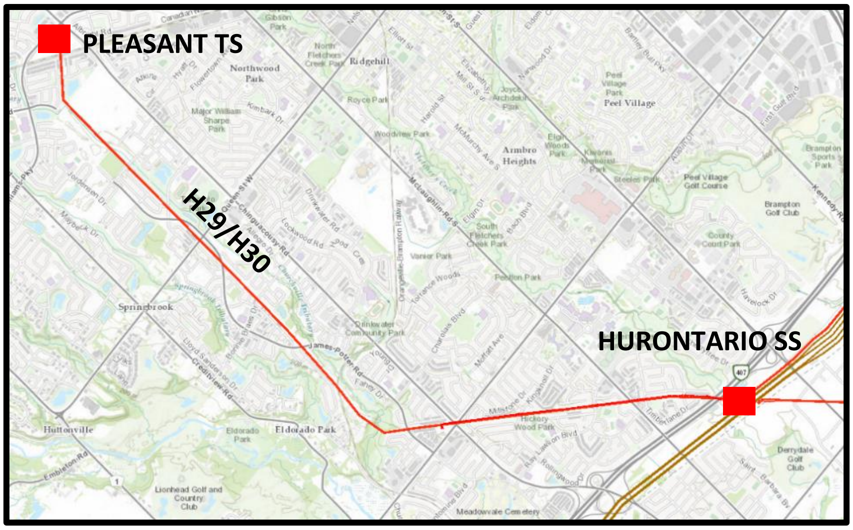

Figure 1: Radial Circuits of H29/H30 Supplying Pleasant TS

Hydro One will apply for a “Leave to Construct” approval under Section 92 of the Ontario Energy Board Act, and a Class Environmental Assessment approval under the Environmental Assessment Act in Q4 2024. A summary of the need, investment description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

The project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be completed prior to the submission of the Section 92 application.

C. OUTCOMES

This investment will provide adequate capacity to meet forecast load growth at Pleasant TS.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Ensure adequate capacity to supply Pleasant TS loads
Operational Effectiveness	• Improve operation flexibility as a result of increase in capacity
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to expand transmission system to support load growth
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The investment costs will be recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers.

The investment costs and capital contribution amounts are considered preliminary as they will be finalized once the investment is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes forecast spending at the aggregate investment level.

The investment costs and capital contribution amounts are considered preliminary as they will be finalized once the investment is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	-	0.2	0.8	0.3	3.3	3.4	-	8.0
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**-**	**0.2**	**0.8**	**0.3**	**3.3**	**3.4**	**-**	**8.0**
Less Capital Contributions	-	0.0	0.4	0.0	1.2	1.1	-	2.7
Net Investment Cost	**-**	**0.2**	**0.4**	**0.3**	**2.1**	**2.3**	**-**	**5.3**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The Status Quo alternative is not considered a viable alternative 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 with a higher current rating. The 2016 GTA RIP and the 2019 Needs Assessment both have identified this as the most effective solution to address the capacity limitation.

F. EXECUTION RISK AND MITIGATION

The risks associated with the execution of this investment as planned arise from potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment 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

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	0.0	0.0	5.6	3.7	2.4	11.7

Summary:

This investment involves building a new 230/44kV transformer 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. The planned in-service date of this investment is Q2 2027.

Hydro One is obligated to provide facilities 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 transformation capacity to supply projected customer demand in the area. This project is assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 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 Regional Infrastructure Plan (SPF Section 1.2, Attachment 5). The planned in-service date of this investment is Q2 2027.

Hydro One is obligated to provide facilities 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 transformation capacity to supply projected customer demand in the area. This project is assigned a High Priority in order to meet this customer obligation.

B. INVESTMENT DESCRIPTION

The investment involves the construction of a new 230/44 kV DESN station with two 75/125MVA transformers along with a new 44 kV switchyard at a new site pursuant to the recommended approach in the GTA North Regional Infrastructure Plan. The new transformer station will be supplied by 230 kV transmission circuits B88H/B89H which run between Holland TS and Brown Hill TS. This work will increase the transformation capacity in Northern York Region by about 150 MW.

A map showing the project location is provided in Figure 1 below.

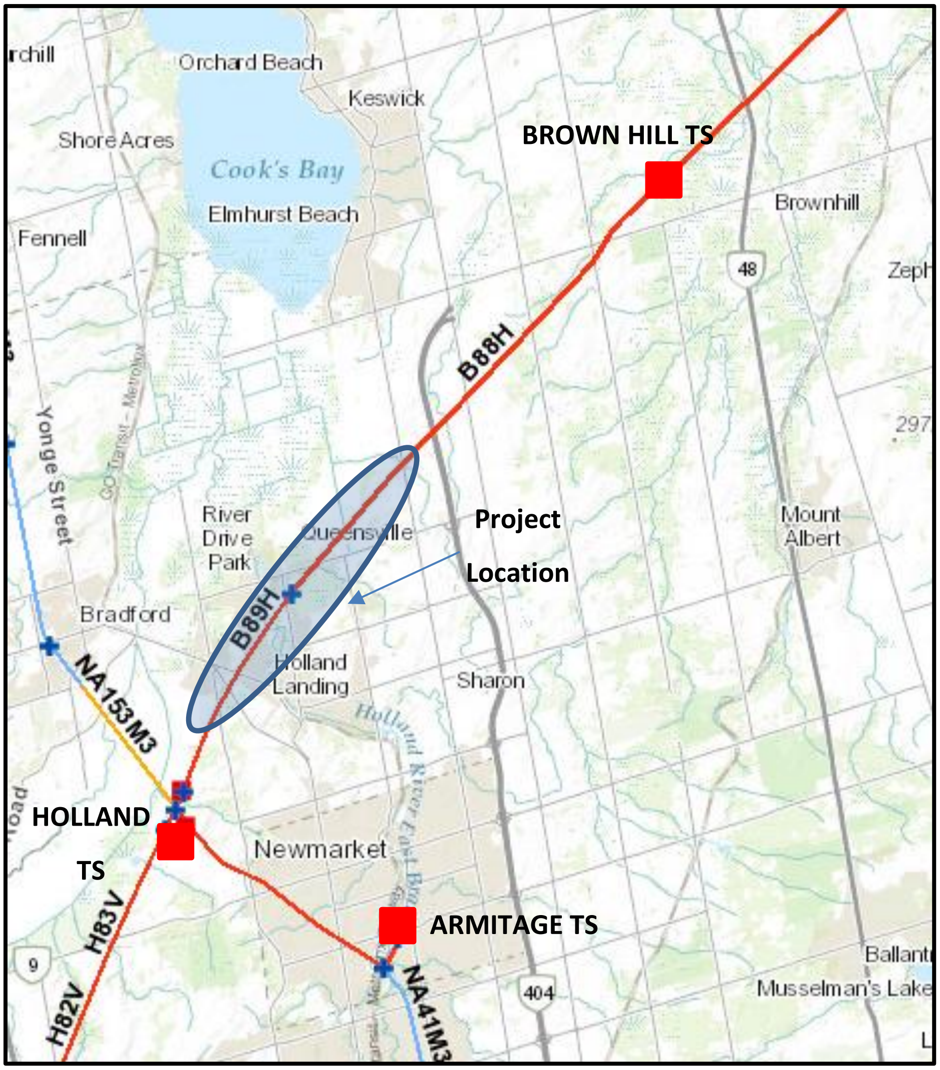

Figure 1: Area Where New Transformer Station Will Be Located

The System Impact Assessment and Customer Impact Assessment will be completed for the project by Q4 2024 to confirm that it will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers.

Commencement of the project is subject to signing a Connection Cost Recovery Agreement (CCRA) with the local distribution companies, Alectra Utilities, Newmarket-Tay Power Distribution and Hydro One Distribution, that would be supplied from the new station.

C. OUTCOMES

This investment will provide the required increase in transformation capacity to supply load growth in Northern York Region.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcome Summary

Customer Focus	• Satisfy customer need for additional transformation capacity.
Operational Effectiveness	• Increase transformation capacity and improve operation flexibility, with the addition of a new DESN.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary because it is required to meet forecasted customer load growth in the Northern York Region. The project costs, as presented in the table below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contributions from customers. The forecast project costs and capital contribution amounts are considered preliminary as they will be finalized only once the project is placed in-service subject to the terms of the CCRA. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes historical and projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	-	0.4	2.0	15.0	10.0	7.6	-	35.0
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	-	**0.4**	**2.0**	**15.0**	**10.0**	**7.6**	-	**35.0**
Less Capital Contributions	-	0.4	2.0	9.4	6.3	5.2	-	23.3
Net Investment Cost	-	**0.0**	**0.0**	**5.6**	**3.7**	**2.4**	-	**11.7**

E. 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 License.

ALTERNATIVE 2: BUILD A NEW TRANSFORMER STATION IN NORTHERN YORK REGION (RECOMMENDED)

Build a new transformer station at a new site in Northern York Region, which includes acquiring a new site and connecting it to existing 230kV lines to supply the new station as discussed above.

ALTERNATIVE 3: SUPPLY LOAD GROWTH FROM BROWN HILL TS

Brown Hill TS is located too far from the area of forecasted load growth. This alternative is therefore not recommended.

Alternative 2 is the recommended and only practical alternative to provide the needed capacity. Hydro One will work with the area LDCs to determine a suitable site.

F. 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. As the station 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 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 CCRAs will allow Hydro One to recover the actual costs incurred even if the project is ultimately delayed or cancelled.

T-SA-10	**BUILD LEAMINGTON AREA TRANSFORMER STATIONS**
Primary Trigger:	Customer Request
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness,

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	7.6	40.9	33.5	14.5	32.6	129.1

Summary:

This investment involves the building of three Dual Element Spot Network (DESN) stations in the Kingsville – Leamington area in order to increase load supply capability to meet the requirements of customers to connect load. The primary trigger of the investment is area load growth and customer's request for load connection.

Hydro One is obligated to connect customers and to provide facilities 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 connect new customers or supply the forecast area loads. This investment is assigned a High Priority in order to meet this customer obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to increase load supply capability 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 Windsor – Essex Integrated Regional Resource Planning (IRRP) studies and bulk system planning studies by the IESO.[1][2] An addendum to the Windsor-Essex IRRP is slated to be published in Q3 2021, further defining additional regional infrastructure required to support the continued growth in the region.

Hydro One is obligated under its Transmission License 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 customers' need in this area. This investment is assigned a High Priority given the requirement to meet customer needs in a timely manner.

B. INVESTMENT DESCRIPTION

This investment involves the building of three Dual Element Spot Network (DESN) stations in the Kingsville – Leamington area.

Hydro One proposes to develop this investment in three stages. Each stage will address station work to enable customer connections, as follows:

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[1] "*Need for Bulk Transmission Reinforcement in the Windsor-Essex Region*", IESO, Published June 13, 2019
[2] "*2019 Windsor-Essex Integrated Regional Resource Plan (IRRP)"*, IESO, Published September 3, 2019

- Stage 1: Leamington Area Station #4, Target In-Service for Q3 2025
  - Build a new 75/125MVA, 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 2026
  - Build a new 75/125MVA, 230-27.6kV station with twelve feeders plus necessary switching and capacitive reactive facilities about 2.5km north-east of Kingsville TS.
- Stage 3: Leamington Area Station #6, Target In-Service for Q4 2028
  - Build a second new 75/125MVA, 230-27.6kV DESN station with twelve feeders plus necessary switching and capacitive reactive facilities, at about 5.5km North of DESN #5.

At the request of the IESO, Hydro One is currently in the process of developing the Lakeshore Transformer Station, to be located near Leamington Junction slated for completion in mid-2022, and a new 230 kV line from Chatham SS to the Lakeshore station (ISD T-SS-07). The incorporation of these two facilities into the Ontario grid will reinforce the system such that the development of this investment will not adversely affect the reliability of the IESO-controlled grid, or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be undertaken to confirm these conclusions.

A map showing the project location is provided below.

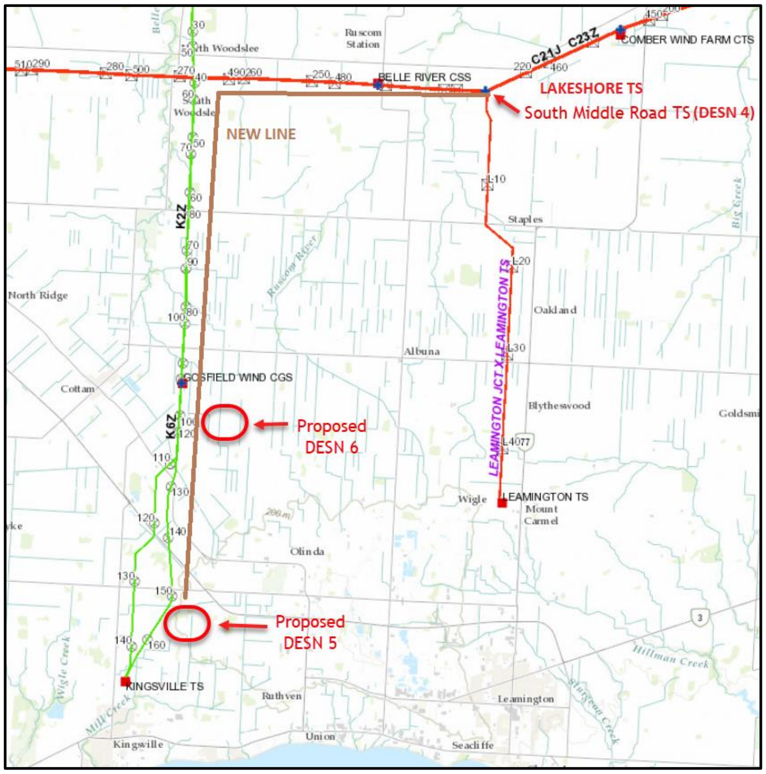

Figure 1: Map showing location of the new facilities

The connection of Stage 2 and 3 is dependent on the construction of a new transmission line approximately 20km from Lakeshore TS into the Kingsville area. The new transmission line is expected to be owned by and included in the rate base of a newly licensed partnership. These assets will not form part of Hydro One's rate base and, as such, the associated capital expenditures have been excluded from the 2023-2027 forecast. Funding for this line will be sought pursuant to the approach discussed in Exhibit A-03-01.

Hydro One will initiate a Class Environmental Assessment process, as required under the Environmental Assessment Act, for the above referenced transmission line in Q2 2022 and approvals are expected to be obtained by Q3 2023.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the Ontario Energy Board Act in Q4 2023 for the new transmission line from Lakeshore TS into the Kingsville area. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

C. OUTCOMES

This investment will provide the required increase in transformation capacity to supply load growth in Kingsville-Leamington area.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Satisfy customer request for additional capacity.
Operational Effectiveness	• Enhance reliability of supply in the Kingsville - Leamington area
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, will be fully recoverable through incremental revenue from the appropriate rate pool and capital contribution from the customers. The project costs and capital contribution amounts are considered preliminary as they will be finalized only when the project is placed in-service subject to the terms of the Connection Cost Recovery Agreement (CCRA). The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The “Previous Years” costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in “Forecast 2028+” are investment costs forecast beyond 2028, recognizing that rapid growth in the area may further impact future spend.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	1.0	7.6	40.9	33.5	14.5	32.6	5.7	135.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**1.0**	**7.6**	**40.9**	**33.5**	**14.5**	**32.6**	**5.7**	**135.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.0**	**7.6**	**40.9**	**33.5**	**14.5**	**32.6**	**5.7**	**135.9**

E. 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. There will be insufficient transformation capacity to supply customer load growth. This would violate the conditions of Hydro One’s Transmission License.

ALTERNATIVE 2: STAGED DEVELOPMENT OF NEW STATIONS IN THE LEAMINGTON AREA (RECOMMENDED)

A staged development of the investment is recommended, with the first stage being the development of a new station at the South Middle Road TS site situated near Lakeshore TS. The second stage development involves constructing a new station approximately 2.5km north-east of the existing Kingsville TS followed by a third station approximately 5.5km north of station constructed in the second stage. The proposed station sites have been determined on the basis of customer applications for connection and effective routing of distribution feeders. The need for these additional transformation and customer stations have been identified through the Regional Planning process for the Windsor-Essex region, for which an addendum to the IRRP is currently underway by the IESO.

F. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would include potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment process in a timely manner. There is potential for normal project risks that may affect the timely completion of the project, such as system outage availability that is required for the work to be executed. As the station 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 on setting 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.

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T-SR-01	TRANSMISSION STATION RENEWAL - NETWORK STATIONS
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	209.4	199.6	213.6	158.4	213.1	994.1

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 high risk of asset failures, deteriorated condition and 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.

A. 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, 500kV, 230kV and 115kV high-voltage transmission lines, and generation facilities. The North America Electric Reliability Corporation (NERC) develops reliability standards applicable the BES system 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 (the "Investment") manages asset-failure related risks to stations performance and operational effectiveness with the replacement of key station assets that have been verified to be in poor condition. The Investment involves a series of individual investments and includes the replacement of multiple assets within a particular station. The scope of each investment comprising the Investment includes 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.

Since 2014, Hydro One has successfully utilized an integrated approach to station asset management where prudent. In particular, the integrated approach allows Hydro One to replace multiple key transmission assets, such as transformer, breakers, switchgear and protection and control equipment, within a transmission station. The integrated approach is primarily driven by the complexities of transmission stations, outage scheduling and the extended lead timelines required to replace deteriorated assets. By employing the integrated approach, Hydro One can complete the necessary asset replacements at a particular station at once as opposed to requiring multiple visits to replace individual assets which would result in re-engineering, repeated construction mobilization, and increased planned outages coordination at the same work location within a small time period. In a lot of instances, initiating multiple projects at a single station is simply not feasible. When transmission stations are reviewed and analyzed by transmission planners, there is an opportunity to review transmission stations for operational improvements and consult with customers to ensure refurbished transmission stations meet the needs of Hydro One customers and leverage alignment with customer planned outages.

Within each network station, there are the following critical transmission assets: (i) power auto-transformers that convert voltages from higher to lower transmission level voltages, (ii) circuit breakers and protection systems that protect the transmission station assets, customer equipment, and reduce outages, (iii) switchgear that facilitates the transfer of power, through transmission lines, to remote network stations and connection stations. Critical transmission station assets degrade over time. Hydro One does not run its transmission station 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. Once an asset is confirmed to be in poor condition, replacement options are assessed.

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 customer's expect from their transmitter and does would not meet the standards mandated by NERC and NPCC.

To mitigate risks associated with poor condition assets, Hydro One evaluated several alternatives, as further described below, and concluded that continued targeted replacement of poor condition network station assets is the most prudent alternative, and is required to meet NERC and NPCC standards. To optimize the amount of risk mitigated in the pacing of investments, Hydro One prioritizes investments based on asset demographics, condition, performance, environmental and safety concerns, customers, and load served.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

The Investment focuses on the replacement of multiple transmission station assets that facilitate power transformation from a high transmission voltage to a lower transmission voltage. The Investment utilizes a bundled approach that targets multiple assets within a network station confirmed to be in poor condition. Operating assets that are in poor condition pose an increased risk of failures or risk 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 neighboring 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 NPCC and is registered under NERC's compliance registry. As a licensed transmitter, Hydro One is required to comply with the planning, operating and reliability criteria and standards adopted by NERC and NPCC. This reliability framework is based on the reliability standards established by NERC, as adopted and enforced in Ontario by the IESO. NERC standards are intended to ensure the integrity not only of the Ontario BES but of all of the interconnected bulk electricity systems across North America. 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 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). Such failures are nonetheless 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.

As discussed in TSP Section 2.2, 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 cancellation or rescheduling of planned outages for maintenance 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, such as oil-filled transformers, oil-filled circuit breakers and gas-filled circuit breakers, increases environmental and safety risks. Environmental risks include oil leaks and gas leaks. As transformers and circuit breakers age and deteriorate in condition, one issue that can materialize is oil leaks. Deterioration of gasket and O-rings results in oil leaks from oil-filled transformers and circuit breakers and in gas leaks from SF6 gas-filled circuit breakers. When transformers and breakers are replaced, Hydro One follows the latest environmental standards to ensure oil leaks will be contained. 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. Oil-filled equipment may explode resulting in fires, which may further damage surrounding equipment and injure personnel.

An example of a failure at a network station is the 2015 Richview TS drop leads failure that resulted in faults on three lines, a momentary interruption of 58 MW of load at Rexdale TS and approximately 700 MW of sympathetic load loss throughout Ontario. Numerous Digital Fault Recorders and power quality meters throughout Southern Ontario recorded severe voltage depressions during each of the faults. Another example of a failure is the 2018 Longwood TS T4 autotransformer failure. The T4 unit, placed in-service in 1990, suffered a sudden and severe internal phase-to-ground fault. Protection systems automatically operated correctly to immediately remove the failed unit from service. However, the severity of the fault caused an internal pressure rise within the transformer’s main tank and ultimately resulted in catastrophic rupture and failure of T4. The transformer tank rupture released approximately 87,000 liters, out of a total 130,500 liters, of mineral oil. Fortunately, no further serious environmental consequences or fire resulted from the rupture of T4.

The condition of transformers, breakers, and the age of protection and control systems are the leading indicators of the assets’ performance that may eventually lead to catastrophic events, 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 poor condition category as the condition of the asset continues to deteriorate over time. This deterioration is not reversible. Key station assets demographics and condition are further described below.

Transformer Condition – Network stations

As discussed in TSP Section 2.2, transformer condition is a leading indicator of performance and the main driver for replacement. Where feasible, Hydro One maximizes the life of poor condition transformers by undertaking certain remedial actions. However, this solution is temporary in nature and requires ongoing monitoring. Based on Hydro One's experience, these transformers will have to be replaced in the near future.

Transformer condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Hydro One retained a third party expert, EPRI, to provide an independent assessment of the condition of the transformers that Hydro One determined to be in poor condition. EPRI used its PTX Software to examine the condition of the transformer's main tank insulating oil condition. EPRI's analysis confirmed the degraded condition of most of these poor condition transformers. There are also transformers that EPRI was not able to validate based on main tank oil sampling, because Hydro One primarily selected those transformers for replacement based on factors other than main tank oil results, e.g. leaks, tap changer issues, cooling system issues, etc. Further detail in relation to EPRI's study can be found in TSP Section 2.3.

The predominant indicator of transformer condition is insulation deterioration, which occurs as a function of time and operating temperature, and is irreversible. Power transformer insulation consists of both oil and cellulose (paper/pressboard) that degrade over time. 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.

Transformer condition can be impacted by several factors including loading history, age, environmental condition and history of outages or other issues. If a deteriorated transformer is carrying a higher load, it is likely to deteriorate faster than if it carries a lower load. A transformer's load can depend on a station design, and it may temporarily have a higher load if it is carrying the load of another transformer that is currently experiencing an outage. In a forced outage at a station with two transformers, the remaining transformer that did not fail (which is likely the same age and has been subjected to similar environmental exposures and loading as the failed unit) would be required to bear the full load and thus undergo further condition deterioration as a result.

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. As illustrated in Figure 1 below, assessment of the network station transformer fleet's condition shows that approximately 46 (32%) units are rated poor condition.

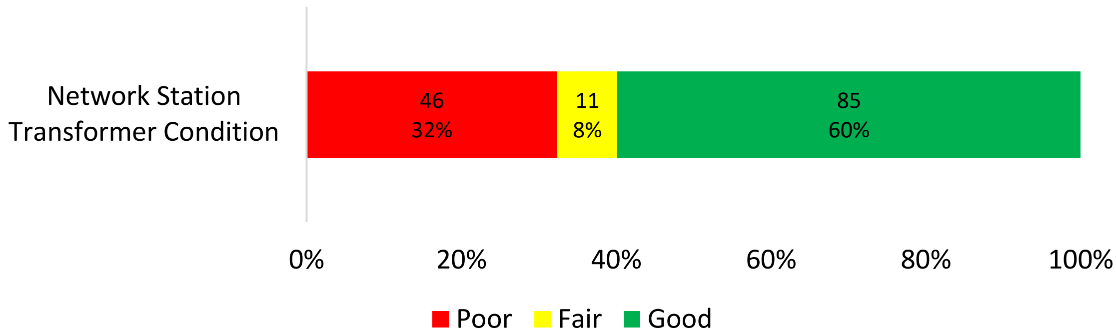

Figure 1: Condition Summary of Network Station Transformer Fleet

Breaker Condition – Network stations

Similar to transformers, breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages to 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 the major driver for breaker replacement as part of the Investment.

As discussed in TSP Section 2.2., circuit breakers use a variety of interrupting mediums including oil, air and SF6 gas. In the case of air and SF6, 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 SF6 gas to leak out and lower the breaker's pressure. Concurrently, leaks create a path for moisture ingress. Either condition (lower pressure or moisture ingress) reduces 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.

A large number of the breakers in Hydro One's fleet contain PCBs. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements to meet the PCB Regulation requirements.

Some of Hydro One's breakers (approximately 143, or 3% of the overall fleet) are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to some first generation SF6 GIS circuit breakers and most types of oil circuit breakers. Where parts are difficult to procure, specific units are replaced so the decommissioned devices can serve as strategic spares for the remaining in-service fleet, but that is not feasible for approximately 3% of the overall fleet.

Similar to transformers, operating a large percentage of the fleet that is 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 140 (10%) are rated poor condition, as illustrated in Figure 2: Condition Summary of HV Breaker FleetFigure 2. Another 307 (22%) of network station breakers are in fair condition, exhibiting some form of deterioration.

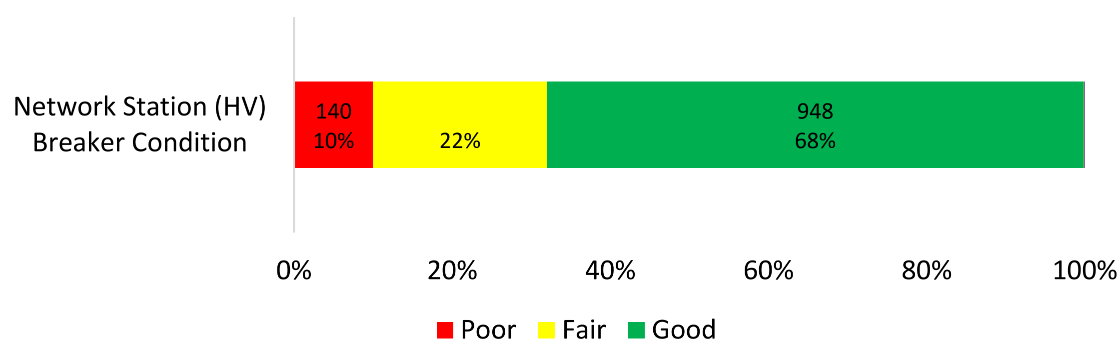

Figure 2: Condition Summary of HV Breaker Fleet

Hydro One's approach with respect to the replacement of breakers is to target specific breakers that are in poor condition which includes obsolescence as a result of limited or no vendor support for aged product lines. 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 • PCB regulatory compliance • 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 • 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

Hydro One's plan prioritizes breaker replacements based on poor condition, obsolescence, vendor support availability, environmental footprint, system criticality and safety risk.

To assess the changes in short circuit levels due to system upgrades and new or modified customer connection facilities, Hydro One performs project-specific short circuit studies and identifies any required breaker upgrades 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.

Replacing breakers that are based on obsolete technology eliminates maintenance activities that are no longer required for modern breakers. Examples include the elimination of ABCBs and the replacement of pneumatic mechanisms with simpler mechanisms.

Where spare parts are difficult to obtain or are no longer commercially available, sustainment of associated breaker fleets will be achieved by harvesting subcomponents from decommissioned units until the remaining fleet can be replaced. Where breakers exhibit unacceptable performance that cannot be resolved with a reasonable level of maintenance, these breakers will be targeted for replacement.

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[1] to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

Protection Equipment Demographics – Network Stations

In contrast to transformers and breakers (which are replaced based on condition of asset components), it is not possible to assess the physical condition of this class of asset and as such, the expected service life (ESL) of protection devices plays an important role in the replacements of protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible nor relevant given the make-up of these electronic or solid state devices. Hydro One also uses other factors 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. in terms of the provision of spare parts and repair services), and the inability to comply with current reliability standards. As such, to prevent the potentially

[1] Canadian Environmental Protection Act, 1999 - PCB Regulations SOR/2008-273.

significant reliability and safety impact of a sudden failure, ESL is a key trigger for further evaluation to confirm replacement needs.

As explained in TSP Section 2.2, approximately 27% of the protection system population is operating beyond its ESL. Furthermore, over 90% of the solid-state fleet is already 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.

As explained in TSP Section 2.1, some protection systems at network stations must also comply with NERC and NPCC reliability standards. These BES stations are equipped with multiple, redundant and robust protection and control systems to ensure that faults are isolated so as to prevent cascading and damage to assets near the fault. In addition, infrastructure relating to key sites and processes is designed to adhere to NERC Critical Infrastructure Protection (CIP) requirements. For example, sites subject to NERC and/or NPCC requirements require additional equipment, such as protection systems and station battery systems, and must meet additional CIP requirements, such as physical and electronic/cyber-security to prevent unauthorized network access. When replacing assets to address condition-related risk or system requirements, investments may be required to make upgrades where a like-for-like replacement does not match current standards.

Without investments, critical assets at network stations will continue to degrade and the number of assets in poor condition will continue to increase, thereby resulting in increased risk of unexpected failures.

C. INVESTMENT DESCRIPTION

As discussed above, the 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 bundled approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and may be accompanied by some level of electrical re-configuration to address operating concerns and customer preferences or to standardize the installed equipment. In the case where there are relatively few assets identified at a particular station for replacement (e.g. one of the key station asset and accompanying ancillary equipment or a small subset of the minor station assets), this station is identified as a candidate for a particular asset-focused replacement project, as described in ISD-SR-09 and/or ISD-SR-10.

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 2023-2027 period, the Investment targets 30 stations and addresses the replacement of 35 transformers (22 to be in-serviced during the 2023-2027 period), 154 breakers (93 to be in-serviced during the 2023-2027 period), and 753 protection systems (523 to be in-serviced during the 2023-2027 period). While Hydro One has a significant number of transmission station assets that are in poor condition, the pacing of the Investment does not target all of them. The 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 more detailed list of assets planned for replacement is presented in **Appendix "A"** below.

Hydro One also performs functional reconfiguration 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, 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 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 further discussed in SPF Section 1.6 and 1.7, and TSP Section 2.7) 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.

D. 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 (MOECP) in regard to oil spills, NERC and NPCC requirements; maintain long-term bulk system reliability; eliminate operational concerns through reconfiguration; maintain long-term bulk system reliability; reduce constraints on generation resources.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 2 - 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
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within a station as part of the same investment. • Efficiencies in design, construction, commissioning and outages by addressing multiple assets within a station in one investment

E. 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 projected spending on the aggregate investment level.

Table 3 – Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Capital and Minor Fixed Assets	167.6	216.0	205.8	219.7	163.0	222.5	92.1	1,286.6
Less Removals	4.6	6.5	6.2	6.1	4.6	9.4	3.3	40.8
Gross Investment Cost	163.0	209.4	199.6	213.6	158.4	213.1	88.8	1,245.8
Less Capital Contributions	1.2	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Net Investment Cost	161.8	209.4	199.6	213.6	158.4	213.1	88.8	1,244.6

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 MOECP 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
  - The more complex the project, the more inter-connections, and the more outages required will increase the cost of the project.
- 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.

F. ALTERNATIVES

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 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 PROGRAMMATIC REPLACEMENT OF COMPONENTS (UNBUNDLED)

Planned Replacement of Components (Unbundled) alternative involves replacing individual station components in poor condition. This alternative is viable only when a single component at a transmission station has deteriorated, as described in T-SR-09 and/or T-SR-10. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. In this case, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that an integrated station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

ALTERNATIVE 3: BUNDLED INTEGRATED REPLACEMENT OF COMPONENTS

Bundled Replacement of Components at network stations is the preferred investment option. This integrated approach addresses the needs identified at the network transmission station to maintain reliability for Hydro One's transmission system in the most cost effective and efficient manner. Hydro One can refurbish entire stations that have a significant population of assets in poor condition, before failures occur. Furthermore, for transmission stations that have a significant population of deteriorated, poor condition assets and where operational concerns could be mitigated or eliminated through reconfiguration, station refurbishment is the best alternative as it enables a holistic assessment of asset and operational needs which are consolidated into a single integrated investment. Bundling the replacement of transmission station components also reduces the number and duration of planned outages affecting customers connected to the station. For example, if a circuit breaker disconnect switch is replaced together with the circuit breaker outages, efficiencies are realized since the grouped equipment that requires an outage is similar for the switch as it is for the breaker. Had the replacements been sequential the outages for the replacements would have to be duplicated, as would the resource requirements to complete the work.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, 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. 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 makes best effort into coordinating with customers.
    - At network stations serving large generation and industrial customers, Hydro One coordinates with planned customer outages or shut downs.

- Real estate requirements
  - Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Procurement challenges
  - Major equipment procurement lead times can be long.
  - Hydro One engaged vendors at appropriate times in the planning process to ensure sufficient lead times to obtain major equipment.

APPENDIX A – DESCRIPTION OF INVESTMENTS

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-01.01	Claireville TS	• This investment involves the replacement of protection systems; AC & DC station service systems; select line terminal assets including surge arresters, air-gas bushings, and instrument transformers; and other minor ancillary assets. • This investment is needed to address obsolete protection systems; critical AC & DC station service systems that are obsolete, difficult to maintain and poorly supported; and line terminal assets that are in poor condition. • This investment is expected to mitigate equipment failure risks and operational risks at this critical station and thereby contribute to maintaining long-term bulk electric system reliability.	0	0	24
T-SR-01.02	Seaforth TS	• This investment involves the replacement of 230-115kV autotransformers, 115-27.6kV power transformers, entire 27.6kV switchyard, select 230kV and 115 line disconnect switches, DC station service and protection and controls equipment. • The investment is needed to address the poor condition and performance of the transformers as confirmed by DGA analysis, on-going cooling system issues, and obsolete style tap-changers; select 27.6kV breakers with maintenance challenges due to asset obsolescence. Consequently the non-standard 70 year old legacy switchyard will be replaced due to work clearance and maintainability challenges; as well as the DC system, P&C and other auxiliary equipment. • The investment is expected to reduce risk of equipment failure and maintain supply reliability to the bulk system and to local area Hydro One distribution and Festival Hydro customers, and eliminate existing maintainability challenges with 27.6kV switchyard that could impact future reliability and performance.	4	7	25
T-SR-01.03	Fort Frances TS	• This investment involves the replacement of 230kV circuit breakers, high voltage switches, AC and DC station service equipment and 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 network system and local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	2	26

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-01.04	Keith TS	• This investment involves the replacement and upsizing of autotransformers, associated disconnect switches, the existing DC station service system and protection relays. • The investment is needed to replace the autotransformers in poor condition and increase supply capacity on the 115kV network by increasing the autotransformer capacity from 115MVA to 250 MVA in line with Regional Planning recommendations. • This investment is expected to reinforce the transmission system in the area, maintain reliability to the bulk system and local customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	17
T-SR-01.05	Whitedog Falls SS	• This investment involves replacement of 115kV breakers, 115kV disconnect switches, and DC battery chargers. • The investment is needed to address equipment that is in poor condition. • This investment is expected to maintain reliability to the local customers and generator facilities; and is not expected to increase capacity. The investment will mitigate the risk of outages and supply interruptions due to asset failure.	0	3	0
T-SR-01.06	Milton SS	• This investment involves the replacement of protection systems; AC & DC station service systems; select line terminal assets including surge arresters, air-gas bushings, and instrument transformers; and other ancillary assets. • This investment is needed to address obsolete protection systems; critical AC & DC station service systems that are obsolete, difficult to maintain and poorly supported; and line terminal assets that are in poor condition. • This investment is expected to mitigate equipment failure risks and operational risks at this critical station and thereby contribute to maintaining long-term bulk electric system reliability.	0	0	13
T-SR-01.07	Rabbit Lake SS	• This investment involves replacement of 115kV breakers, 115kV disconnect switches, instrument transformers, station service transformers, 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. • Due to the lack of space in existing relay building a new PCT building and Automatic Transfer Scheme building is required. This investment is expected to maintain reliability to the bulk network system; and is not expected to increase capacity. The investment will mitigate the risk of outages and supply interruptions due to asset failure.	0	5	20

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			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	17	53
T-SR-01.09	Sarnia Scott TS	• This investment involves the replacement of an autotransformer, associated disconnect switches and protections. • The investment is needed to address assets in poor condition or 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. 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.	1	0	4
T-SR-01.10	Kenora TS	• This investment involves replacement of 230 kV breakers, AC station service and DC station service transfer schemes, AC station service transformers, and protection schemes. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability both the bulk system network and to the local connection network; and is not expected to increase capacity. The investment will mitigate the risk of outages and supply interruptions due to asset failure.	0	5	24
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

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
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
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	0
T-SR-01.14	Middleport TS	• This investment involves the replacement of 500/230 kV, 450/600/750 MVA autotransformer T6 and associated disconnect switches and protection and control equipment at a 50 year old Middleport TS. • This investment is needed to address poor condition and/or obsolete assets at the Middleport TS. This investment is expected to maintain reliability of power delivery to high voltage network.	1	0	6
T-SR-01.15	Porcupine TS	• This investment involves the replacement of autotransformers and associated ancillary assets including spill containment. • This investment is needed to address poor condition of the T8, T3, T4 autotransformer, a significant bulk electric system asset. This investment is expected to mitigate equipment failure risks and operational risks at this critical station and thereby contribute to maintaining long-term bulk electric system reliability.	3	0	31

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-01.16	Essa TS	• This investment involves the replacement of three single-phase 500/230kV autotransformers units, station service transformer, disconnect switches, a breaker, the oil water separator system, and the AC station service system. • This investment involves the replacement of equipment that is in poor condition or is 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.	1	1	4
T-SR-01.17	Mackenzie TS	• This investment involves replacement of a 230kV/115 kV autotransformer, 230kV breakers, disconnect switches, instrument transformers, station service transformers, AC & DC station service transfer scheme and Protection, Control and Telecom relays. • This investment is needed to address equipment that is in poor condition or is obsolete. • In addition, a new 115kV/44kV load connection facility is needed to supply a customer relocating their connection from Moose Lake TS to Mackenzie TS. • The new load supply facility to include 115kV stepdown transformers, 115kV and 44kV breakers, and the necessary protection, control and telecom equipment. This investment is expected to maintain reliability to the bulk network system and local customers; and is not expected to increase capacity. The investment will mitigate the risk of outages and supply interruptions due to asset failure.	1	4	36
T-SR-01.18	Algoma TS	• This investment involves the replacement of 115kV circuit breakers, disconnect switches, station service transformers, 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 will maintain the reliability of supply between northern and southern Ontario	0	3	37
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

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
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	16
T-SR-01.21	Ansonville TS	• This investment involves replacement of protection relays, Instrument transformers, surge arrestors and DC and AC station service components. • The 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 expected to increase existing system capacity. 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.	0	0	18
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	48
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.	1	6	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	22	58

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
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
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 equipment failure and maintain supply reliability to Hydro One distribution customers in the Lennox/Napanee area.	1	0	25
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	25
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.	2	5	14
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	0

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-01.30	Mississagi TS	• This investment involves the replacement of 230kV breaker, 230kV switches, 230kV instrument transformer, AC and DC station service systems and protection, control and telecom relays. • The investment is needed to address assets in poor condition or 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.	0	7	30
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	111
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	5	17
T-SR-01.33	Claireville TS	• This investment involves the replacement of 500kV GIS breakers. Each breaker includes six interrupters. • The investment is needed because the GIS breaker equipment has been discontinued. • The investment is expected to maintain existing bulk 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.	0	36	0

ISD Ref.	Station	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	**Brkr**	**Prot**
T-SR-01.34	Beck 2	• The investment involves the replacement of a regulating transformer, associated surge arrestors and disconnect switches. • This investment is needed to address equipment that is in poor condition. • 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.	1	0	0
T-SR-01.35	Claireville TS	• This investment involves the replacement of the T13 autotransformer and associated ancillary assets including spill containment. • This investment is needed to address the poor condition of the T13 autotransformer, a significant bulk electric system asset. This investment is expected to mitigate equipment failure risks and operational risks at this critical station and thereby contribute to maintaining long-term bulk electric system reliability.	1	0	0
	Total		**35**	**154**	**753**

APPENDIX B – DETAILED INVESTMENT COSTS

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 2.10. 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 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.

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	2024	2025	2026	2027	23-27 Total	Proj. Total	
T-SR-01.01	Claireville TS	SR-04	E	8.6	0.0	0.0	0.0	0.0	8.6	21.7	2023
T-SR-01.02	Seaforth TS	SR-03	P	20.1	0.0	0.0	0.0	0.0	20.1	54.4	2023
T-SR-01.03	Fort Frances TS	SR-03	P	11.9	0.0	0.0	0.0	0.0	11.9	20.1	2023
T-SR-01.04	Keith TS	SR-03	E	11.0	0.0	0.0	0.0	0.0	11.0	36.5	2023
T-SR-01.05	Whitedog Falls SS	-	P	3.7	0.0	0.0	0.0	0.0	3.7	8.1	2023
T-SR-01.06	Milton SS	SR-04	P	12.6	0.0	0.0	0.0	0.0	12.6	19.2	2023
T-SR-01.07	Rabbit Lake SS	SR-04	P	11.0	0.0	0.0	0.0	0.0	11.0	23.1	2023
T-SR-01.08	Lakehead TS	SR-04	P	10.7	10.4	0.5	0.0	0.0	21.6	36.1	2024
T-SR-01.09	Sarnia Scott TS	SR-03	P	16.0	5.4	0.0	0.0	0.0	21.4	26.4	2024
T-SR-01.10	Kenora TS	SR-04	P	5.5	5.8	2.4	0.0	0.0	13.7	15.9	2025
T-SR-01.11	Marathon TS	SR-04	P	5.3	5.6	0.7	0.0	0.0	11.6	14.7	2025
T-SR-01.12	Wawa TS	SR-02	P	9.2	14.3	13.1	0.0	0.0	36.6	44.8	2025
T-SR-01.13	Lakehead TS	-	P	9.7	9.7	4.9	0.0	0.0	24.2	29.1	2025
T-SR-01.14	Middleport TS	SR-03	P	5.4	14.9	8.8	0.0	0.0	29.2	29.8	2025

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	**2024**	**2025**	**2026**	**2027**	**23-27 Total**	**Proj. Total**	
T-SR-01.15	Porcupine TS	SR-03	P	21.0	25.3	25.2	0.0	0.0	71.6	77.7	2025
T-SR-01.16	Essa TS	-	P	4.8	15.5	15.5	0.0	0.0	35.8	36.6	2025
T-SR-01.17	Mackenzie TS	SR-04	P	14.6	16.5	15.5	0.0	0.0	46.6	51.4	2025
T-SR-01.18	Algoma TS	SR-03	P	4.6	11.5	9.6	2.9	0.0	28.6	30.0	2026
T-SR-01.19	Des Joachims TS	-	P	0.2	0.8	2.6	3.1	0.0	6.7	6.7	2026
T-SR-01.20	Otto Holden TS	SR-03	P	7.5	20.4	25.2	8.2	0.0	61.4	65.3	2026
T-SR-01.21	Ansonville TS	-	P	0.5	0.6	2.9	3.5	1.2	8.7	8.7	2027
T-SR-01.22	Manby TS	SR-03	P	5.4	9.1	13.5	12.1	11.5	51.7	52.5	2027
T-SR-01.23	Fort Frances TS	-	P	0.3	0.8	2.6	10.5	6.4	20.6	20.6	2027
T-SR-01.24	Merivale TS	SR-04	P	4.9	18.4	39.8	41.7	63.1	167.8	168.4	2027
T-SR-01.25	Beach TS	SR-03	P	4.1	9.8	15.8	9.4	5.3	44.4	45.3	2028
T-SR-01.26	Lennox TS	-	P	0.2	0.6	2.4	14.5	13.6	31.4	34.4	2028
T-SR-01.27	Buchanan TS	SR-03	P	0.2	0.6	2.0	12.5	17.6	32.8	39.8	2028
T-SR-01.28	Owen Sound TS	SR-06	P	0.0	0.6	1.1	6.7	13.2	21.6	28.1	2028
T-SR-01.29	Kenora TS	-	P	0.0	0.5	0.6	2.4	7.3	10.8	15.0	2028
T-SR-01.30	Mississagi TS	SR-04	P	0.0	0.5	0.7	4.2	16.7	22.1	32.4	2028
T-SR-01.31	Hawthorne TS	-	P	0.3	0.6	3.3	9.9	13.1	27.1	33.7	2028
T-SR-01.32	Cataraqui TS	-	P	0.3	0.6	2.9	8.9	12.2	24.9	31.1	2028
T-SR-01.33	Claireville TS	-	P	0.0	0.2	0.6	4.0	17.2	22.0	49.2	2029
T-SR-01.34	Beck 2 TS	-	P	0.0	0.2	0.6	1.8	6.8	9.4	16.7	2029
T-SR-01.35	Claireville TS	-	P	0.0	0.3	0.5	2.0	8.1	11.0	21.1	2029
	Net Investment Cost			**209.4**	**199.6**	**213.6**	**158.4**	**213.1**	**994.1**	**1244.6**	

Witness: REINMULLER Robert

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T-SR-02	**TRANSMISSION STATION RENEWAL - AIR BLAST CIRCUIT BREAKERS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	172.3	153.8	115.8	99.3	34.4	575.6

Summary:

This investment involves the replacement of all Air Blast Circuit Breakers (ABCBs) at Hydro One's transmission stations due to asset's poor condition, obsolescence and poor performance. The primary trigger for the investment is significant reliability risk and high operation and maintenance costs. The investment is expected to increase reliability performance, reduce operation and maintenance costs, and decrease unplanned outages within major bulk transmission stations.

A. OVERVIEW

The Air Blast Circuit Breaker Replacement investment (the "Investment") involves the replacement of ABCBs and their auxiliary station equipment that are at a high risk of failure due to their deteriorated condition and obsolescence. The principal drivers of the Investment are 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 due to asset obsolescence. The majority of installed ABCBs are in poor condition. In addition to being in poor condition, the obsolescence of ABCBs, which were originally installed in the 1970s, pose 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.

Almost half of Hydro One's ABCBs population is 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. There are seven generators connected through Hydro One's network stations with ABCBs with the total output of 13,707 MW of clean nuclear and hydro power generation. 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. As further described in SPF Section 1.6, high level of reliability is of utmost importance to these customers' operations.

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. The projected cost of the Investment is estimated to be $575.6M over the 2023-2027 test period.

B. NEED AND OUTCOME

B.1 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 is installed at critical transmission network stations that 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. Table 1 below shows generation capacity of all stations that are currently equipped with ABCBs.

Table 1 - Generators connected through Hydro One stations with ABCBs

Hydro One Station	Connected Generator(s)	Generator Capacity (MW)
Bruce A TS	Bruce A GS	3,116
Bruce B SS	Bruce B GS	3,268
Cherrywood TS	Pickering GS	3,100
Lennox TS	Lennox GS	2,100
Sir Adam Beck I SS	Sir Adam Beck I GS	450
Sir Adam Beck II TS	Sir Adam Beck II GS	1,499
	Sir Adam Beck Pump GS	174
	Total	**13,707**

As of December 2020, 177 HV and 5 MV ABCBs have been replaced as a result of various control components 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 these Air Blast Circuit Breakers with standard SF6 breakers will reduce the maintenance cost for each replaced breaker.

The high pressure air system is highly susceptible to air leaks that cause outages. Severe air leaks are a significant concern for the ABCB fleet as large groupings of breakers are supplied by a common airline. In the winter months, issues with air pressure and safety valves freezing in the open position lead to the loss of air and the loss of breaker control. This can result in the removal or isolation of multiple adjacent breakers and HV circuits, thereby causing large load interruptions and generation bottling. For example, in winter 2017, after experiencing pressure loss on the air system due to low temperatures, multiple HV breakers were forced out of service at Cherrywood TS in the 230kV switchyard, thereby constraining generation capacity and power flow throughput.

The average age of the ABCBs population installed on Hydro One's transmission system is 49.5 years, surpassing the manufacturer's specified service life of 40 years. As part of the asset condition assessment, Hydro One confirmed that the entire population of ABCBs is in poor condition. This assessment is based on the factors such as internal condition diagnostics, performance, criticality, obsolescence and economics. Hydro One performs internal condition diagnostics (Level 1 and Level 2 diagnostic testing) where it gains condition data on the breakers via micro-ohm measurement and timing tests. In accordance with Hydro One performance records, ABCBs are the poorest performing breaker population in Hydro One's transmission system. Circuit breaker performance is measured by assessing the number of forced outages due to some inherent failure of the breaker itself. A "forced outage" is the automatic or forced manual removal of HV breakers caused directly by the breaker itself or terminal equipment directly adjacent to the breaker. Typical ABCB failure modes have included control components issues, air leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions. As shown in Figure 1 below, up until 2017, the number of forced outages due to ABCB failure had been significantly increasing due to known air system issues caused by deteriorated O-rings, valves and problems with control components. As Hydro One started replacing the poor condition assets, the ABCB-related outages started to decrease, demonstrating that Hydro One's strategy is succesfull. Nevertheless, there is still a number of obsolete, poor condition ABCBs in Hydro One's breaker fleet that require replacement.

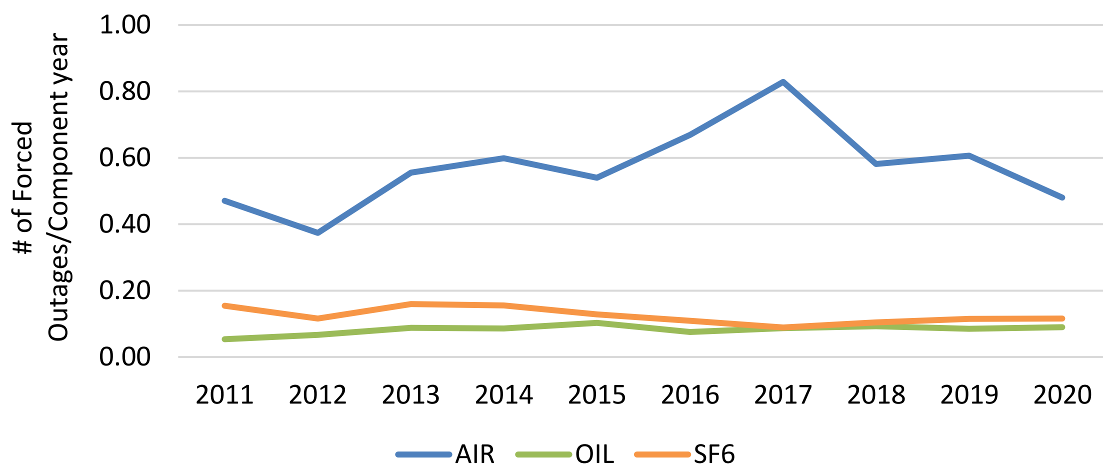

Figure 1: Circuit Breaker Forced Outage Duration by Breaker Type

As shown in Table 1 above, poor condition ABCBs are installed at critical transmission network stations that support nuclear and hydraulic generation plants with the total output of 13,707 MW of clean nuclear and hydro power generation that then gets delivered to major load centers, such as the City of Toronto and the Greater Toronto Area. These transmission stations also connect international power flow to the states of New York and Michigan. Any forced outages at these critical stations, attributed to ABCBs, may have a significant adverse impact on customers and overall integrity of provincial power flow. 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. For example, in 2016, Sir Adam Beck II had a loss of 6 ABCBs which resulted in 100 MW of reduced generation, impacting the imports and exports of power to the New York Power Authority and Hydro One's customer, and Ontario Power Generation had to redirect the river water flow to avoid flooding parts of downtown Niagara Falls.

Further, transmission network stations with ABCBs are required to comply with various mandatory regulations for transmission reliability, including mandatory standards and directories established by the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC) and the IESO, which are international, regional and Ontario reliability regulatory authorities, respectively, involved in regulating, promoting and improving the reliability of transmission networks in North America. Such for example, section 5.7 of the IESO's Ontario Power System Restoration Plan (OPSRP) requires the IESO and the restoration participants, such as Hydro One, to restore the power system and mitigate the emergency in the event of a partial or complete blackout. The majority of the bulk stations listed in OPSRP are still operating through ABCBs. As such, Hydro One is required, pursuant to section 5.7.3 of the OPSRP, to pre-determine the air system's ability to support multiple breaker operations, adopt operating procedures to monitor for problems and to mitigate any identified shortfalls in capability.

High costs and difficulties associated with maintenance requirements (compared to newer technology), the unavailability of spare parts due to obsolescence, and the lack of technical support to work on the deteriorating population of installed ABCBs lead to longer outage times associated with both routine and emergency maintenance. This puts constraints on Hydro One to ensure its transmission system performs in compliance with all regulatory requirements and meet the high expectations of its customers. As such, continued replacement of ABCBs is required.

C. INVESTMENT DESCRIPTION

The Investment involves a series of individual investments at various transformer stations, as further described in Appendix A below. Each ABCB replacement investment will vary in size and scope and will include some or all of the following: the replacement of ABCBs, removal of the high pressure air system, upgrade AC and DC systems, protection, upgrades to 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. Cumulatively, the Investment targets the replacement of 3 power transformers (all to be in-serviced during the 2023-2027 period), 104 circuit breakers

(101 ABCB, 2 oil breakers and 1 SF6 breaker) (86 to be in-serviced during the 2023-2027 period) and 325 protections (285 to be in-serviced during the 2023-2027 period) at nine transformer stations during the planning period.

D. 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 NERC, NPCC and IESO requirements.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 2 - Outcome Summary

Customer Focus	• 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 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
Financial Performance	• Reduce operating and maintenance costs • Realize cost savings by addressing multiple deteriorating components within the station as part of the same investment

E. EXPENDITURE PLAN

As discussed above, the Investment involves the replacement of ABCBs and their auxiliary station equipment that are at a high risk of failure due to deteriorated condition and asset obsolescence. Hydro One planned the Investment in a way that strives for completion as effectively and efficiently as possible to minimize the cost of performing this sustainment task. As part of this optimization, Hydro One will not only replace the ABCBs, but will replace all other deteriorated assets, upgrade Protection, Control and Telecom equipment to the latest industry standards and improve reliability and operability of the system within each investment.

Table 3 below summarizes historical and projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Capital and Minor Fixed Assets	701.6	180.1	158.9	126.0	107.3	40.6	6.3	1,320.7
Less Removals	18.9	7.8	5.2	5.2	2.9	1.2	0.2	41.4
Gross Investment Cost	**682.7**	**172.3**	**153.8**	**120.8**	**104.3**	**39.4**	**6.1**	**1,279.4**
Less Capital Contributions	0.0	0.0	0.0	5.0	5.0	5.0	0.0	15.0
Net Investment Cost	**682.7**	**172.3**	**153.8**	**115.8**	**99.3**	**34.4**	**6.1**	**1,264.4**

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 - foundation/structural replacements, in-situ or Greenfield replacement. The safety design requirements based on the latest Hydro One standards (i.e. new clearance requirements, Arc Flash requirements, etc.).
- NERC and/or NPCC requirements require 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).
- By-pass construction where needed to minimize customer impacts. In many situations, to avoid constraining generation and power flow, additional by-passes are required; these are costly to install and are typically removed at the end of the investment (the cost of this work may range between $3M and $5M).

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred option.

ALTERNATIVE 1: DO NOTHING

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 500kV, 230kV, and 115kV transmission networks and international tie-line connections by 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, and the air system must be maintained until all ABCBs are replaced. This result would be contrary to the clear preferences of Hydro One's customers.
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 increasing OM&A costs as the frequency of outages increase as presented in TSP Section 2.2.
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 SF6 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

Switchyard Rebuild is based on rebuilding the entire ABCB switchyard in a new location (Greenfield) using modern SF6 breakers instead of replacing only 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. Depending on the situation, the Greenfield solution could be less expensive in congested stations; however often times Greenfield construction will be more costly due to the 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

Planned In-Situ Replacements is the preferred undertaking. This alternative is based on replacing ABCBs and auxiliary systems within the same station footprint using modern SF6 breakers. SF6 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 preferred 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 preferred alternative, unlike the “Do Nothing” alternative, proactively addresses and paces replacements without jeopardizing system reliability and customer supply

points. Unlike Alternative 2, the preferred alternative results in a more cost effective solution since most real-estate and station reconfiguration challenges are avoided.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, 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.

1

APPENDIX A – DESCRIPTION OF INVESTMENTS

ISD Ref.	Station Name	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-02.01	Cherrywood TS	• ABCB breakers at Cherrywood TS are over 48 year 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 address replacement of twelve 230 kV ABCBs and associated switches, 230 kV and 500 kV switchyard AC system upgrade, 230 kV switchyard DC system upgrades, and protection and control system upgrades. • Nine breakers remain to be replaced. Replacing this unit will maintain reliability of power delivery to high voltage network.	0	9	21
T-SR-02.02	Beck #2 TS	• ABCB breakers at Beck TS are over 48 year old and based on the asset condition assessment are determined to be in poor condition. • Consistent with the ABCB breaker replacement strategy, investment will replace twenty 230 kV ABCBs and associated switches, and other poor condition and/or obsolete assets, as well as protection and control system upgrades. • Nine breakers remain to be replaced. Replacing these obsolete breakers will maintain reliability of high voltage NERC and NPCC Bulk Electric System.	0	9	22
T-SR-02.03	Bruce B SS	• ABCB breakers at Bruce B SS are over 45 year 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 the remaining ten 500 kV ABCBs, associated switches, protection and control upgrades and other associated equipment with a new gas insulated switchgear (GIS) station. Replacing these units will maintain reliability of power delivery from a nuclear station and the NERC/NPCC Bulk Electric System.	0	10	30
T-SR-02.04	Cherrywood TS	• ABCB breakers at Cherrywood TS 500kV are over 45 year 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 switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. • Four breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to high voltage network.	0	4	16
T-SR-02.05	Middleport TS	• ABCB breakers at Middleport TS are over 45 year old and based on the asset condition assessment are determined to be in poor condition.	0	14	40

		• Consistent with the ABCB breaker replacement strategy, this investment will replace twenty-one 230 kV ABCBs and associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Fourteen breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to the high voltage network.			
T-SR-02.06	Nanticoke TS	• ABCB breakers at Nanticoke TS are over 45 year 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 eight 500 kV ABCBs and associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Eight breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to high voltage network.	0	8	22
T-SR-02.07	Lennox TS	• ABCB breakers at Lennox TS are over 48 year 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 the ten 230 and six 500 kV ABCBs and associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Twelve breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to the high voltage network.	0	12	42
T-SR-02.08	Beck #1 SS	• ABCB breakers at Nanticoke TS are over 48 year 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 two 115 kV ABCBs and associated switches and other poor condition and/or obsolete, as well as protection and control system upgrades. Two breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to high voltage network.	0	2	48
T-SR-02.09	Bruce A SS	• ABCB breakers at Bruce A 500kV are over 48 year old and based on the asset condition assessment are determined to be in poor condition. The autotransformers are also in poor condition. • Consistent with the ABCB breaker replacement strategy, this investment will replace nine 500 kV ABCBs, one SF6 breaker, three autotransformers at Bruce A 500kV and associated switches and other poor condition and/or obsolete assets, as well as P&C system upgrades with a new GIS station. Ten breakers remain to be replaced. Replacing these units will maintain reliability of power delivery to high voltage network.	3	10	30
T-SR-02.10	Essa TS	• ABCB breakers at Essa TS are over 45 year old and based on the asset condition assessment are determined to be in poor condition.	0	8	14

		• Consistent with the ABCB breaker replacement strategy, this investment will replace six 500 kV ABCBs and associated 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.			
T-SR-02.11	Cherrywood TS	• 230kV ABCB breakers at Cherrywood TS are over 45 year 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 the remaining 230 kV ABCBs and associated switches and other poor condition and/or obsolete assets, as well as protection and control system upgrades. Eighteen breakers remain to be replaced but a number of new installations are pending due to the Pickering shut down plan. Replacing these units will maintain reliability of power delivery to high voltage network.	0	18	40
	Total		**3**	**104**	**325**

APPENDIX B – DETAILED INVESTMENT COSTS

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 2.10. 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 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.

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	2024	2025	2026	2027	23-27 Total	Proj. Total	
T-SR-02.01	Cherrywood TS	SR-01	E	15.4	0.0	0.0	0.0	0.0	15.4	111.6	2023
T-SR-02.02	Beck 2 TS	SR-01	E	11.5	0.0	0.0	0.0	0.0	11.5	128.4	2023
T-SR-02.03	Bruce B SS	SR-01	E	22.3	22.9	0.0	0.0	0.0	45.2	180.2	2024
T-SR-02.04	Cherrywood TS	SR-01	E	17.3	19.7	1.4	0.0	0.0	38.4	74.9	2025
T-SR-02.05	Middleport TS	SR-01	E	9.9	10.2	9.5	0.0	0.0	29.6	119.8	2025
T-SR-02.06	Nanticoke TS	SR-01	E	8.8	8.1	6.4	0.0	0.0	23.3	66.5	2025
T-SR-02.07	Lennox TS	SR-01	E	8.7	9.3	8.8	9.2	0.1	36.0	142.5	2026
T-SR-02.08	Beck 1 SS	SR-01	E	4.6	0.0	0.0	0.0	0.0	4.6	31.8	2026

Witness: REINMULLER Robert

T-SR-02.09	Bruce A TS	SR-01	P	51.8	54.5	52.2	54.9	0.1	213.5	239.5	2027
T-SR-02.10	Essa TS	-	P	12.6	14.7	15.1	15.4	15.2	73.0	77.2	2027
T-SR-02.11	Cherrywood TS	-	P	9.3	14.5	22.4	19.8	19.0	85.0	92.1	2028
	Total			**172.3**	**153.8**	**115.8**	**99.3**	**34.4**	**575.6**	**1264.4**	

T-SR-03	TRANSMISSION STATION RENEWAL - CONNECTION STATIONS
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	334.5	357.7	350.1	406.5	428.6	1,877.3

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.

A. 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. The Transmission Station Renewal – Connection Stations investment (the "Investment") manages asset-failure related risks to stations performance and operational effectiveness with the replacement of key station assets that have been verified to be in poor condition. The Investment involves a series of individual investments and includes the replacement of multiple assets within a particular station. The scope of each investment comprising the Investment includes 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 are provided in **Appendix "A"** below.

Since 2014, Hydro One successfully utilized an integrated approach to station asset management where prudent. In particular, the integrated approach allows Hydro One to replace multiple key transmission assets, such as transformer, breakers, switchgear and protection and control equipment, within a transmission station that have been confirmed through condition assessment to be in poor condition. The integrated approach is primarily driven by the complexities of transmission stations, outage scheduling and the extended lead timelines required to replace deteriorated assets. By employing the integrated approach, Hydro One can complete the necessary asset replacements at a particular station at once as opposed to requiring multiple visits to replace individual assets which would result in re-engineering, repeated construction mobilization, and increased planned outages coordination at the same work location within a small time period. In a lot of instances, initiating multiple projects at a single station is simply not feasible. When transmission stations are reviewed and analyzed by transmission planners, there is an opportunity to review transmission stations for operational improvements and station right sizing for customers. This approach allows Hydro One to consult with customers to ensure refurbished transmission stations meet the needs of Hydro One customers. Examples include connection stations being rebuilt at a different supply voltage to support LDCs future plans or changing the number of transformers in the transmission station due to changes in customer needs.

Within each connection station, there are 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 the transmission station assets, customer equipment, and reduce outages, (iii) switchgear that facilitates the distribution of power to the downstream distribution network. Critical transmission station assets degrade over time. Hydro One does not run its transmission station 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. Once an asset is confirmed to be in poor condition, replacement options are assessed.

Hydro One’s connection stations provide the electrical energy necessary to power the provincial economy and meet society’s daily needs. The main customers served at connection stations are LDCs and large industrial customers. The LDCs, in turn, serve Ontario’s residential, commercial, institutional and small industrial end-users. Hydro One actively works with these customers LDC and large industrial customers to understand their needs and preferences. Through customer engagement activities, Hydro One’s customers expressed strong support for the replacement of aging and deteriorating transmission station assets in order to maintain the overall health of transmission system.

To mitigate risks associated with poor condition assets, Hydro One evaluated several alternatives, as further described below, and concluded that continued targeted replacement of poor condition connection station assets is the most prudent alternative. To optimize the amount of risk mitigated in the pacing of investments, Hydro One prioritizes investments based on asset demographics, condition, performance, environmental and safety concerns, customers, and load served.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

The Investment focuses on the replacement of multiple transmission station assets that facilitate power transformation from a high transmission voltage to a lower distribution voltage. The Investment utilizes a bundled approach that targets multiple assets within a connection station confirmed to be in poor condition. Operating assets that are in poor condition pose an increased risk of failure or risk of failing to execute operations as intended. Transformers may catch fire resulting in 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 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 as well as constrain embedded generation on the distribution network connected to a connection 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, as discussed in Section 2.2, even when there is no 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 cancellation or rescheduling of planned outages for maintenance and replacement work. Furthermore, 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.

Leaving poor condition transmission station assets in-service, such as oil-filled transformers, oil-filled circuit breakers and gas-filled circuit breakers, increases environmental and safety risks. Environmental risks include oil leaks and gas leaks. As transformers and circuit breakers age and deteriorate in condition, one issue that can materialize is oil and gas leaks. Deterioration of gasket and O-rings results in oil leaks from oil-filled transformers and circuit breakers and in gas leaks from SF6 gas-filled circuit breakers. When transformers and breakers are replaced, Hydro One follows the latest environmental standards to ensure oil leaks will be contained. 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. Oil-filled equipment may explode resulting in fires, which may further damage surrounding equipment and injure personnel.

An example of a catastrophic failure is the 2018 Finch T2 catastrophic failure that resulted in three days of fires, within the connection station, before being declared extinguished. As a result of the firefighting effort, transformer oil mixed with water was discharged into the environment. Hydro One environmental staff and emergency spill response were required to manage the oil spill and complete the oil clean-up. The failure event ultimately affected the entire connection station and resulted in six multi-circuit delivery point interruptions with a total interruption duration of one and half days (i.e. 2,234 minutes).

The condition of transformers, breakers, and the age of protection and control systems are the leading indicators of the assets' performance that may eventually lead to catastrophic events, 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 start migrating to the poor condition category, as the deterioration is not reversible. Key station assets demographics and condition are further described below.

TRANSFORMER CONDITION – CONNECTION STATIONS

As discussed in Section 2.2, transformer condition is a leading indicator of performance and a main driver for replacement. Where feasible, Hydro One maximizes the life of poor condition transformers by undertaking certain remedial actions. However, this solution is temporary in nature and requires ongoing monitoring. Based on Hydro One's experience, these transformers will have to be replaced in the near future.

Transformer condition is determined by industry standard diagnostic testing which includes routine transformer oil testing and other maintenance examinations. Hydro One retained a third party expert, EPRI, to provide an independent assessment of the condition of the transformers that Hydro One determined to be in poor condition. EPRI used its PTX Software to examine the condition of the transformer's main tank insulating oil condition. EPRI's analysis confirmed the degraded condition of most of these poor condition transformers. There are also transformers that EPRI was not able to validate based on main tank oil sampling because Hydro One primarily selected those transformers for replacement based on factors other than main tank oil results, e.g. leaks, tap changer issues, cooling system issues, etc. Further detail in relation to EPRI's study can be found in TSP Section 2.3.

The predominant indicator of transformer condition is insulation deterioration, which occurs as a function of time and operating temperature and is irreversible. Power transformer insulation consists of both oil and cellulose (paper/pressboard) that degrade over time. 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.

Transformer condition can be impacted by several factors including loading history, age, environmental condition and history of outages or other issues. If a deteriorated transformer is carrying a higher load, it is likely to deteriorate faster than if it carries a lower load. A transformer's load can depend on a station design, and it may temporarily have a higher load if it is carrying the load of another transformer that is currently experiencing an outage. In a forced outage at a station with two transformers, the remaining transformer (which is likely the same age and has been subjected to similar environmental exposures and loading as the failed unit) would be required to bear the full load and thus undergo further condition deterioration as a result.

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. As illustrated in Figure 1 below, assessment of the connection station transformer fleet's condition results shows that approximately 152 units (26%) are rated poor condition. There are another 63 units (11%) in fair condition that exhibit some form of deterioration. Given that deterioration cannot be stopped or reversed, this population of transformers will start migrating to the poor condition category.

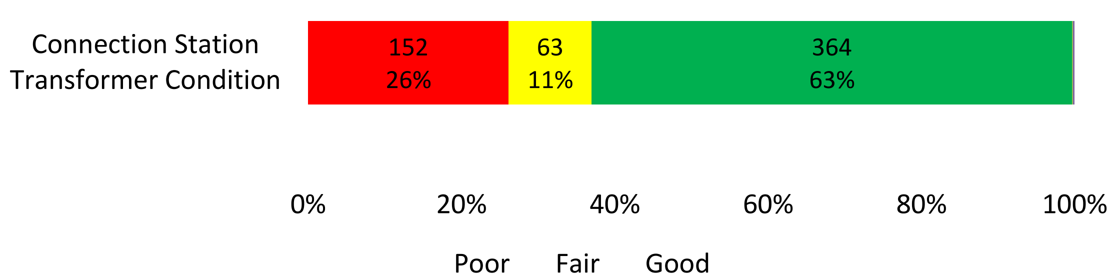

Figure 1: Condition Summary of Connection Station Transformer Fleet

BREAKER CONDITION – CONNECTION STATIONS

Similar to transformers, breaker condition is a leading indicator of expected performance. Poor condition breakers can ultimately result in outages to 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, circuit breakers use a variety of interrupting mediums including oil, air and SF6 gas. In the case of air and SF6, 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 SF6 gas to leak out and lower the breaker's pressure. Concurrently, leaks create a path for moisture ingress. Either condition (lower pressure or moisture ingress) reduces 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.

A large number of the breakers in Hydro One's fleet contain PCBs. As of December 2020, 420 breakers that were manufactured pre-1985 require PCB remediation work including bushing retro-filling (i.e., putting in new PCB free oil to lower the PCB ppm concentration) or replacements to meet the PCB Regulation requirements.

SF_6 is a common and effective dielectric medium used in a large portion of the breaker fleet. Some model types have known issues with leaks, for example the medium voltage SP breakers (there are a total of 208 SP breakers in the Hydro One fleet). SP breakers have a known leak point on the bushing flange for which there is a repair procedure, but there is a subset of the SP breaker population (about 5% identified so far) for which these repairs are not effective, thereby requiring replacement.

Some of Hydro One's breakers (approximately 143, or 3% of the overall fleet) are no longer supported by vendors and aftermarket parts are no longer available or are costly to acquire or fabricate. This is a significant risk factor to some first generation SF6 GIS circuit breakers and most types of oil circuit breakers. Where parts are difficult to procure, specific units are replaced so the decommissioned devices can serve as strategic spares for the remaining in-service fleet, but that is not feasible for approximately 3% of the overall fleet.

Similar to transformers, operating a large number of the circuit breaker fleet that is poor condition increases system reliability risk as this equipment tends to have a worse performance and higher probability of failure. The assessment of the connection station breakers condition shows that approximately 401 (11%) are rated poor condition, as illustrated in Figure 3. Another 1203 (36%) of connection station breakers are in fair condition, exhibiting some form of deterioration.

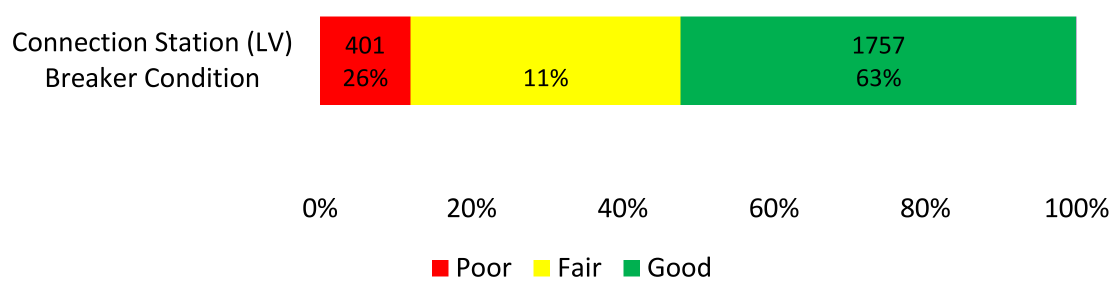

Figure 2: Condition Summary of MV Breakers Fleet

Hydro One's approach with respect to the replacement of breakers is to target specific breakers based on poor condition that pose system risks, as well as to steadily pace investments driven by obsolescence caused by reduced vendor support for aged product lines.

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 • PCB regulatory compliance • 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 • 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

Hydro One’s plan prioritizes breaker replacements based on poor condition, obsolescence, vendor support availability, environmental footprint, system criticality and safety risk.

To assess the changes in short circuit levels due to system upgrades and new or modified customer connection facilities, Hydro One performs project-specific short circuit studies and identifies any required breaker upgrades as part of the IESO Connection Assessment and Approval (CAA) process. Where short circuit level ratings are exceeded, breakers need to be upgraded to higher short circuit rating, since operating beyond the nameplate rating can cause the breaker to fail.

Replacing breakers that are based on obsolete technology eliminates maintenance activities that are no longer required for modern breakers. Examples include the elimination of ABCBs and the replacement of pneumatic mechanisms with simpler mechanisms.

Where spare parts are difficult to obtain or are no longer commercially available, sustainment of associated breaker fleets will be achieved by harvesting subcomponents from decommissioned units until the remaining fleet can be replaced. Where breakers exhibit unacceptable performance that cannot be resolved with a reasonable level of maintenance, these breakers will be targeted for replacement.

Bushings from oil circuit breakers need to undergo oil retro-fill or replacement in order to satisfy federal PCB regulatory requirements[1] to remove equipment containing concentrations of PCB greater than 50 ppm from service by 2025. All transmission station oil-filled equipment manufactured prior to 1985 are expected to be sampled by the end of 2022, so that the PCB contained in such equipment can be removed or retro-filled to less than 50 ppm by the end of 2025.

PROTECTION EQUIPMENT DEMOGRAPHICS – CONNECTION STATIONS

In contrast to transformers and breakers (which are replaced based on condition of asset components), it is not possible to assess the physical condition of this class of asset and as such, the expected service life (ESL) of protection devices plays an important role in the replacements of protection relays. This is because assessment for physical breakdown or loss of strength over time is not feasible nor relevant given the make-up of these electronic or solid state devices. Hydro One also uses other factors 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. in terms of the provision of spare parts and repair services), and the inability to comply with current reliability standards. As such, to prevent the potentially

[1] Canadian Environmental Protection Act, 1999 - PCB Regulations SOR/2008-273.

significant reliability and safety impact of a sudden failure, ESL is a key trigger for further evaluation to confirm replacement needs.

As explained in TSP Section 2.2, approximately 27% of the protection system population is operating beyond its ESL. Furthermore, over 90% of the solid-state fleet is already 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.

Without investments, critical assets at connection stations will continue to degrade and the number of assets in poor condition will continue to increase, thereby resulting in increased risk of unexpected failures.

C. 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 transmission voltage. This bundled approach focuses on a particular station where multiple key station assets require replacement, as driven by their condition, and may be accompanied by some level of electrical re-configuration to address operating concerns and customer preferences or to standardize the installed equipment. In the case where there are relatively few assets identified at a particular station for replacement (e.g. one of the key station asset and accompanying ancillary equipment or a small subset of the minor station assets), this station is identified as a candidate for a particular asset-focused replacement project, as further described in ISD-SR-09 and ISD-SR-10.

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 2023-2027 period, the Investment targets 93 stations and addresses the replacement of 151 transformers (93 to be in-serviced during the 2023-2027 period), 609 breakers (365 to be in-serviced during the 2023-2027 period), and 1570 protection systems (922 to be in-serviced during the 2023-2027 period). While Hydro One has a significant number of transmission station assets that are in poor condition, the pacing of the Investment does not target all of them. The 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 more detailed list of assets planned for replacement is presented in **Appendix "A"** below.

Hydro One also performs functional reconfiguration 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, 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 will remove 5 transformers and 5 breakers from service to account for functional reconfiguration.

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. 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 further discussed in SPF Section 1.6 and 1.7, and TSP Section 2.7) as their preferred option for replacing transmission station assets in poor condition. In regard to replacing aging transmission stations, Hydro One's customers expressed strong 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.

D. 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 (MOECP) in regard to oil spills; maintain long-term reliability of the connection stations; eliminate operational concerns through reconfiguration; and reduce constraints on generation resources.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's:

Table 2 - Outcomes Summary

Customer Focus	• Maintain reliable power delivery at connection stations.
Operational Effectiveness	• Improve the operational effectiveness of connection stations through reconfiguration and standardization of new equipment and design.
Public Policy Responsiveness	• Ensure compliance with applicable regulatory requirements.
Financial Performance	• Realize cost savings by addressing multiple deteriorated assets within a station as part of the same investment. • Efficiencies in design, construction, commissioning and outages by addressing multiple assets within a station in one investment.

E. 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 projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Capital and Minor Fixed Assets	381.6	347.4	368.9	363.1	423.8	441.9	313.2	2,640.0
Less Removals	11.7	10.4	11.2	13.0	17.4	13.4	13.8	90.9
Gross Investment Cost	**369.8**	**337.1**	**357.7**	**350.1**	**406.5**	**428.6**	**299.4**	**2,549.1**
Less Capital Contributions	12.0	2.6	0.0	0.0	0.0	0.0	0.0	14.6
Net Investment Cost	**357.9**	**334.5**	**357.7**	**350.1**	**406.5**	**428.6**	**299.4**	**2,534.6**

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 MOECP, 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
  - The more complex the project, the more inter-connections, and the more outages required will increase the cost of the project.

- Whether the Project 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.

F. 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 PROGRAMMATIC REPLACEMENT OF COMPONENTS (UNBUNDLED)

Planned Replacement of Components (Unbundled) alternative involves replacing individual station components in poor condition. This alternative is viable only when a single key component at a transmission station has deteriorated, as described in T-SR-09 and/or T-SR-10. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. In this case, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

ALTERNATIVE 3: BUNDLED INTEGRATED REPLACEMENT OF COMPONENTS

Bundled Replacement of Components is the preferred investment option at connection stations. This integrated approach addresses the needs identified at the transmission station to maintain reliability for Hydro One's transmission system in the most cost effective and efficient manner. Hydro One can refurbish entire stations that have a significant population of assets in poor condition, before failures occur. Furthermore, for transmission stations that have a significant population of deteriorated, poor condition assets and where operational concerns could be mitigated or eliminated through reconfiguration, station refurbishment is the best alternative as it enables a holistic assessment of asset and operational needs which are consolidated into a single integrated investment. Bundling the replacement of transmission station components also reduces the number and duration of planned outages affecting customers connected to the station. For example, if a circuit breaker disconnect switch is replaced together with the circuit breaker outages, efficiencies are realized since the grouped equipment that requires an outage is similar for the switch as it is for the breaker. Had the replacements been sequential the outages for the replacements would have to be duplicated, as would the resource requirements to complete the work.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, 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. 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 makes best effort to coordinate with customers
  - At connection facilities serving commercial and industrial customers, Hydro One coordinates with planned customer outages or shut downs.
- Real estate requirements
  - Station expansion and new land may be required when assets cannot be replaced in the same physical location.
- Procurement challenges
  - Major equipment procurement lead times can be long.
  - Hydro One engaged vendors at appropriate times in the planning process to ensure sufficient lead times to obtain major equipment.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

ISD Ref.	Station Name/Circuit	Scope, Need and Outcome	Forecast Replacement Units		
			Trfr	Brkr	Prot
T-SR-03.01	Parry Sound TS	• This investment involves the replacement of 230kV/44 kV transformers, 44kV switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • 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 mitigate the risk of outages and supply interruptions due to asset failure.	2	0	18
T-SR-03.02	Port Colborne TS	• This investment is a complete station refurbishment that will replace all assets including transformers, medium voltage switching facilities and station protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete at Port Colborne TS. The transformers are exhibiting oil leaks and have had performance issues including a catastrophic failed low voltage bushing that caused damage to nearby equipment and compromised supply reliability. • This investment is expected to maintain long-term supply reliability to Canadian Niagara Power Inc. customers and reduce the risk of unplanned outages due to asset failure.	2	8	16
T-SR-03.03	Main TS	• This investment involves the replacement of the power transformers, other ancillary assets, 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. • This investment is also needed to address the capacity increase requested by Toronto Hydro. • This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.04	Wilson TS	• This investment involves the replacement of 230-44 kV transformers, 44kV switchyard, and protection and control equipment • This investment is needed to address the poor condition of the transformers as recent condition assessments show that these units have rapidly degraded as indicated by gassing and cooling system issues as well as poor condition and/or obsolete oil filled circuit breakers and the existing legacy LV switchyard. • The investment is expected to decrease risk of equipment failure, maintain supply reliability to Oshawa PUC and Hydro One Distribution customers and address complaints from neighboring residential community regarding noise emanating from poor condition transformers.	2	13	40

T-SR-03.05	Wonderland TS	• This investment involves the replacement of LV switchyard components including breakers, switches, station services, capacitors and protection & control. • 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 poor condition equipment and removal of legacy obsolete equipment.	0	13	24
T-SR-03.06	Moose Lake TS	• This investment involved the replacement of 115kV transformer, 44kV breaker, instrument transformers, station service transformers, DC station service and transfer scheme and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain system reliability; and is not expected to increase capacity. The benefits of this investment is mitigation of poor equipment health and in turn risk of failure on the system.	2	2	20
T-SR-03.07	Orangeville TS	• This investment involves the replacement of transformers, 44kV transformer breakers, 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 decrease risk of equipment failure, maintain supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	4	4	12
T-SR-03.08	Lambton TS	• This investment involves the replacement of autotransformers, a step-down transformer and LV switchyard components including breakers, switches, protection and control equipment, and the installation of additional station services. • This investment is needed to address equipment that is in poor condition or is obsolete. • The consolidation of two (2) 600 MVA autotransformers into a single larger 1000MVA unit is required as approved by the IESO and identified in the joint Michigan-Ontario interface study with MISO. • The installation of additional station services supplies is needed to comply with OPSRP. 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 poor condition equipment and removal of legacy obsolete equipment.	4	9	22
T-SR-03.09	Crowland TS	• This investment involves the replacement of transformers, the associated protection equipment and reconfiguration and replacement of various 115 kV switches. • This investment is needed to address equipment that is in poor condition or is obsolete. The replacement of the 115 kV switches in the high voltage switchyard is required to meet current regional power flow requirements. This investment is expected to maintain long-term supply reliability to Welland Hydro customers and reduce the risk of unplanned outages due to asset failure	2	0	4

T-SR-03.10	Slater TS	• This investment involves the replacement of transformers, the AC station service system and reconfigure the station DC supply and upgrade associated protection and control equipment at Slater TS. • This investment is needed to address equipment that is in poor condition. This investment is expected to maintain supply reliability to Hydro Ottawa customers and decrease the risk of equipment failure.	2	0	0
T-SR-03.11	Lincoln Heights TS	• This investment involves the replacement of transformers and the protection and control equipment at station. • The investment is needed to address assets in poor condition 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	0	25
T-SR-03.12	Arnprior TS	• This investment involves the replacement of transformers and associated assets, building a new PCT building, replacement of the MV switchyard and reconfiguration of the AC station service. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain supply reliability to Hydro Ottawa customers and decrease the risk of equipment failure.	2	5	17
T-SR-03.13	John TS	• This investment involves the replacement of step-down transformers and associated protective relays, disconnect switches, and neutral reactors. • This investment also involves civil reinforcement for oil spill management. • This investment is needed to address the poor condition of the transformers such as oil leaking, and operational deficiency of tap changers. • The need for the investment is published in Metro Toronto Regional Infrastructure Plan in March 2020. John TS is a critical station to serve loads in downtown Toronto. The investment is expected to mitigate environmental risks of transformer failure in a heavily populated region and maintain load supply reliability to Toronto Hydro.	2	0	0
T-SR-03.14	Rexdale TS	• This investment involves the replacement of existing 27.6kV metalclad switchgear assets with indoor Medium Voltage Gas-Insulated Switchgear (MVGIS) and protection and control systems. • This investment is needed to address the deteriorated condition and obsolescence of the existing 27.6kV metalclad switchgear assets and protections. The existing breaker type is obsolete, not suited for capacitive switching and failures have been experienced in the past. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	22	36
T-SR-03.15	Kirkland Lake TS	• This investment involves the replacement of 44 kV breakers, 115 kV line disconnect switch, instrument transformers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete.	0	8	19

		• This investment addresses the DC battery system to meet standard requirements and risk related to basement flooding. • This investment replaces the obsolete low voltage structure design that does not conform to current safe operation standards that prevents timely maintenance, and to avoid numerous and prolonged outages to Distributed Generator customers. • This investment is expected to maintain reliability to local customers and improve reliability to the broader 115 kV system by the removal of the auto-grounds and implementation of telecommunications. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.16	Fairbank TS	• This investment involves the replacement of 110-28 kV 50/83MVA power transformers and both switchyards at Fairbank TS. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	4	23	41
T-SR-03.17	Bridgman TS	• This investment involves the replacement of power transformers, other ancillary assets, plus the renewal and upgrade of general station infrastructure including support structures, fire walls, spill containment & drainage systems, and noise abatement walls in a complex and space-constrained mid-town Toronto location. • This investment is needed to address the power transformers and station infrastructure in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	4	0	0
T-SR-03.18	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 or is obsolete. This investment is expected to maintain reliability to local area customers and mitigate the risk of outages and supply interruptions due to asset failure.	2	9	19
T-SR-03.19	Lauzon TS	• This investment involves the replacement of 230-27.6kV transformers and the 27.6kV switchyard • This investment is needed to address the poor condition of the transformers as recent condition assessments show that these units have rapidly degraded as indicated by gassing • To accommodate an expected increase in station capacity requirements, the existing 27.6kV low voltage Jones switchyard will be replaced and reconfigured with a Bermondsey switchyard. The investment is expected to decrease risk of equipment failure, maintain supply reliability to EnWin Utilities Ltd. and Hydro One Distribution customers, and ensure the necessary capacity is available to meet the long term customer demand forecast.	3	10	0

Witness: REINMULLER Robert

T-SR-03.20	Longueuil TS	• This investment involves the replacement of 230/44kV, 56/75/93 MVA step-down transformers, transformer spill containment, AC station service, and associated protection and controls equipment at the 55 year old DESN station. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain overall station reliability, eliminate operation risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro One Distribution customers in the area.	2	0	0
T-SR-03.21	Bridgman TS & High Level MS	• This investment involves the replacement of supply breakers associated ancillary components that will supply Toronto Hydro’s replacement A1-A2 switchgear at High Level MS in midtown Toronto. The investment also involves some minor work at Bridgman TS including neutral grounding reactor replacements and current limiting reactor removals. This investment is needed to address equipment that is in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	3	0
T-SR-03.22	Riverdale TS	• This investment involves the replacement of 115kV oil circuit breakers and electromechanical and solid-state protection relays. • This investment is needed to address the poor condition of the circuit breakers and the obsolete protection and control equipment. The investment is expected to maintain supply reliability to Hydro Ottawa customers.	0	2	20
T-SR-03.23	Port Arthur TS	• This investment involves the replacement of 27.6kV circuit breakers, low voltage switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • 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 mitigate the risk of outages and supply interruptions due to asset failure.	0	9	28
T-SR-03.24	Port Hope TS	• This investment involves the replacement of transformers and other 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. The investment is expected to prevent equipment failure, and maintain reliability to Hydro One Distribution customers.	2	9	0
T-SR-03.25	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 or is obsolete. • 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, and mitigate the risk of outages	2	0	2

		and supply interruptions due to asset failure.			
T-SR-03.26	Elliot Lake TS	• This investment involves the replacement of an 115kV/44 kV Transformer, 44 kV breakers; AC station service transfer scheme, DC Battery Charger, AC station service transformers, disconnect switches and protection and control equipment. • 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	3	10
T-SR-03.27	Preston TS	• This investment involves transformers, and associated disconnect switches, surge arresters, neutral grounding reactors, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. • The Kitchener Waterloo Cambridge Guelph Region's Needs Assessment published in December 2018 records the need of this investment. Preston TS is one of the critical stations that serves the Cambridge area and Toyota plant in Cambridge. The investment will mitigate risks of transformer failure and provide operational flexibility to LDCs and help in catering the anticipated future load growth.	2	0	21
T-SR-03.28	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, 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, and decrease the risk of equipment failure.	2	3	7
T-SR-03.29	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, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.30	Scarboro TS	• This investment involves the replacement of the power transformer, other ancillary assets, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment and drainage systems, and noise abatement walls. • This investment is needed to address the power transformer and the general station infrastructure in poor condition. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0

T-SR-03.31	Newton TS	• This investment involves the replacement of 115 kV oil circuit breakers, the associated breaker disconnect switches, 115 kV line switches and associated breaker protection devices • This investment is needed to address poor condition oil breakers. In addition, the PCB content of the breakers exceeds acceptable levels as outlined by Environment Canada and therefore requires attention. This investment is expected to maintain the supply reliability of 115 kV switching facilities at Newton TS that facilitates regional power flows as well as meeting Environment Canada requirements	0	5	0
T-SR-03.32	St. Andrews TS	• This investment involves the replacement of step-down transformers, LV switchyard components including breakers, switches, station services, capacitors and protection and control. • 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 poor condition equipment and removal of legacy obsolete equipment.	2	13	28
T-SR-03.33	Picton TS	• This investment involves the replacement of transformers. • This investment is needed to address the poor condition of the transformers. The investment is expected to maintain supply reliability.	2	0	0
T-SR-03.34	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 or is 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.	1	0	5
T-SR-03.35	Orillia TS	• This investment involves the replacement of a 230kV/44 kV transformer. • This investment is needed to address the transformer in poor condition. 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.	1	0	0
T-SR-03.36	Bracebridge TS	• This investment involves the replacement of T1 power transformer at Bracebridge TS. • This investment is needed to address the transformer in poor condition. 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.	1	0	0
T-SR-03.37	Charles TS	• This investment involves the replacement of non-standard 115/14 kV transformers to the standard size transformers, protection and control equipment, instrument transformers, and the renewal and upgrade of general station infrastructure including spill containment and drainage systems.	2	4	30

		• This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.38	Manby TS	• This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, 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 reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure	0	12	6
T-SR-03.39	Russell TS	• This investment involves the replacement of 115/13.8/13.8kV, 45/60/75 MVA dual secondary transformers, 13.8kV metalclad switchgear, and associated protection and control equipment at the 50 year old station. • This investment is needed to address equipment that is in poor condition or is obsolete. • This investment will also address the recommendation from the recent Greater Ottawa Regional Infrastructure Plan (RIP) report to replace T1/T2 with new 45/60/75 MVA or 60/80/100 MVA units based on anticipated load at the station and giving consideration to right-sizing the transformers. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro Ottawa customers in the area.	2	6	21
T-SR-03.40	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. In addition, Toronto Hydro-Electric System Limited may request these transformers to be replaced with larger standard units in order to meet future supply demand. This investment is expected to maintain long-term supply reliability to Toronto Hydro customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.41	Lake TS	• This investment involves the replacement of transformers, the associated high voltage disconnect switches and protection equipment. • This investment is needed to address equipment that is in poor condition or is obsolete and declining with known manufacturer issues. 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	4	0	4
T-SR-03.42	Bunting TS	• This investment involves the replacement of transformer, station medium voltage switching facilities, and protection and control equipment.	1	17	33

		• This investment is needed to address the non-standard safety compromised medium voltage metalclad switching facilities along with a transformer that is in poor condition, leaking oil that also has tap changer and cooling issues. 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. In addition, the deployment of a new protection and control protocol will enhance Hydro One's ability to provide robust and diverse protection and control schemes for future investments			
T-SR-03.43	Nebo TS	• This investment is 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 or is obsolete. 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	0	4
T-SR-03.44	Palermo TS	• This investment involves the replacement of transformers, associated switches, spill containment facilities, and protection equipment. • This investment is needed to address the poor condition power transformers that also have significant oil leaking issues. This investment is expected to maintain long-term supply reliability to Oakville Hydro customers and reduce the risk of unplanned outages due to asset failure.	2	0	0
T-SR-03.45	Carlton TS	• This investment involves the replacement of medium voltage switching facilities and protection and control systems. • The existing legacy medium voltage switching facilities comprised of an air insulated switchyard and metalclad switching facilities will be replaced with current standard Hydro One metalclad switchgear. • This investment is needed to address the poor condition and safety compromised medium voltage switching assets and structures at Carlton TS along with reconfiguring the station from a four transformer station to a two transformer station based on customer load forecasts. 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	0	24	59
T-SR-03.46	Birmingham TS	• This investment involves the replacement of a 115/ 13.8 kV 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 is highly sensitive to any supply reliability issues. • This investment also addresses a problematic 115 kV line entrance to be reconfigured 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	21	0

T-SR-03.47	Carling TS	• This investment involves the replacement of all electromechanical and solid state protection and control equipment. • This investment is needed to address these assets which are now obsolete. This investment is expected to improve the security of protection operations for Hydro Ottawa customers.	0	0	35
T-SR-03.48	Cherrywood TS	• This investment involves the replacement of 44 kV oil-filled circuit breakers and associated disconnect switches and protection and control equipment. • As a result of the final plan for Fairpoint DS (Elexicon Energy Inc. distribution station located within Cherrywood TS), additional reconfiguration in the 44 kV switchyard may be required. • This investment is needed to address equipment that is in poor condition or is obsolete. • The "right sizing" option was considered and evaluated in the GTA East Regional Infrastructure Planning report published in February 2020 for these assets and it was recommended to replace them like-for-like with current standard equipment. This investment is expected to mitigate the risk of equipment failure and maintain supply reliability to Elexicon Energy Inc and Hydro One Distribution customers in the Pickering area.	0	10	22
T-SR-03.49	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 or is obsolete. 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	15	22
T-SR-03.50	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, and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	0
T-SR-03.51	Fairchild TS	• This investment involves the replacement of the power transformers, protection and control systems, plus the renewal and upgrade of general station infrastructure including fire walls, spill containment and 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 and control systems. This investment is expected to maintain long-term supply reliability to Toronto Hydro and Alectra Utilities customers, and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	34

T-SR-03.52	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 poor condition of the transformers as indicated by recent condition assessments, oil leaks and cooling system issues; poor condition and obsolescence of protection equipment. The investment is expected to decrease risk of equipment failure and maintain supply reliability to Alectra Utilities customers.	2	0	4
T-SR-03.53	Halton TS	• This investment involves the replacement of protection and control systems and other ancillary assets. • This investment is needed to address PALC relays that are obsolete and have a high rate of failure. This investment is expected to maintain long-term supply reliability to Milton Hydro and Halton Hills Hydro customers, mitigate the risk of outages and supply interruptions due to asset failure and obsolescence.	0	0	29
T-SR-03.54	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 or is obsolete. The investment is expected to maintain existing system reliability and load serving capability of the system. 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	5
T-SR-03.55	Kent TS	• This investment involves replacement of 230-27.6kV 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 or is obsolete. 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	11	19
T-SR-03.56	Muskoka TS	• This investment involves the replacement of 44kV circuit breakers, low voltage switches, station service transformers, and instrument transformers. • 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 to mitigate the risk of outages and supply interruptions due to asset failure.	0	7	0
T-SR-03.57	Timmins TS	• This investment involves the replacement of a 115kV stepdown transformer and the associated electro-mechanical protection. • 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. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	1	0	1

T-SR-03.58	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 or is obsolete. • 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.	4	21	64
T-SR-03.59	Vansickle TS	• This investment involves the replacement of metalclad switchgear 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 reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	9	13
T-SR-03.60	Dundas TS	• This investment involves the replacement of 27.6 kV low voltage switchgear. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to the local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	13	8
T-SR-03.61	Mohawk TS	• This investment involves the replacement of 13.8 kV low voltage switchgear 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 supply reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	6	17
T-SR-03.62	Bathurst TS	• This investment involves the replacement of a step-down transformer, circuit breakers, and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers, and mitigate the risk of outages and supply interruptions due to asset failure.	1	7	11
T-SR-03.63	Leslie TS	• This investment involves the replacement of a 230/27.6/13.8kV 75/125MVA power transformer, 27.6kV and 13.8kV breakers and switches, protection and control system upgrade and other auxiliary assets. • This investment is needed to address the poor condition and performance of the assets and the obsolete protection and control equipment. This investment is expected to maintain supply reliability to local customers (Toronto Hydro and Alectra), and mitigate the risk of outages and supply interruptions due to asset failure.	1	8	43
T-SR-03.64	Burlington TS	• This investment involves the replacement of 27.6 kV low voltage switchgear and protection and control equipment.	0	9	32

		• This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain supply reliability to local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.			
T-SR-03.65	Alliston TS	• This project involves the replacement of 230/44kV step-down transformers • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. 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	2	0
T-SR-03.66	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 station. • This investment is needed to address assets in poor condition based on the asset condition assessment. This investment is expected to reduce risk of equipment failure, and maintain reliability of the BES and to Hydro One customers.	4	19	48
T-SR-03.67	Strachan TS	• This investment involves the replacement of 110/14-14kV 45/75MVA transformers 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 reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	3	0	8
T-SR-03.68 A&B	Clarke TS	• This investment involves the replacement of step-down transformers, associated disconnect switches, LV switchyard components including breakers, station services, capacitors and protections. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	9	20
T-SR-03.69	Albion TS	• This investment involves the replacement of transformers, 13.8kV breakers, and associated protection and control equipment at the station. • This investment is needed to address these assets in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	2	12	25
T-SR-03.70	Bilberry Creek TS	• This investment involves the replacement of transformers, oil circuit breakers, and associated protection and control equipment at the station. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro One Distribution and Hydro Ottawa customers.	2	5	17

T-SR-03.71	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 or is obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with equipment in poor condition and removal of obsolete equipment.	2	9	0
T-SR-03.72	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 or that are obsolete. • 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 poor condition equipment, and ensure continued supply reliability to Hydro One Distribution customers in the area.	2	3	7
T-SR-03.73	Lisgar TS	• This investment involves the replacement of a transformer and protection and control equipment. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to reduce the risk of equipment failure and maintain reliability of supply to Hydro Ottawa customers.	1	0	22
T-SR-03.74	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 T3 and T4 transformers. This investment is also needed to eliminate PCB contaminated equipment in the station in order to comply with environmental regulations. • In addition, Toronto Hydro-Electric System Limited may request these transformers to be replaced with larger standard units in order to meet future supply demand. This investment is expected to maintain long-term supply reliability to Toronto Hydro-Electric System Limited customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.75	Crystal Falls	• This investment involves the replacement of 230/44kV step-down transformers, 44kV breakers, switches, station service transformers, instrument transformers, 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 expected to increase existing system capacity. 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	3	13

T-SR-03.76	Douglas Point TS	• This investment involves the replacement of 230/44kV step-down transformers including Oil Water Separators, 44kV Breakers, 230kV Air Break Switches, 44kV Switches, 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. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	10	25
T-SR-03.77	Trout Lake TS	• This investment involves the replacement of 230/44 kV 75/125 MVA power transformers and 44 kV breakers. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain reliability to local customers. The benefits of this investment are to mitigate the risk of outages and supply interruptions due to asset failure.	2	5	0
T-SR-03.78	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; the degraded condition of select high voltage and low voltage breakers. The investment is expected to decrease the risk of equipment failure and maintain supply reliability to Hydro One Distribution customers in the city of Windsor.	1	3	37
T-SR-03.79	Galt TS	• This investment involves the replacement of the oil circuit breakers and associated protection and control equipment at the station. • This investment is needed to address equipment that is in poor condition or is obsolete. • Kitchener Waterloo Cambridge Guelph Region's Integrated Regional Resource Plan (IRRP) notes the need of this investment. Galt TS is one of the critical stations to serve Cambridge area. The investment will mitigate risks of breaker failure.	0	14	24
T-SR-03.80	Martindale TS	• This investment involves the replacement of two transformers. • The investment is needed to address transformers in poor condition. 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	6	0
T-SR-03.81	Bruce HWB TS	• This investment involves the replacement of step-down transformers, oil water separators, 13.8kV breakers, 230kV switches, and protection equipment. • The investment is needed to address assets in poor condition or that are obsolete. The investment is expected to maintain existing system reliability. The benefits of this investment are mitigation of risk associated with poor condition equipment and removal of legacy obsolete equipment.	2	3	19

T-SR-03.82	Campbell TS	• This investment involves the replacement of breakers and protection and control systems, plus the renewal and upgrade of general station infrastructure including HVAC and Fire Alarm systems. • This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to maintain long-term supply reliability to London Hydro customers, mitigate the risk of outages and supply interruptions due to asset failure.	0	3	32
T-SR-03.83	Bramalea TS	• This investment involves the replacement 230/44kV 50/83MVA transformers. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	6
T-SR-03.84	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 in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	1	56
T-SR-03.85	Gardiner TS	• This investment involves the replacement of 230/44kV, 75/100/125 MVA step-down transformers, transformer spill containment, AC station service, and associated protection and control equipment. • This investment is needed to address assets in poor condition or that are obsolete. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One distribution customers in the region.	2	3	24
T-SR-03.86	Morrisburg TS	• This investment involves the replacement of AC station service, DC station service, and protection and control equipment at the 60 year old station. • This investment is needed to address these assets in poor condition 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.	0	0	31
T-SR-03.87	Nepean TS	• This investment involves the replacement of 230/44kV, 75/100/125 MVA transformers, DC station service, and oil-water separator. • Transformers T1/T2 will be replaced with new, similar size 75/100/125 MVA units, giving consideration to right-sizing the transformers. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain overall station reliability, eliminate operational risks associated with operating poor condition equipment, and ensure continued supply reliability to Hydro Ottawa customers in the area.	2	0	0
T-SR-03.88	Beach TS	• This investment involves the replacement of transformers, and the medium voltage legacy metalclad switchgear.	2	22	0

		• This investment is needed to address equipment that is in poor condition or is obsolete. 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.			
T-SR-03.89	Port Arthur TS	• This investment involves the replacement of 115kV circuit breakers, high voltage switches, AC and DC station service equipment, instrument transformers, and protection and control equipment. • 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 mitigate the risk of outages and supply interruptions due to asset failure.	0	8	9
T-SR-03.90	South March TS	• This investment involves the replacement of 230/44kV, 50/67/83 MVA step-down transformers and protection and control equipment. • This investment is needed to address assets in poor condition or is obsolete. The investment is expected to mitigate risk of equipment failure and maintain supply reliability to Hydro One customers in the Ottawa area.	2	0	21
T-SR-03.91	Clarabelle TS	• This investment involves the replacement of 230/44kV 125MVA step-down transformers. • This investment is needed to address equipment that is in poor condition. The investment is expected to maintain existing system reliability. 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	2	0
T-SR-03.92	Tomken TS	• This investment involves the replacement of 44 kV low voltage switchgear and protection and control equipment. This investment is needed to address equipment that is in poor condition. The investment is required to maintain supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to assets failure.	0	26	0
T-SR-03.93	Malvern TS	• This investment involves the replacement of a 230/27.6kV 75/125MVA power transformer, 27.6kV capacitor banks, and protection and control system upgrades. • The investment is needed to address the poor condition and performance of the transformer and capacitor banks, and the obsolete protection and control equipment. This investment is expected to maintain supply reliability to local customers (Toronto Hydro and Elexicon), and mitigate the risk of outages and supply interruptions due to asset failure.	1	0	17
T-SR-03.94	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 poor condition. • The investment is expected to maintain existing system reliability and load serving capability of the	1	0	0

		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.			
T-SR-03.95	Caledonia TS	• This investment involves the replacement of a 230/27.6 kV station supply transformer, breaker 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 supply reliability to the local customers supplied by this station, and mitigate the risk of outages and supply interruptions due to asset failure.	1	1	9
T-SR-03.96	Finch TS	• This investment involves the replacement of the low voltage switchyard and components including 28kV breakers, switches, 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 reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure.	0	15	34
T-SR-03.97	Tomken TS	• This investment involves the replacement of step-down transformers and station infrastructure including spill containment. • This investment is needed to address the poor condition of the T1 and T2 transformers. This investment is expected to maintain long-term supply reliability to Alectra customers, and mitigate the risk of outages and supply interruptions due to asset failure.	2	0	0
T-SR-03.98	Murray TS	• This investment involves the replacement of power transformers. • This investment is needed to address equipment that is in poor condition. 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	0	0
T-SR-03.99	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 or is obsolete. 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.	0	27	7
T-SR-03.100	Stratford TS	• This investment involves the replacement of the 27.6kV switchyard and protection and control equipment. This investment is needed to address equipment that is in poor condition or is obsolete. This investment is expected to decrease risk of equipment failure and maintain long-term reliability of supply to Hydro	0	13	30

		One Distribution and Festival Hydro Inc. customers in the town of Stratford and surrounding area.			
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. • This investment is needed to address equipment that is in poor condition or is obsolete. The investment is expected to maintain reliability to local customers and mitigate the risk of outages and supply interruptions due to asset failure	0	4	67
T-SR-03.102	Fergus TS	• This investment involves the replacement of transformers, oil circuit breakers, associated disconnect switches, and instrument transformers. • This investment is needed to address equipment that is in poor condition or is obsolete. • Kitchener Waterloo Cambridge Guelph Region's Integrated Regional Resource Plan (IRRP) notes the need of this investment. Fergus TS is one of the critical stations to serve the load in Fergus and surrounding areas. The investment will mitigate risks of transformer and other component failure at the station.	2	8	0
	Total		**151**	**609**	**1570**

APPENDIX B – DETAILED INVESTMENT COSTS

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 2.10. 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 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 – Capital Expenditures

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	2024	2025	2026	2027	23-27 Total	Project Total	
T-SR-03.01	Parry Sound TS	SR-05	E	8.2	0.0	0.0	0.0	0.0	8.2	23.0	2022
T-SR-03.02	Port Colborne TS	SR-02	E	9.2	0.0	0.0	0.0	0.0	9.2	31.0	2022
T-SR-03.03	Main TS	SR-05	E	4.0	0.0	0.0	0.0	0.0	4.0	33.9	2023
T-SR-03.04	Wilson TS	SR-05	P	14.3	0.0	0.0	0.0	0.0	14.3	41.4	2023
T-SR-03.05	Wonderland TS	SR-02	P	7.1	0.0	0.0	0.0	0.0	7.1	24.7	2023
T-SR-03.06	Moose Lake TS	SR-05	P	3.1	2.8	0.6	0.0	0.0	6.5	8.8	2023

T-SR-03.07	Orangeville TS	SR-05	E	10.3	4.7	0.0	0.0	0.0	15.0	34.5	2023
T-SR-03.08	Lambton TS	SR-02	P	17.0	0.0	0.0	0.0	0.0	17.0	47.7	2023
T-SR-03.09	Crowland TS	SR-05	P	9.5	10.0	0.0	0.0	0.0	19.5	35.8	2023
T-SR-03.10	Slater TS	SR-02	E	7.6	8.3	0.0	0.0	0.0	15.9	29.0	2023
T-SR-03.11	Lincoln Heights TS	-	P	14.0	2.9	0.0	0.0	0.0	16.9	21.4	2023
T-SR-03.12	Arnprior TS	SR-02	E	13.5	0.0	0.0	0.0	0.0	13.5	28.3	2023
T-SR-03.13	John TS	-	P	10.4	7.7	0.0	0.0	0.0	18.1	20.9	2024
T-SR-03.14	Rexdale TS	SR-06	E	8.5	6.3	0.0	0.0	0.0	14.9	29.3	2024
T-SR-03.15	Kirkland Lake TS	SR-06	P	7.5	6.6	0.0	0.0	0.0	14.1	27.7	2024
T-SR-03.16	Fairbank TS	SR-02	E	13.1	12.3	6.7	0.0	0.0	32.2	68.4	2024
T-SR-03.17	Bridgman TS	SR-05	E	16.8	13.7	0.0	0.0	0.0	30.5	65.2	2024
T-SR-03.18	Murray TS	SR-05	P	18.9	17.1	0.0	0.0	0.0	36.0	39.3	2024
T-SR-03.19	Lauzon TS	SR-05	P	20.8	15.8	0.0	0.0	0.0	36.6	41.2	2024
T-SR-03.20	Longueuil TS	SR-05	P	8.5	6.4	0.0	0.0	0.0	14.9	17.0	2024

T-SR-03.21	Bridgman TS	-	P	3.8	2.7	0.0	0.0	0.0	6.5	3.7	2024
T-SR-03.22	Riverdale TS	-	P	2.8	3.8	0.0	0.0	0.0	6.6	7.0	2024
T-SR-03.23	Port Arthur TS #1	SR-06	P	9.9	9.8	3.2	0.0	0.0	22.9	24.2	2025
T-SR-03.24	Port Hope TS	SR-05	P	7.3	7.4	8.8	0.0	0.0	23.6	23.8	2025
T-SR-03.25	Manby TS	-	P	4.1	7.7	3.9	0.0	0.0	15.7	16.8	2025
T-SR-03.26	Elliot Lake TS	SR-05	P	7.3	8.0	5.4	0.0	0.0	20.7	23.5	2025
T-SR-03.27	Preston TS	SR-05	P	4.8	10.9	6.4	0.0	0.0	22.1	22.9	2025
T-SR-03.28	Wallace TS	SR-05	P	4.3	7.8	5.8	1.6	0.0	19.7	20.3	2025
T-SR-03.29	Bermondsey TS	SR-05	P	3.6	10.4	5.9	0.0	0.0	19.8	20.6	2025
T-SR-03.30	Scarboro TS	-	P	1.6	4.7	2.8	0.0	0.0	9.1	9.7	2025
T-SR-03.31	Newton TS	-	P	4.5	4.1	2.3	0.0	0.0	11.0	12.6	2025
T-SR-03.32	St. Andrews TS	SR-02	P	5.1	19.0	19.2	0.0	0.0	43.3	43.8	2025
T-SR-03.33	Picton TS	-	P	1.3	7.4	4.8	0.0	0.0	13.5	14.0	2025
T-SR-03.34	Midhurst TS	-	P	1.4	3.8	2.8	0.6	0.0	8.7	9.2	2025

T-SR-03.35	Orillia TS	-	P	0.7	4.0	2.8	0.0	0.0	7.5	8.0	2025
T-SR-03.36	Bracebridge TS	-	P	0.7	3.6	2.9	0.4	0.0	7.6	8.0	2026
T-SR-03.37	Charles TS	SR-05	P	3.2	10.9	11.6	3.7	0.0	29.4	30.1	2026
T-SR-03.38	Manby TS	-	P	4.0	5.9	6.2	4.5	0.0	20.6	21.0	2026
T-SR-03.39	Russell TS	SR-05	P	1.0	7.6	10.7	4.9	0.0	24.2	24.4	2026
T-SR-03.40	Duplex TS	SR-05	P	1.2	7.1	9.8	3.8	0.0	21.8	22.5	2026
T-SR-03.41	Lake TS	SR-06	P	8.5	11.2	7.8	3.4	0.0	30.9	33.8	2026
T-SR-03.42	Bunting TS	SR-06	P	2.7	8.9	17.8	6.6	0.0	36.0	41.0	2026
T-SR-03.43	Nebo TS	-	P	0.3	1.6	9.5	7.6	0.0	19.0	19.0	2026
T-SR-03.44	Palermo TS	SR-05	P	0.7	3.4	12.7	2.6	0.0	19.4	19.5	2026
T-SR-03.45	Carlton TS	SR-02	P	6.6	12.2	14.5	-0.1	0.0	33.2	36.0	2026
T-SR-03.46	Birmingham TS	SR-05	P	1.0	3.4	13.2	7.9	0.0	25.5	25.7	2026
T-SR-03.47	Carling TS	-	P	0.2	0.6	3.2	4.9	0.0	8.9	8.9	2026
T-SR-03.48	Cherrywood TS	SR-06	P	0.6	1.4	8.0	5.2	0.0	15.3	15.6	2026

T-SR-03.49	Gage TS	SR-05	P	0.7	3.0	12.1	8.3	0.7	24.9	25.1	2026
T-SR-03.50	Woodbridge TS	SR-05	P	0.6	0.9	5.2	4.7	1.0	12.4	12.6	2027
T-SR-03.51	Fairchild TS	SR-05	P	0.7	3.4	14.9	16.8	4.5	40.2	40.5	2027
T-SR-03.52	Cedar TS	SR-05	P	1.4	5.0	8.2	6.5	1.9	23.0	23.6	2027
T-SR-03.53	Halton TS	SR-07	P	0.5	0.6	2.7	4.4	1.9	10.1	10.3	2027
T-SR-03.54	Waubaushene TS	-	P	0.5	1.0	3.9	8.1	4.2	17.7	17.8	2027
T-SR-03.55	Kent TS	SR-02	P	0.5	1.2	5.4	13.5	7.4	28.0	28.1	2027
T-SR-03.56	Muskoka TS	SR-06	P	0.3	0.6	1.4	3.5	1.8	7.6	7.6	2027
T-SR-03.57	Timmins TS	-	P	0.2	0.6	1.3	4.0	2.3	8.5	8.5	2027
T-SR-03.58	Glendale TS	SR-02	P	7.3	9.3	12.0	11.5	7.3	47.4	55.0	2027
T-SR-03.59	Vansickle TS	SR-06	P	0.3	0.7	1.4	5.6	3.4	11.4	14.5	2027
T-SR-03.60	Dundas TS	SR-06	P	0.2	0.6	1.1	5.9	3.7	11.5	11.5	2027
T-SR-03.61	Mohawk TS	SR-06	P	0.2	0.5	0.9	5.0	3.2	9.8	9.8	2027
T-SR-03.62	Bathurst TS	SR-05	P	0.3	0.6	1.7	9.2	5.8	17.5	17.5	2027

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T-SR-03.63	Leslie TS	SR-05	P	0.3	0.6	3.2	18.1	11.8	33.9	33.9	2027
T-SR-03.64	Burlington TS	SR-06	P	0.4	0.5	1.4	5.4	3.7	11.3	11.6	2027
T-SR-03.65	Alliston TS	-	P	0.2	0.6	1.4	7.9	6.5	16.7	17.7	2028
T-SR-03.66	Dobbin TS	-	P	1.9	9.8	24.5	33.4	23.8	93.5	100.8	2028
T-SR-03.67	Strachan TS	SR-05	P	0.2	0.8	3.8	16.3	16.3	37.4	42.0	2028
T-SR-03.68a	Clarke TS	-	P	0.2	0.6	1.7	9.4	8.6	20.4	22.3	2028
T-SR-03.68b	Clarke TS	SR-05	P	0.2	0.6	1.9	10.7	9.7	23.1	25.2	2028
T-SR-03.69	Albion TS	-	P	0.2	0.6	2.6	15.7	19.2	38.3	44.9	2028
T-SR-03.70	Bilberry Creek TS	SR-05	P	0.2	0.6	1.5	8.7	10.6	21.5	25.1	2028
T-SR-03.71	Talbot TS	-	P	0.2	0.6	1.6	9.9	12.1	24.5	28.6	2028
T-SR-03.72	Havelock TS	-	P	0.1	0.5	1.1	6.1	8.6	16.5	19.9	2028
T-SR-03.73	Lisgar TS	-	P	0.0	0.7	0.8	3.8	5.4	10.6	12.7	2028
T-SR-03.74	Duplex TS	-	P	0.1	0.5	1.1	6.4	10.4	18.5	23.1	2028
T-SR-03.75	Crystal Falls TS	-	P	0.1	0.5	1.5	8.4	11.1	21.7	27.8	2028

T-SR-03.76	Douglas Point TS	-	P	0.1	0.4	1.4	7.7	11.3	21.0	28.0	2028
T-SR-03.77	Trout Lake TS	-	P	0.0	0.6	0.9	4.6	9.0	15.0	19.4	2028
T-SR-03.78	Lauzon TS	-	P	0.0	0.5	1.3	7.8	15.1	24.7	32.8	2028
T-SR-03.79	Galt TS	-	P	0.0	0.5	0.6	2.5	6.0	9.6	12.8	2028
T-SR-03.80	Martindale TS	-	P	0.5	0.9	3.3	7.2	7.9	19.7	23.2	2028
T-SR-03.81	Bruce B HWP TS	-	P	0.0	0.5	0.8	4.6	13.7	19.5	27.4	2028
T-SR-03.82	Campbell TS	SR-06	P	0.0	0.2	1.1	7.2	7.1	15.6	18.1	2028
T-SR-03.83	Bramalea TS	-	P	0.1	0.4	0.5	2.5	9.7	13.3	19.1	2028
T-SR-03.84	Erindale TS	SR-07	P	0.0	0.3	0.6	2.2	12.1	15.1	23.0	2028
T-SR-03.85	Gardiner TS	-	P	0.0	0.3	0.7	2.5	13.8	17.2	26.2	2028
T-SR-03.86	Morrisburg TS	-	P	0.0	0.0	0.2	0.6	3.7	4.5	10.2	2028
T-SR-03.87	Nepean TS	-	P	0.0	0.3	0.6	1.5	8.6	11.0	16.6	2028
T-SR-03.88	Beach TS	-	P	0.0	0.2	0.6	8.3	15.0	24.2	40.4	2028
T-SR-03.89	Port Arthur TS #1	-	P	0.2	0.5	0.9	2.9	3.9	8.4	10.4	2028

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T-SR-03.90	South March TS	-	P	0.0	0.3	0.6	1.9	10.5	13.3	20.1	2028
T-SR-03.91	Clarabelle TS	-	P	0.0	0.3	0.6	1.7	9.4	11.9	18.0	2028
T-SR-03.92	Tomken TS	-	P	0.0	0.2	0.6	1.9	11.3	14.1	23.3	2029
T-SR-03.93	Malvern TS	-	P	0.0	0.3	0.7	1.6	6.7	9.3	15.3	2029
T-SR-03.94	Allanburg TS	-	P	0.0	0.2	0.5	1.1	4.3	6.1	10.7	2029
T-SR-03.95	Caledonia TS	-	P	0.0	0.2	0.5	1.1	4.1	5.9	10.2	2029
T-SR-03.96	Finch TS	SR-06	P	0.0	0.2	0.6	1.8	5.2	7.9	32.0	2029
T-SR-03.97	Tomken TS	-	P	0.0	0.2	0.6	1.4	6.5	8.6	24.0	2029
T-SR-03.98	Murray TS	-	P	0.0	0.2	0.6	1.0	5.3	7.1	17.3	2029
T-SR-03.99	Lake TS	-	P	0.0	0.3	0.9	3.4	8.8	13.4	25.3	2029
T-SR-03.100	Stratford TS	-	P	0.0	0.1	0.5	1.3	7.2	9.2	25.1	2029
T-SR-03.101	Bramalea TS	SR-07	P	0.0	0.0	0.3	0.9	3.9	5.2	27.2	2030
T-SR-03.102	Fergus TS	-	P	0.0	0.0	0.1	0.6	1.4	2.1	26.1	2030
Net Investment Cost				**334.5**	**357.7**	**350.1**	**406.5**	**428.6**	**1877.3**	**2534.6**	

Witness: REINMULLER Robert

T-SR-04	**WOOD POLE STRUCTURE REPLACEMENTS**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($ Millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	56.5	57.6	58.8	60.0	61.2	294.0

Summary:

This investment involves the replacement of wood pole structures identified to be in poor condition. The primary triggers of the investment are failure and safety related risks. The investment is expected to maintain system reliability, and reduce safety risk to employees and the public associated with failing structures.

A. OVERVIEW

Wood Pole Structure Replacement Program (the "Investment") involves the replacement of wood poles whose deteriorated condition pose reliability and safety risk. Wood poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. Poles with reduced strength present operational risks to Hydro One crews, safety risks to the public, and reliability risks to the overhead transmission system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios, thereby creating significant public safety risk and prolonged service disruptions. Furthermore, the majority of the wood pole fleet is located in Northern Ontario, including many that support radial circuits. This means that a wood pole or cross-arm failure as a result of deteriorated condition can directly cause a customer outage. Hydro One utilizes a condition based inspection approach to identify wood pole structures that are in poor condition, requiring replacement. To ensure Hydro One maintains system reliability, and reduces safety risk to its employees and the public, the Investment targets the replacement of approximately 1,080 wood poles each year, totalling 5,400 wood poles over the 2023-2027 planning period. Hydro One has evaluated various alternatives for the Investment, as further described below and concluded that the most prudent and cost effective undertaking is to replace the poor condition wood poles at the proposed pace.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

Wood poles structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. Wood pole structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 230 kV. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access.

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location.

Wood poles are deemed to be in poor condition when the surface condition degrades and the poles are no longer climbable; there is significant surface and pole top rot; or where wood pecker holes have weakened the strength of the pole. Poles that are drilled and have 2.5 inches or less of solid circumferential wood remaining from internal rot will be replaced as they have fallen below their required design strength. All wood poles and components are to be replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions. Based on wood pole assessments, approximately 4,700 (12%) of Hydro One's wood pole population requires replacement, as further outlined in Figure 1 below. These poor condition poles typically exhibit woodpecker damage, mechanical damage or insect damage. About 23,900 (60%) of the population is either in good condition or not yet eligible for assessment (these poles are under 25 years old and therefore they do not currently meet the criteria for assessment). The remaining 11,500 (29%) of the wood pole population are backlogged in terms of detailed condition assessment and need to be assessed to determine its condition. By evaluating the current age of the wood poles and based on its experience, Hydro One anticipates that approximately 30% of the yet to be assessed wood poles would be identified to be in poor condition upon condition assessment. Trending the results from the condition assessment program for the past five years (2016-2020), Hydro One forecasts to identify around 500 poor condition wood poles annually.

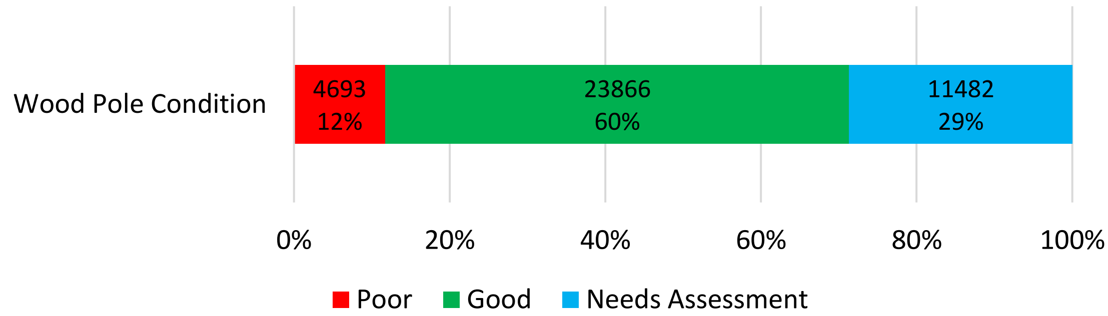

Figure 1: Wood Pole Population

The majority of the 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 wood pole circuits feed industrial customers, who may be forced to shut down until power is restored. Such an event can add significant cost to a customer's operations. Moreover, these Northern circuits supply electricity to local distribution companies in Indigenous communities, which would be adversely affected by any supply interruption.

As shown in Figure 2 below, the number of forced outages due to wood pole structure failures has increased over the past ten years. Wood pole failure is the result of a combination of factors, such as pole condition, weather condition, physical loading, and the local environment.

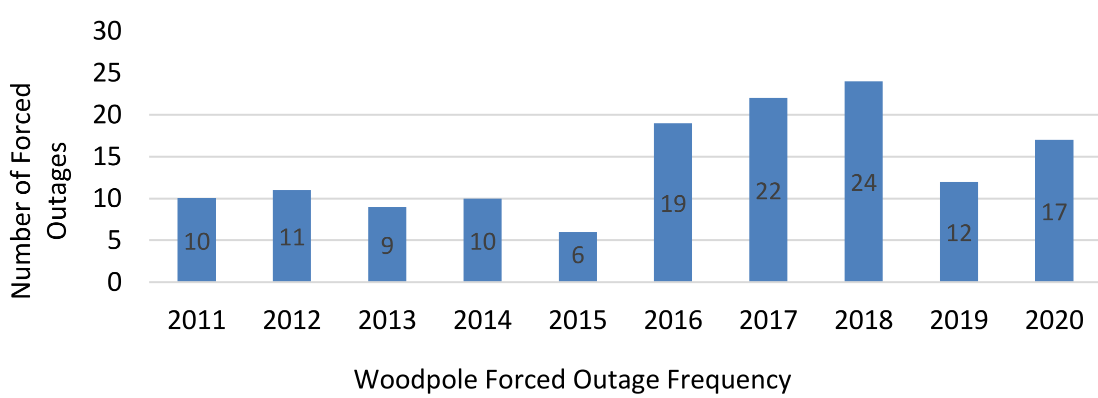

Figure 2: Forced Outage Frequency Due to Wood Pole Failures

As shown in Figure 3 below, the forced outage duration due to wood pole failures has generally increased over the past ten years.

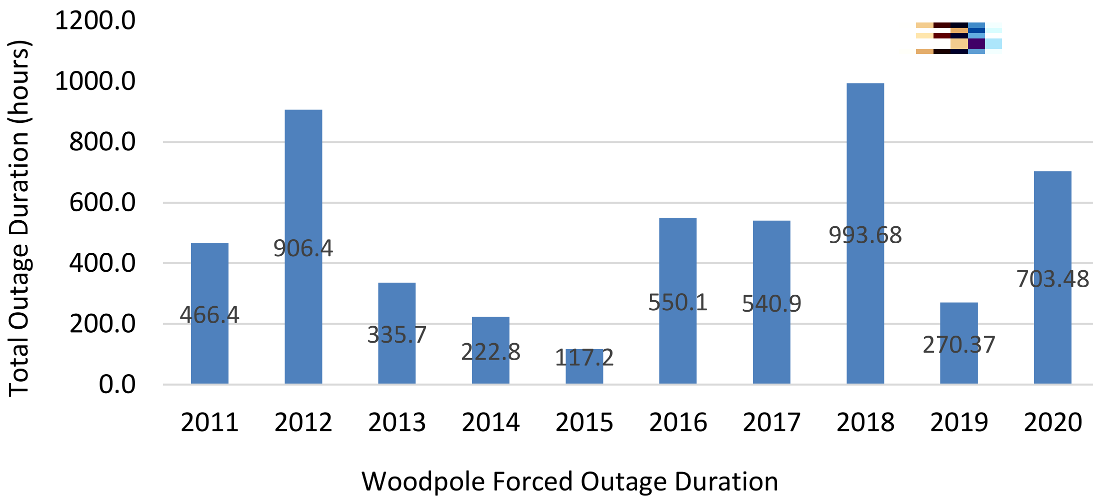

Figure 3: Forced Outage Duration due to Wood Pole Failures

Figure 4 illustrates a failure of a wood pole.

Figure 5 illustrates rotten pole tops that could fail imminently.

Figure 4: Downed Wood Pole on Circuit M1T

Figure 5: Rotten Pole Tops on M1T that Could Fail Imminently

As further described in TSP Section 2.3, in 2020, Guidehouse Canada Ltd. and First Quartile Consulting conducted a benchmarking study for Hydro One regarding the replacement rate of transmission wood poles in comparison with other North American utilities. Two of the key findings are as follow:

- Compared to other North American utilities that participated in the study, Hydro One has the second highest percentage of wood poles installed before 1960.
- Compared to other North American utilities that participated in the study, Hydro One's replacement rate over the past 5 years, 2.1%, has been below the mean of 2.6%.

C. INVESTMENT DESCRIPTION

Hydro One will continue to replace wood poles that are in poor condition identified by condition assessments. Wood pole structure condition is collected from visual inspections of the various components that make up the structure, including the cross-arms. Visual inspections include both a detailed helicopter inspection to assess the upper area of wood structures and a ground line inspection to assess the lower part of wood structures. In addition to the visual inspections, other diagnostic testing that focuses on internal rot and wood pecker holes is used to assess condition. Representative samples of wood poles are drilled once they meet a certain age criteria to determine the presence of internal rot.

The wood pole structures scheduled for replacement will be replaced with new wood pole or composite structures. The Investment targets the replacement of approximately 1,080 wood poles each year, totalling 5,400 wood poles over the 2023-2027 period. The Investment's replacement levels for the 2023-2027 period have been summarized in Table 1.

Table 1 - Wood Pole Structure Replacements

Wood Structures	Forecast Period				
	2023F	**2024F**	**2025F**	**2026F**	**2027F**
Units	1076	1076	1078	1082	1084
% of Fleet	2.6%	2.6%	2.7%	2.7%	2.7%

D. OUTCOMES

D.1 OEB RRF OUTCOMES

As a result of the Investment, Hydro One will maintain system reliability, and reduce safety risk to employees and the public associated with failing structures. Through the customer engagement process, Hydro One has heard from its customers that they need Hydro One to pay more attention to addressing situations today that can provide greater reliability and lower costs in the future. The Investment is an exemplary investment to address all of the aforementioned concerns.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - 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.

E. EXPENDITURE PLAN

Table 3 below presents forecasted costs for the Investment. Costs are based on an average unit cost estimate calculated utilizing historical replacement costs.

Table 3 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	61.4	62.6	63.9	65.2	66.5	319.6
Less Removals	4.9	5.0	5.1	5.2	5.3	25.6
Capital and Minor Fixed Assets	**56.5**	**57.6**	**58.8**	**60.0**	**61.2**	**294.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**56.5**	**57.6**	**58.8**	**60.0**	**61.2**	**294.0**

The factors influencing the cost of the investment include:

- Structure type – The cost varies depending on whether it is single pole, two-pole or three-pole structure. The larger the structure, the more expensive it is to replace. Likewise, a dead-end structure will be more difficult and costly to replace.
- 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.
- Location of the pole (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's a sensitive area to access) – crossing an environmentally sensitive area requires time and money to be spent on permits.

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The “Do Nothing” - Reactive Pole Replacement involves waiting for the wood poles that are in poor condition to fail and replace the failed wood poles on a reactive basis. This alternative has been rejected since the reactive management of transmission lines wood poles would lead to increased asset failures resulting in elevated safety and reliability risks. In addition, as wood poles 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:

Pole replacement Based on Risk Mitigation Assessments is the preferred undertaking. Plan to replace poor condition wood poles based on risk mitigation assessments. This alternative will address poor condition wood poles to mitigate the safety and reliability risks that balance wood poles needs, resource availability, and cost impact to customers. This alternative is selected, as it will maintain the safety and reliability of the transmission system.

G. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Investment include access to the assets depending on the season, and equipment outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial Investment planning phase where all known risks are identified and 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.

T-SR-05	**STEEL STRUCTURE COATING PROGRAM**
Primary Trigger:	Cost Avoidance
OEB RRF Outcomes:	Customer Focus, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	$23.6	$24.1	$24.5	$25.0	$25.4	$122.7

Summary:

This investment involves coating corroded transmission line steel structures with zinc-based product thereby providing on-going protection to the underlying carbon steel and preserving the steel structure integrity. The primary trigger of the investment is cost avoidance. The investment is expected to extend the asset service life, hence, minimize life cycle cost in managing steel structures by preventing higher capital expenditures in the future due to costly steel member or complete structure replacement.

A. OVERVIEW

The Steel Structure Coating Program (the "Investment") involves coating corroded transmission line steel structures, thereby providing on-going protection to the underlying carbon steel and preserving the steel structure integrity. Steel structures are manufactured from carbon steel and protected by hot dip galvanizing (HDG), a zinc based product 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 the Investment, 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 on-going protection to the underlying carbon steel, thereby preserving the steel structure integrity. Structure coating is not intended to prevent immediate structure failures. The rate of failure for structures is dependent on the condition of the structures and the impact of adverse environmental factors which is not predictable, such as wind and ice. 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 an exemplary program that considers repair versus replace options. In this case, repairing the asset by coating, which extends asset service life, is the preferred option that results in a significant present value positive investment. Hydro One has evaluated various alternatives for the Investment, as further described below, and concluded that the coating of 500 corroded steel towers per year, consistent with historical pacing, appropriately balances the safety and reliability risks with the economic benefit. The projected costs of the Investment are estimated to be $122.7M over the 2023-2027 test period.

B. NEED AND OUTCOME

B.1 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 115 kV to 500 kV. As explained in TSP Section 2.2, Hydro One has approximately 49,200 lattice steel structures and approximately 1,750 steel poles supporting 115kV to 500kV transmission lines. Current steel structures have an average age of 63 years and an ESL of 80 years if they are not re-coated. However, if re-coated, the steel structures' service life can extend beyond the ESL. The demographics of the steel structure population are outlined in Table 1 below.

Table 1 - Steel Structure Demographics

	Quantity	Average Age	ESL (Years)	Beyond ESL Currently
Steel Towers in Light Corrosion Zones (C2 and C3)	10,400	61	80	2,600
Steel Towers In High to Very High Corrosion Zones (C4 and C5)	38,800	63	80	8,800
Steel Poles	1,750	37	80	85
Total	50,950	61	80	11,485

Steel structures are manufactured from carbon steel and protected by hot dip galvanizing (HDG), a zinc based product to protect the steel from corrosion. Based on the 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, as once a structure has lost its galvanizing protection the carbon steel is exposed to the environment, and the corrosion rate of the structure accelerates by a factor of eight to ten. If steel corrosion is not addressed prior to corrosion setting in, the steel structure will begin to lose structural strength and the only option would be partial or complete replacement of the tower. When the structural strength diminishes below design strength, the integrity and capacity of the structure is compromised and a failure may occur under certain weather loading conditions. Figure 1 illustrates the steel transmission towers from Sarnia region which exhibit heavy pitting corrosion and require complete replacement.

Figure 1: Steel Structures in the Sarnia area exhibiting heavy pitting corrosion

Recoating the structure with zinc-based product will provide on-going protection to the underlying carbon steel and preserve the steel structure. It will extend the steel tower service life by restoring the protective layer of galvanized coating, thereby avoiding the more costly option of replacement.

Hydro One continues to utilize the EPRI study from 2017 that defines corrosion zones and corrosion rates in the province of Ontario and assesses the impact of corrosion to Hydro One's transmission towers. EPRI utilized the international standard, ISO 9223:2012, *Corrosion of metals and alloys - Corrosivity of atmospheres – Classification,* to classify the province of Ontario into four corrosion zones ranging from C2 to C5. Figure 2 illustrates corrosion zones in Ontario. 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.

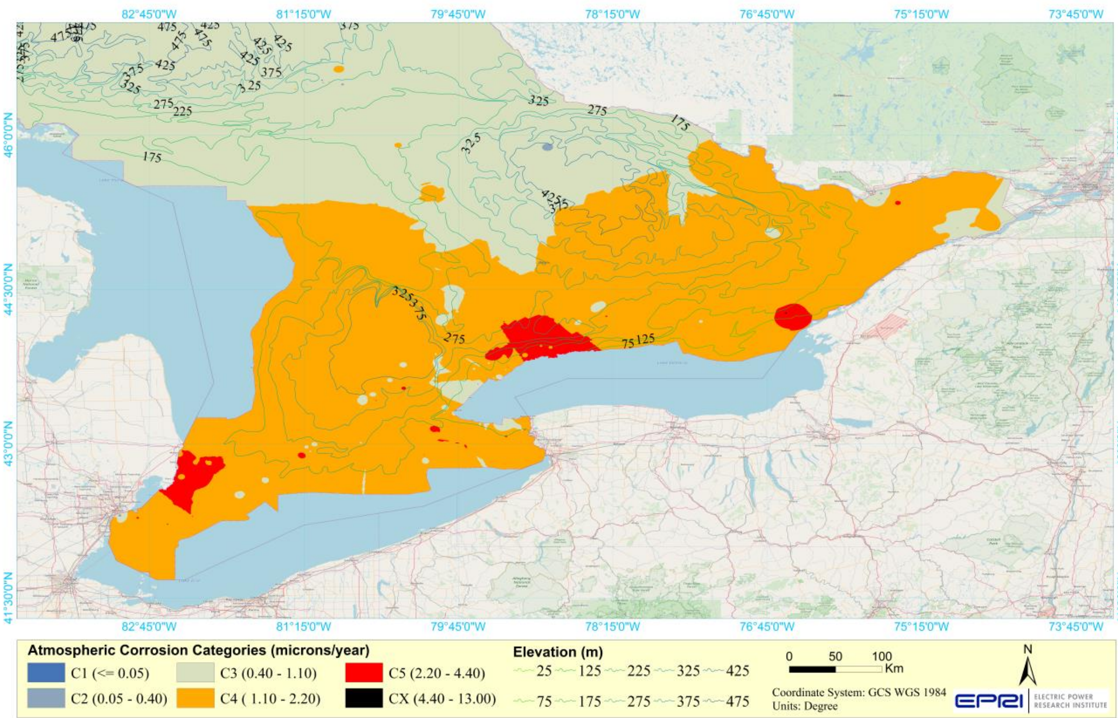

Figure 2: Corrosion zones in Ontario, courtesy of EPRI, 2017

C2 and C3 zones are defined as light corrosion zones and the towers will be protected and maintained in good condition for minimum of 115 years without requiring any 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 is no immediate tower coating needs for structures within these zones.

C4 & C5 zones are defined as heavy corrosion zones which have high and very high corrosion rates, respectively, for zinc and carbon steel. Based on Hydro One asset records, there are approximately 38,800 steel structures in the heavy corrosion zones. The EPRI study analyzed the structures located in C5 zone. The finding was that the structures in C5 zone will, on average, lose their protective zinc 45 years after installation. Furthermore, they would lose 10% of their metal in the following 30 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required. Applying these results to Hydro One's steel tower population, the EPRI study indicated that a significant portion of towers located in high and very high corrosion zones are in need of coating to arrest further deterioration and prevent eventual replacements.

Based on the best available data, 20% of Hydro One's steel structures have been recoated, and 27% have fair/poor condition (23% is in fair, 4% in poor condition), reflecting that the steel structure is experiencing corrosion on the HDG and on the bare steel layer. These structures are targeted for recoating as part of this Investment in order to extend their service life.

C. INVESTMENT DESCRIPTION

Hydro One will continue to coat steel structures that are located in high (C4) and very high (C5) corrosion zones, which meets the coating criteria identified from condition assessment. Currently, there are approximately 38,800 steel towers located within high and very high corrosion zones. Of the 38,800 structures, approximately 13,500 have condition rating indicating that the steel structure has corrosion on the HDG and on the bare steel layer. These structures require recoating to extend their service life.

In light of the foregoing, Hydro One is planning to coat approximately 500 steel structures each year, totalling 2,500 steel structures over the 2023-2027 period. The proposed pacing is consistent with the historical average for this Investment. The Investment's replacement levels for the 2023-2027 period have been summarized in Table 2.

Table 2 - Steel Structure Coating

Steel Structures	Forecast Period				
	2023	2024	2025	2026	2027
Units	500	500	500	500	500
% of Fleet	1.0%	1.0%	1.0%	1.0%	1.0%

D. OUTCOMES

As a result of the Investment, Hydro One will minimize life cycle cost in 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.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - 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.

E. EXPENDITURE PLAN

Table 4 below provides the proposed capital expenditure plan for this investment.

Table 4 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	23.6	24.1	24.5	25.0	25.4	122.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**23.6**	**24.1**	**24.5**	**25.0**	**25.4**	**122.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**23.6**	**24.1**	**24.5**	**25.0**	**25.4**	**122.7**

The factors influencing the cost of the investment include:

- 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 cost more 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;
- Work bundling – it is cheaper to coat towers that are in the same area if some costs can be shared between them; and
- Live-line work (whether work can be performed live-line) – conducting coating without an outage is a major benefit to work scheduling and can optimize resource deployment

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1:

Reactive Replacement of Poor Condition Steel Structures involves reactive responding and replacing corroded steel structures that are in poor condition. This alternative has been 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 ratepayers.

ALTERNATIVE 2:

Coating at Currently Planned Pacing is the selected option. At this pace, poor condition steel structures that are eligible for coating will be coated proactively, in order to maintain long-term reliability and provide maximum economic benefits to ratepayers.

G. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the investment include access to the assets depending on the 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 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 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-06	**TOWER FOUNDATION ASSESS/CLEAN/COAT & LIFE EXTENSION PROGRAM**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	17.3	17.6	17.9	18.3	18.6	89.6

Summary:

This investment involves the refurbishment of steel structure tower members and foundations that due to their poor condition pose an elevated risk of failure. The primary trigger of the investment is deteriorated asset condition. Hydro One is currently focusing on grillage footings and anchors and certain types of towers, which due to their age and material sustain a higher incidence of corrosion and defects. A failed asset creates public safety and system reliability risks. In light of those risks, the investment is aimed to sustain safe and reliable operation of Hydro One's transmission system.

A. OVERVIEW

The scope of this investment includes (i) assessing, cleaning, coating and repairing, as necessary, steel structure tower foundations and (ii) replacing tower members with cracks and/or other defects such as bending, missing or severe corrosion, whose deteriorated condition poses an increased risk of failure (which may include structure collapse in the case of deteriorated tower foundation, and tower arm failure and conductor drop, partial or complete tower collapse in the case of defected tower member). A failed asset poses serious safety risk to Hydro One's employees and general public, especially if an asset fails in a publicly accessible area. A failed asset also poses a system reliability risk that can cause a customer outage.

As part of this investment, Hydro One assesses steel grillage footings to determine if coating or minor repairs can be applied to extend the foundation's service life and where severe corrosion has caused significant strength reduction, the steel foundation will be identified as a candidate for major repair or replacement. Hydro One also assesses tower members and, where appropriate, extends the asset life by adding Z-Brackets on middle arms, replacing the missing, bent or corroded members or, where cracks have been identify, completely replaces tower members.

The proposed investment plan will assess, clean, and coat 819 grillage foundations and 533 towers per year over the 2023-2027 period. Hydro One has evaluated various alternatives, as further described below, and concluded that the proposed pacing of the investment is the most cost effective and efficient undertaking to sustain safe and reliable operation of Hydro One's transmission system.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

(i) Tower Foundation Refurbishment

Foundations support and anchor transmission structures to the ground and enable the structures to withstand the weight of the structure itself, attached components and weather related external forces such as wind and ice. The two dominant foundation types in Hydro One's transmission system are cast-in concrete footings and steel grillage footings. As further explained in TSP Section 2.2, 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). Starting in 1970, Hydro One began using concrete auger type foundation because it allows for construction efficiency and asset durability. It is also compliant with more restrictive environmental protection regulations.

Hydro One is currently focusing on grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. There are approximately 32,500 grillage footings which include approximately 3,300 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 becomes prone to degradation. The majority of steel grillage foundations that are in Hydro One's fleet are older than 50 years, and will need to be assessed.

The need of this investment is determined based on foundation type and consequence of asset failure. Based on field inspection, where severe corrosion has caused significant strength reduction, the foundation will be identified as a candidate for major repair or replacement. The failure of a foundation could directly result in structure failures which may cause a system interruption and employee or public safety incident. Furthermore, damaged foundations could result in very costly repairs or even necessitate the replacement of the entire tower.

Figure 1, Figure 2, and Figure 3 below illustrate damaged grillage footings. The towers eventually had to be replaced due to the damage.

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 Repairs (circuit D2L)

(ii) Tower Member Refurbishment

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. Hydro One has approximately 49,200 lattice steel structures and approximately 1,750 steel poles supporting 115kV to 500kV transmission lines.

The lattice tower is designed and constructed with many individual components and each component plays a role in ensuring the integrity of a structure. If a component is missing or there is a defect, it could impact the tower's integrity and lead to a partially or complete collapse. Hydro One has discovered that certain 230-kV towers in its system 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 on the ground. This issue cannot be left unattended as there are serious safety risks to Hydro One's employees and general public as well as reliability risks. Furthermore, there are many towers with other known member defects that require attention to maintain the integrity of towers.

To mitigate the safety and reliability risks that may result from a failed asset, the identified structures require refurbishment (hanger replacements and/or addition of braces to the top face of the middle arm).

Figure 4: Broken and Cracked hanger examples

Figure 5: Bent Tower Leg (D8S Tower # 347)

C. INVESTMENT DESCRIPTION

As discussed above, the investment covers two programs; the first is intended to inspect, assess, clean and coat the steel grillage footings buried underground, to restore any depleted coating protection and extend the foundations' service life. Hydro One assesses the condition of a tower's foundation and either immediately coats it or schedules future repairs. The decision to coat or repair depends on the severity of the corrosion that is found and the complexity of potential repairs. The Investment also includes minor repairs on damaged footings and identification of footings that need major repair or replacement.

The refurbishment candidates are identified based on results from the assess/clean/coat program. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the components. If metal loss is visible at the time of assessment, the affected components are scheduled for repair or refurbishment.

The proposed plan will assess, clean, and coat approximately 819 grillage foundations per year over the 2023-2027 period. As per Hydro One strategy for steel structures and foundations, assets are prioritized based on line voltage, type of structures and geographic location of the lines. The pacing for assessment, cleaning, and coating of tower foundations for the 2023-2027 period has been summarized in Table 1.

Table 1 - Tower Foundation Assess/Clean/Coat Program

Foundations	**Forecast Period**				
	2023	**2024**	**2025**	**2026**	**2027**
Units	819	819	819	819	819
% of Fleet	1.7%	1.7%	1.7%	1.7%	1.7%

The second aspects of this investment involves the refurbishment of the steel towers with cracked, missing, bent or sever corroded members to restore the integrity. The program will focus on a population of 5000 230KV towers with cracked hangers which have been identified based on tower types and field verifications.

The proposed plan will refurbish approximately 533 towers per year over the 2023-2027 period. As per Hydro One strategy for steel structures and foundations, assets are prioritized based on line voltage, type of structures and geographic location of the lines. Refurbishment levels for the 2023-2027 period have been summarized in Table 2.

Table 2 - Tower Member Refurbishment Program

Foundations	**Test**				
	2023	**2024**	**2025**	**2026**	**2027**
Units	533	533	533	533	533
% of Fleet	1.0%	1.0%	1.0%	1.0%	1.0%

D. OUTCOMES

D.1 OEB RRF OUTCOMES

The investment's objectives are to maintain system reliability and to mitigate employee and public safety concerns by addressing 4,095 grillage foundations and 2,665 steel towers over the five year plan.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - Outcomes Summary

Customer Focus	• Reduce public safety risk associated with steel tower failures • Maintain customer reliability by restoring any depleted coating protection and extend the foundations' service life.
Operational Effectiveness	• Maintain system reliability by restoring any depleted coating protection and extend the foundations' service life. • Proactive foundation assessment and restoration will reduce emergency restoration frequency

E. EXPENDITURE PLAN

Table 4 below provides the Investment's proposed capital expenditures.

Table 4 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	17.8	18.2	18.5	18.9	19.2	92.6
Less Removals	0.5	0.6	0.6	0.6	0.6	2.9
Capital and Minor Fixed Assets	**17.3**	**17.6**	**17.9**	**18.3**	**18.6**	**89.7**
Less Capital Contributions	0	0	0	0	0	0
Net Investment Cost	**17.3**	**17.6**	**17.9**	**18.3**	**18.6**	**89.6**

The factors influencing the cost of the investment include:

- 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 and its foundations;
- Location of the structure: whether it is easily accessible or in a remote/swampy area – accessibility is very important, as having to clear brush and build roads adds significant costs and some work can only be performed under frozen ground conditions;
- Environmental restrictions: whether it 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 to work on towers that are in the same area; and
- The extent of the damage - the damage will determine what kind of equipment is required to perform the repairs.

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1:

Reactive Foundation and Member Replacement involves reactive response and replacement of failed tower foundations, anchors and members. This alternative has been rejected for the following reasons:

- Reactive management of tower foundations, anchors and members would lead to increased asset failures, resulting in elevated safety and reliability risks;
- As tower foundations and anchors deteriorate, emergency restoration and trouble call volumes would be unmanageable;
- Due to the complicated procedure to replace a tower foundation and an arm member, multiple lengthy power outages will be required, which will significantly interrupt the power supply to customers and reduce system operation reliability;
- Cost of replacing a tower foundation could be significantly higher than cleaning and coating the foundation, as more labour and heavy equipment is required.

ALTERNATIVE 2:

Planned Foundation Coating/Repair and Tower Member Replacement is based on assessing, cleaning and coating steel structure foundations and known defected tower members at a rate that is coordinated with the optimal period in the foundation's life cycle at which coating and repair is most beneficial. This alternative would eliminate the backlog of eligible steel structures foundations and towers and reduce long term planned or reactive replacement/repair costs. This alternative is preferred for the following reasons:

1. Poor condition steel structure foundations that are eligible for coating will be coated proactively.
2. Any towers with defected tower members will be refurbished proactively;
3. Risks to transmission system safety and reliability can be mitigated by balancing asset needs, resource availability, and cost impacts.

G. EXECUTION RISK AND MITIGATION

The risks to the completion of this investment include access to the assets depending on the season, availability of qualified resources 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 Program planning phase where all known risks are identified and 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.

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T-SR-07	TRANSMISSION LINE SHIELDWIRE REPLACEMENT
Primary Trigger:	Condition
OEB RRF Outcomes:	Minimize public safety risk associated with shieldwire failures; maintain system and customer reliability by replacing poor condition shieldwire; proactive shieldwire replacement will help to reduce emergency restoration frequency as well as associated costs.

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	12.1	12.3	12.5	12.8	13.0	62.7

Summary:

This investment involves the replacement of shieldwire that are in poor condition based on asset condition assessments. The primary trigger of the investment is the deteriorated condition of shieldwires requiring replacement in order to maintain system reliability and mitigate public safety risks.

A. OVERVIEW

Transmission line shieldwire is a critical component of Hydro One's transmission system that provides lightning protection and grounding continuity to transmission lines. The Transmission Line Shieldwire Replacement Program (the "Investment") replaces transmission line shieldwire assessed to be in poor condition based on Hydro One's condition-based asset management strategy. This information is used to prioritize the replacement of the shieldwire fleet. If the shieldwire is in poor condition and is not replaced in time, there is a very high likelihood that the asset will fail, making contact with the conductor, resulting in a circuit outage and potential customer interruption. Furthermore, broken shieldwire represents a significant safety risk to public and Hydro One's employees as it may fall and swing to the ground. Due to historical construction and demographic patterns, Hydro One is now entering into a period where the shieldwire on many overhead transmission line sections is in poor condition. In order to mitigate reliability and safety risks, the Investment targets the replacement of 305 km of shieldwire per year from 2023 to 2027.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

There are approximately 34,800 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. An example of transmission line shieldwire is presented in Figure 1.

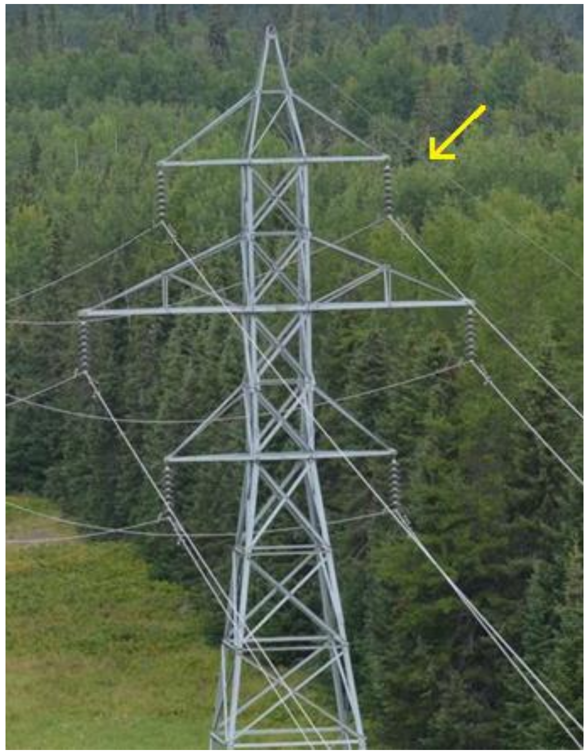

Figure 1: Transmission Line Shieldwire

Shieldwire replacement is condition driven. **Figure 2** below presents shieldwire asset condition information broken down by type currently installed on the Hydro One network. As discussed in TSP Section 2.2, 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 shieldwires that have reached their condition assessment age.

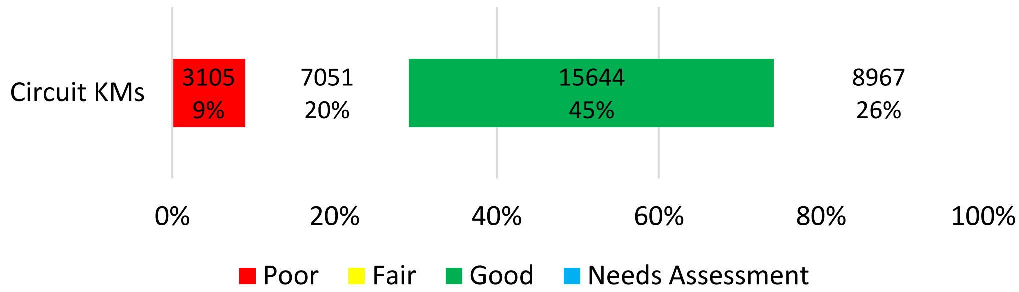

Figure 2: Shieldwire by Type

Shieldwires cannot be maintained or repaired to extend their service life. Rather, Hydro One's shieldwire population is monitored through the condition assessment program and is only replaced once condition warrants. If the poor condition shieldwire is not replaced, it is at high risk of breaking. As broken shieldwire falls, it often makes contact with the conductors below it, causing a circuit outage and decreased reliability to customers. Broken shieldwire that falls in an urban area will also pose a high public safety risk. Broken shieldwire may hit a pedestrian, employee, vehicle or public property as it falls or blows in the wind, and has the potential to cause severe injury and property damage. Examples of shieldwire failure experienced at Hydro One can be found in Figure 3 to Figure 5 below.

Figure 3: 2016 Shieldwire Failure on K2Z

Figure 4: 2016 Shieldwire Failure on D10H

Figure 5: 2017 Shieldwire Failure on S22A

To maintain system reliability and public safety, poor condition shieldwire must be replaced under the Investment. Due to the safety and reliability concerns associated with shieldwire replacement, completion of this Investment is considered a high priority.

C. INVESTMENT DESCRIPTION

As described above, the Investment targets the galvanized steel, ACSR and Copperweld type shieldwires that are in poor condition. Galvanized steel is the most common type of shieldwire currently installed on the Hydro One transmission network. However, this type of asset is no longer being used due to its defects associated with protective zinc coating that deteriorates over time, thereby reducing its mechanical strength and leading to eventual failure. Aluminum cladded steel, also known as Alumoweld, is the most recent type of shieldwire installed on Hydro One's network and is being used to replace shieldwire. In locations where a fibre optic communication channel is required for telecommunication purposes, Hydro One installs OPGW, which consists of Alumoweld shieldwire with a core containing fibre optic strands. ACSR conductors are also installed as shieldwire in limited cases where estimated fault current levels are too high for conventional galvanized steel or Alumoweld wires. Copper cladded steel, also known as Copperweld, is the final type of shieldwire at Hydro One and was previously installed in limited numbers across the network. Copperweld is not capable of adequately sustaining lightning strikes and is therefore targeted for replacement.

The average age of galvanized steel shieldwire is currently 57 years, which is above the 50 year ESL. This type of shield wire currently comprises about 60% of the fleet. Due to historical construction and demographic patterns, Hydro One is now entering into a period where the shieldwire on many overhead transmission line sections is in poor condition. In order to effectively manage these circuits and prevent shieldwire related outages, this Investment targets the replacement of 305 km of shieldwire per year from 2023 to 2027.

The Program's replacement levels for the 2023 to 2027 period have been summarized in Table 1 below.

Table 1 - Shieldwire Replacements

Shieldwire	Forecast Period				
	2023	2024	2025	2026	2027
Units (km)	304	304	304	305	307
% of Fleet	0.88%	0.88%	0.88%	0.88%	0.89%

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.

D. OUTCOMES

Hydro One aims to achieve the following outcomes as a result of the 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.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcomes Summary

Customer Focus	• Reduce public safety risk 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.

E. EXPENDITURE PLAN

As discussed above, the Investment is required to mitigate the safety and reliability risks associated with poor condition shieldwire. Hydro One will strive to complete the Investment in an effective and efficient way to minimize the cost of performing this sustainment task. Typically, the Investment begins in January and ends in December of each of the test years.

Table 3 presents forecasted costs for the Investment. Costs for the Investment are based on an average unit cost estimate calculated utilizing historical replacement costs. The replacement costs are influenced by structure type and accessibility.

Table 3 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	13.1	13.4	13.6	13.9	14.2	68.2
Less Removals	1.0	1.1	1.1	1.1	1.1	5.5
Capital and Minor Fixed Assets	**12.1**	**12.3**	**12.5**	**12.8**	**13.0**	**62.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**12.1**	**12.3**	**12.5**	**12.8**	**13.0**	**62.7**

The factors influencing the cost of the Investment include:

- Shieldwire condition – The cost varies depending on whether the old shieldwire has enough strength remaining to use it when pulling the new wire.
- 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 (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 (whether it's 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 km, to replace a longer line section than it is to a shorter one because mobilization costs are reduced.

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

Reactive Replacement of Failed Shieldwire involves replacing poor condition shieldwire once a failure occurs. This alternative has been rejected because reactive management of shieldwire would lead to an increased number of asset failures and elevated safety and reliability risks. Replacement of shieldwire on an emergency basis will require constant reprioritization of planned work and lead to inefficient redeployment of resources. Reactive shieldwire replacements would also prolong circuit outages and may therefore extend equipment and customer outages.

ALTERNATIVE 2:

Proactive Replacement of Critical Poor Condition Shieldwire is the preferred undertaking as it mitigates reliability and safety risks, as further described above. Shieldwire replacement will be prioritized based upon circuit criticality. Risk mitigation assessments will be conducted to balance shieldwire replacement needs with resource availability and the cost impact to customers. The risk mitigation assessment allows Hydro One to replace poor condition shieldwire in a way that mitigates safety and reliability risks while balancing the asset needs, resource availability and the cost impact to customers.

ALTERNATIVE 3:

Proactive Replacement of All Poor Condition Shieldwire involves planning for the replacement of all backlogged shieldwire previously confirmed to be in poor condition and all shieldwire that is expected to reach poor condition during the five year period. Condition assessment conducted during the five year period will reveal additional sections of shieldwire that have reached poor condition and require replacement. This alternative will ensure that these sections of shieldwire are replaced within the five year period, regardless of criticality. In addition to both the critical and non-critical sections of recently identified poor condition shieldwire, all backlog shieldwire previously identified as having reached poor condition will also be replaced. This alternative will address all confirmed poor condition assets and result in the elimination of the backlog of poor condition shieldwire. This alternative was rejected to account for bill impacts and risk mitigated based on the funding required.

G. 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, refurbishments are planned and material is ordered approximately one year in advance.

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T-SR-08	TRANSMISSION LINE INSULATOR REPLACEMENT
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Public Policy Responsiveness, Operational Effectiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	$78.4	$78.1	$79.5	$81.0	$82.5	$399.5

Summary:

Transmission Line Insulator Replacement investment involves primarily the replacement of defective porcelain insulators manufactured between 1960 and 1982, at an annual rate of approximately 3,980 circuit structures per year. This rate has been consistent since the last Transmission application, but the range of targeted insulators has been expanded to include insulators manufactured between 1960 and 1965 because of recent failures. Hydro One retained the Electric Power Research Institute (EPRI), to assess the condition of these porcelain insulators and the results obtained by EPRI support immediate replacement. As part of this investment, Hydro One plans to replace insulators in publicly accessible (critical) areas by 2023 and defective insulators in other locations planned for replacement by 2028. Hydro One will also replace certain deteriorated polymer insulators on an “as-needed” basis.

A. OVERVIEW

The Transmission Lines Insulator Replacement investment (the "Program") primarily involves the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1960 and 1982. These defective insulators are 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.

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 immediate 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.

A sample of pre-1965 insulators were also assessed by EPRI at the time of the original study, which showed satisfactory results for 1950's models, but poor results for insulators made in 1960 and beyond. This result, combined with recent failures of insulators manufactured in 1962 and 1963, led Hydro One to extend the range of manufacture dates for insulator replacements to 1960-1982. Use of this date range will remove all defective COB/CP insulators from the Hydro One transmission system.

[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.

This Program will also address the replacement of deteriorated polymer insulators. Polymer insulators in 230 kV 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, which 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.[2] 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 230 kV insulators which show extensive degradation from service as soon as possible due to high risk of failure. Other types of 230 kV 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 on an "as-needed" basis.

Program pacing is mainly influenced by the number of defective porcelain insulators located in publicly accessible (critical) locations. Publicly accessible (critical) locations include structures located near roads, water, railways, urban areas, golf courses, and educational and health care facilities. As part of this investment, Hydro One plans to replace insulators in publicly accessible (critical) areas by 2023, with the remaining defective insulators in other locations planned for replacement by 2028. The rate of the replacement will be approximately 3,980 circuit structures per year for the remaining duration of the program, which continues the same pacing established in the most recent Transmission application.

[2] EB-2019-0082 TSP Section 1.4 Attachment 11, EPRI Polymer Insulator Population Assessment.

B. NEED AND OUTCOME

B.1 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 in Figure 1 while an individual insulating unit (i.e. skirt, disk, shell) is shown in Figure 2.

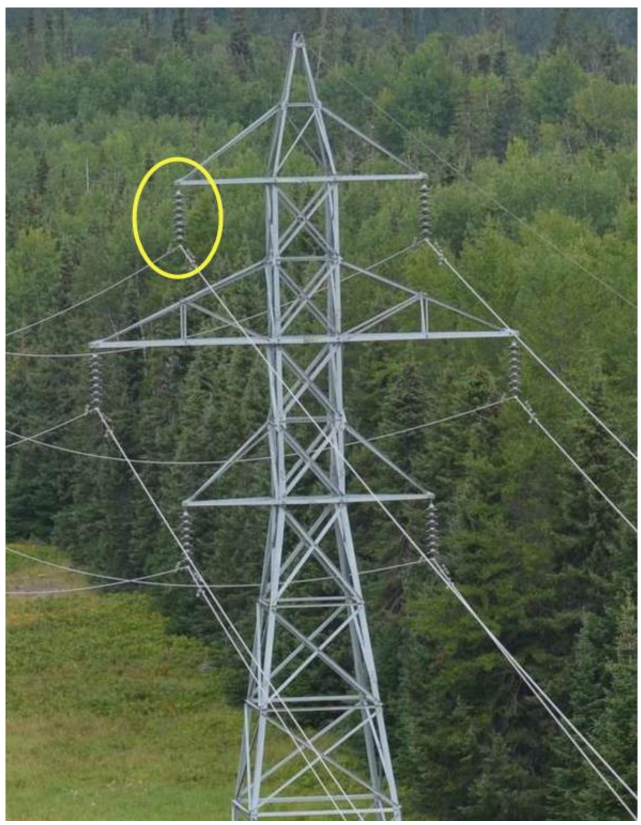

Figure 1: Transmission Line Insulator String

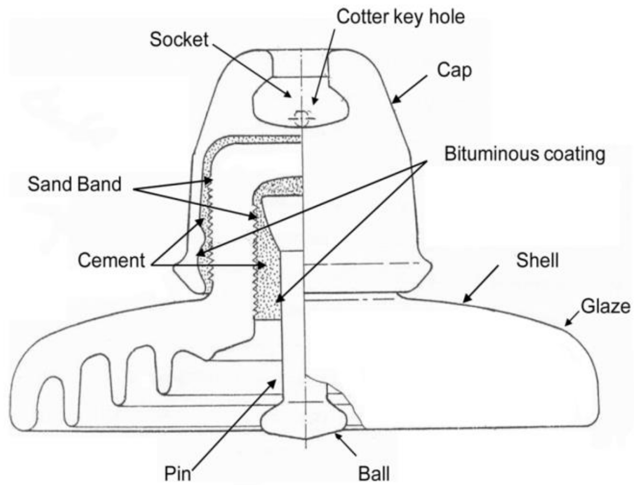

Figure 2: Transmission Line Insulator Unit

There are approximately 437,000 insulator strings[3] in Hydro One's overhead transmission network. As described in TSP Section 2.2.3.4, 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 - Percentage of Insulators by Material

Insulator Type	Quantity (Circuit Structures)
Porcelain	71,675
Glass	35,838
Polymer	11,946
Total	119,459

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 longer than the transmission lines they serve. However, porcelain insulators manufactured by Canadian Ohio Brass and Canadian

[3] An insulator string is a series of insulators strung together. The number of insulators that comprise an insulator string is variable.

Porcelain between 1960 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 1960s 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

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 in excess of 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, it is a physical breakage of the insulator which may result in a conductor falling to the ground. The mechanical failure poses 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. Photos of this incident are shown in Figure 4 and Figure 5 below. Similarly, in January 2017, an insulator on circuit HL3 mechanically failed causing the conductor to fall over a roadway in Hamilton. A photo of this incident is shown in Figure 6 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 is significant, averaging 37 hours, depending on the location and severity of the failure.

Figure 4: V76R Insulator Failure

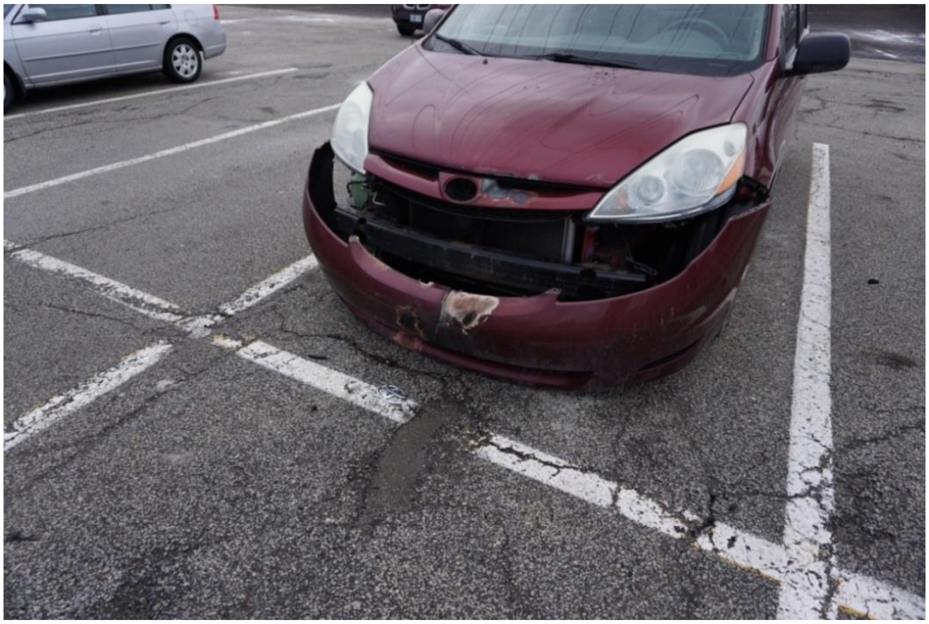

Figure 5: Damage Caused by V76R Insulator Failure

Figure 6: HL3 Insulator Failure

The porcelain insulators manufactured by COB and CP are used province-wide in Hydro One's transmission system. There are approximately 37,000 circuit structures with defective porcelain insulators and roughly 17,000 have been identified as being in publicly-accessible (critical) locations. Publicly-accessible (critical) structures include those located near roads, water, railways, urban areas, golf courses, and educational and health care facilities. To date approximately 16,500 publicly-accessible COB and CP insulators have been replaced. A breakdown of the defective population in relation to the total insulator population as of 2020 year-end can be seen in Figure 7 below.

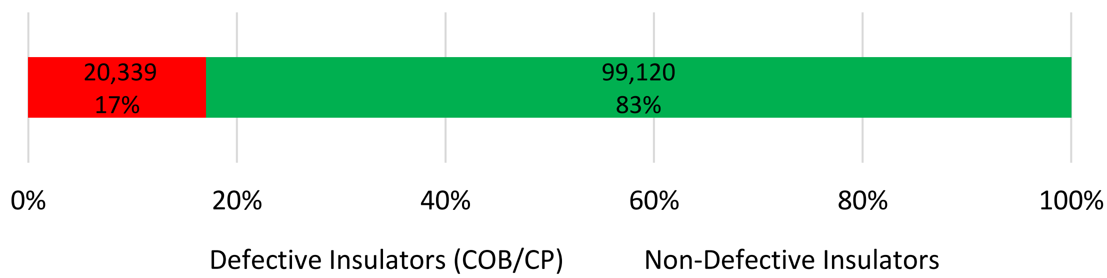

Figure 7: Insulator Fleet Condition Status (2020 YE)[4]

Figure 8 illustrates the number of COB and CP failures over the past ten years, showing an increasing trend. The number of failures is expected to rise due to the degradation of the known defective COB and CP porcelain insulators, potentially impacting public safety, system performance and customer reliability. As noted above, electrical failures typically result in outages requiring significant repair time.

[4] Hydro One is in the process of identifying the number of poor condition polymer insulators.

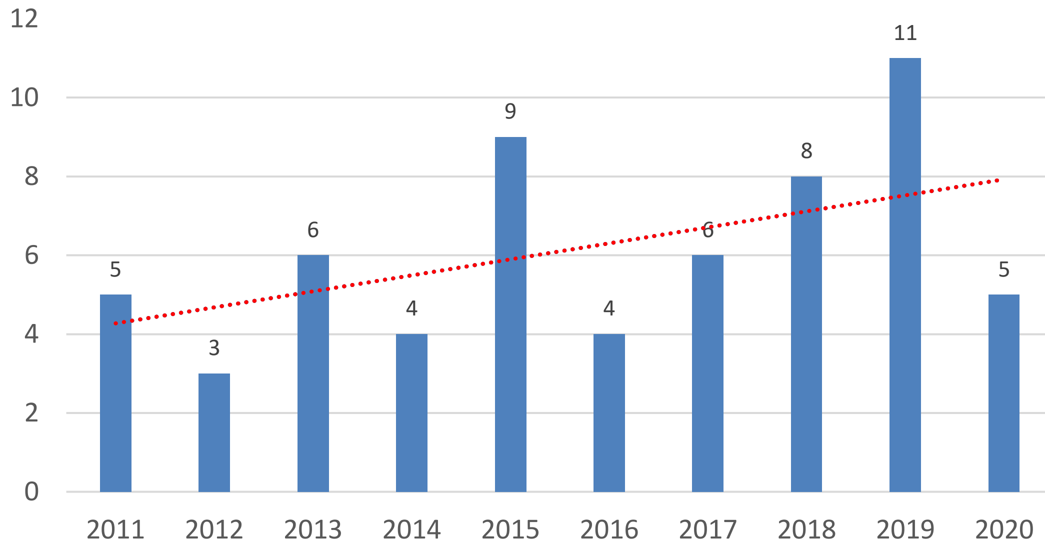

Figure 8: Frequency of COB/CP Insulator Failures

To address concerns associated with defective porcelain insulators, Hydro One retained, EPRI, a third party expert to perform laboratory testing on COB and CP porcelain insulators to assess their condition and assist Hydro One in determining the pacing of porcelain insulator replacement. The testing program comprised two phases.

Phase one was completed in 2016[5] 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 urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed in publicly-accessible (critical) structures where public safety could be at risk. Based on the phase one results, Hydro One significantly increased the insulator replacement rate, compared to pre-2016 levels, and prioritized the replacement of insulators in publically accessible (critical) locations.

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[5] 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

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.

Although the sample of insulators tested was not sufficient to perform a rigorous statistical analysis upon which to base recommendations, the results strongly suggested that the installed population of CP and COB insulators manufactured between 1965 and 1982 had reached or was reaching end of useful life.

Phase two of the testing was performed in 2017.[6] 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 under steep transient voltages (e.g. lightning);

[6] EB-2019-0082 TSP Section 1.4 Attachment 12, EPRI - Phase 2: CP/COB Porcelain Insulator Population Assessment

- TMC drastically decreases the 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. 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.

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 majority of conductor drops recently experienced on Hydro One’s porcelain insulated transmission system failed due to mechanical failure.

The phase one and two 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 provided by EPRI is that the identified population of COB and CP insulators should be removed from service as soon as practically possible.

DETERIORATED POLYMER INSULATORS

Hydro One uses polymer insulators on the 115 kV and 230 kV transmission system. Polymer insulators have an Expected Service Life[7] (ESL) of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s have reached their ESL and need to be evaluated for replacement. First-generation polymers are more problematic when 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 generation polymer insulators use modified designs and refined manufacturing techniques.

Furthermore, 230 kV 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. The need to address the polymer insulator issue is underscored by two failures which occurred in October and November 2016. Both failures were a result of 230 kV polymer suspension insulators on C28C failing mechanically resulting in a conductor drop, as shown in the photos in Figure 9 and Figure 10. The dropped conductor did not contact the ground but was held in the structure window.

[7] Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions.

Figure 9: Failed Polymer Insulator

Figure 10: Failed Polymer Insulator

Since portions of Hydro One's polymer insulator population are 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 focused on 87 polymer insulators from various manufactures with a service life range of 13 to 26 years. The following three insulator configurations form the scope of the study:

- 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.

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.

The following are the key findings of the EPRI condition assessment analysis:
Visual inspection showed that:

- The 230 kV NGK insulators installed with 8-inch corona rings are experiencing rubber housing damage at the line-end. Currently this deterioration does not appear overly serious, but it is not known how quickly the housing deterioration will progress. In the EPRI aging chamber and at one EPRI member utility site this deterioration did result in eventual failure.
- The 230 kV K-Line insulators with the 4-inch donut corona ring have an extremely high likelihood of electrical and/or mechanical failure due inadequate control of the electric field on the surface of the rubber housing at the line-end. The rubber housing at the line-end of these insulators has been severely eroded leading to exposure of the fiberglass rod. Such exposure of the rod will result in either mechanical or electrical failure with a high probability of the insulator parting and causing a conductor drop. Smaller (4-inch) corona rings were used on earlier generations of polymer insulators. When older polymer insulators were designed and manufactured, the long-term effects

of electric fields were not well understood and it was standard practice to use small or no corona rings which caused unexpected polymer degradation. Newer generation polymer insulators use modified designs and refined manufacturing techniques.

- The 230 kV NGK insulators installed without corona rings are showing signs of serious deterioration of the line-end rubber housing and deterioration of the secondary seal. As such, they are considered to have a high risk of failure.

Dye penetration testing showed that:

- Each of the insulator groups with the exception of the Ohio Brass insulators had a single insulator unable to meet the dye penetration test requirements.

Water vapor ingress testing showed that:

- Seven 230 kV K-Line insulators exhibited low resistance along their length after humidity conditioning. Of these seven, three had damage from power arcs and housing erosion which may explain their failure.

End-fitting moisture penetration tests showed that:

- All but three insulators passed the test. Of the failing three units, two have been in service for 26 and 27 years, and the third had major line-end rubber erosion and rod exposure.

At the conclusion of its condition assessment analysis, EPRI provided Hydro One with its recommendations. Key EPRI recommendations are as follows:

- All 230 kV 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 230 kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.
- All the 230 kV Ohio Brass 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.

Hydro One is using this information to optimize the overall replacement program based on the risk of in-service failure. Considering the study results, Hydro One is currently in the process of identifying the number of impacted polymer insulators and will incorporate the following recommendations into the existing 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
- Continue to monitor 230kV insulators fitted with 8-inch corona rings for signs of degradation.

C. INVESTMENT DESCRIPTION

Transmission line insulators cannot be maintained or repaired to extend their service life; therefore, defective porcelain insulators and deteriorated polymer insulators are targeted for replacement as part of the Program. The defective porcelain insulators will be replaced with either glass or coated glass type insulators. Replacements of defective porcelain insulators will be prioritized to address locations posing a higher public safety risk. The deteriorated polymer insulators will also be replaced with either glass or coated glass insulators. Due to their longer ESL, glass insulators are preferred and are used wherever practical. However, polymer coated glass insulators will be considered when their coating properties offer benefits (i.e. in areas with high contamination).

The Program's replacement levels for the 2023-2027 period have been summarized in Table 2.

Table 2 - Insulator Replacements

Insulators	Test				
	2023F	**2024F**	**2025F**	**2026F**	**2027F**
Units	3,980	3,980	3,980	3,980	3,980
% of Fleet	3.3%	3.3%	3.3%	3.3%	3.3%

D. 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.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - Outcomes Summary

Customer Focus	• Eliminate public safety risk associated with defective porcelain insulators • Maintain system and customer reliability by replacing defective and end-of-life insulators.
Operational Effectiveness	• Maintain system and customer reliability by replacing defective and end-of-life insulators.

E. EXPENDITURE PLAN

As discussed above, the investment is primarily needed to replace the defective COB and CP porcelain insulators that pose significant public safety and system reliability risks. Hydro One will strive to complete the Program in an effective and efficient way to minimize the cost of performing this sustainment task. The Program starts in January and ends in December of each of the test years.

Table 4 below summarizes historical and projected spending on the aggregate investment level.

Table 4 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	85.3	84.8	86.4	88.0	89.6	434.1
Less Removals	6.9	6.7	6.9	7.0	7.1	34.6
Capital and Minor Fixed Assets	**78.4**	**78.1**	**79.5**	**81.0**	**82.5**	**399.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**78.4**	**78.1**	**79.5**	**81.0**	**82.5**	**399.5**

F. ALTERNATIVES

Hydro One considered the following alternatives before proceeding with *Planned Insulator Replacement* (Alternative 2).

ALTERNATIVE 1: STATUS QUO

The Status Quo 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 in a public area. 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.

G. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the insulator replacement program include: outage constraints, resource 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.

T-SR-09	TRANSMISSION STATION DEMAND AND SPARES AND TARGETED ASSETS
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	43.9	44.7	45.2	46.2	47.0	226.8

Summary:

This investment involves procuring spare transmission station equipment and securing the resources required for (i) emergency replacements of transmission station equipment that has failed while in service and (ii) replacements of deteriorated assets that are not addressed through station-centric investments. The purpose of the investment is to ensure that Hydro One maintains an adequate inventory of spares for its transmission station assets in order to facilitate the expedient replacement of a failed or deficient component at a transmission station, and that Hydro One continues to comply with its legal obligations while mitigating safety, system reliability, and environmental risks that an unforeseen failure might cause.

A. OVERVIEW

The Transmission Station Demand and Spares Investment (the “Investment”) is a reactive program that is primarily designed to prevent, immediately respond to, or minimize the effects of an emergency situation. The Investment involves the procurement of spare transmission station equipment such as transformer operating spares, circuit breakers, instrument transformers, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, and protection, control, and telecom equipment. The Investment covers the resources required for (i) emergency replacement of transformers and other minor station equipment that have failed or shown signs of deterioration while in service and (ii) replacements of deteriorated assets that are not addressed through station-centric investments. It also includes the necessary design, construction, and commissioning resources to replace failed station equipment in a timely manner.

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 a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating, and reliability criteria and standards administered by the IESO and the Transmission System Code (TSC). The Investment ensures that Hydro One continues to comply with its legal obligations while mitigating safety, system reliability, and environmental risks that an unforeseen failure might cause.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

Hydro One operates one of the largest transmission systems in North America. As a critical asset for Ontario, Hydro One’s transmission system extends to most of the province, and encompasses diverse geographic and climactic conditions. It is part of the Bulk Electric System (BES), which is subject to the reliability standards established by the North American Electric

Reliability Corporation (NERC) that ensure the integrity of the interconnected North American BES. Transmission stations are a key category of infrastructure that is critical to the functioning of the transmission system. The major components of transmission stations include power transformers, circuit breakers, disconnect switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, protection and telecom systems, site infrastructure, and buildings.

If a transmission station asset fails or is in imminent danger of failure, it is critical for Hydro One to be able to perform the emergency replacement of that asset as soon as possible, so as to ensure the integrity and reliability of the transmission system. When a transmission station asset fails, the impact varies depending on the location of the component and level of redundancy (if any) built into the station's electrical configuration. In a best-case scenario, transfer capability could be reduced even though the customer will not see any interruption. But 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 transmissions station assets might pose safety or environmental risks.

The Investment ensures that Hydro One maintains an adequate inventory of spares for its transmission station assets in order to facilitate the expedient replacement of a failed or deficient component at a transmission station. These assets might include transformers; power equipment; ancillary equipment; protection, control, and telecom equipment; and other minor equipment.

The reliability framework for Ontario's electricity transmission system is based on the reliability standards established by NERC, which have been adopted in Ontario and are enforced by the IESO. The IESO has established load restoration criteria for high-voltage supply to a transmission customer. In accordance with Section 7.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria* (ORTAC), Hydro One is required to restore an affected load within the following restoration times:

- All load must be restored within approximately 8 hours.
- When the amount of load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately 4 hours.
- When the amount of load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes.

Furthermore, the OEB's *Transmission System Code* (TSC) sets out, among other things, the minimum requirements that a transmitter must meet in maintaining its transmission system. Under Section 5.4 of the TSC, during an emergency or in order to prevent or minimize the effects of an emergency, Hydro One is required to take immediate action to ensure public safety; to safeguard life, property, or the environment; and to protect the stability, reliability, or integrity of Hydro One's transmission facilities. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating, and reliability criteria and standards imposed by the IESO and the TSC.

In light of the foregoing, to maintain system reliability and prevent load interruption to customers, Hydro One needs to maintain a stock of a spare transmission station equipment (e.g., transformers, circuit breakers, instrument transformers, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, and protection, control, and telecom equipment) and must have the sustained ability to respond immediately to an emergency situation or to prevent or minimize the effects of an emergency.

C. INVESTMENT DESCRIPTION

As Hydro One's transmission station equipment deteriorates, the probability of failure increases, requiring resources and funding to be available to respond to these failures. In light of the foregoing, the Investment includes the procurement of spare transmission station equipment such as transformer operating spares, circuit breakers, instrument transformer, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, and protection, control, and telecom equipment. The Investment also covers the resources required for emergency replacement of transformers and other minor station equipment that have failed while in service. This includes the necessary design, construction, and commissioning resources to replace failed station equipment in a timely manner to ensure compliance with standards imposed by the IESO and the TSC.

The bulk of the Investment comprises the spare transformer inventory. Hydro One uses a Markov model to determine the appropriate number of spare transformers required to ensure continuity of electricity supply to customers, safety, and reliability. The Markov model uses the probability of failure, carrying costs, and procurement lead time to determine the most cost-effective number of spares to be kept in inventory. As described in 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.[1] EPRI concluded that Hydro One's operating spare transformer analysis using the Markov model is appropriate. Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost-efficiency.

The Investment also includes activities related to replacing poor condition assets – i.e., poor condition assets that have yet to fail but warrant replacement in a timely manner. These targeted replacements are planned where there is no integrated station replacement project to address the replacement. This program mainly focuses on smaller equipment – i.e., switches, instrument transformers, batteries, station service ancillary, etc.

D. OUTCOMES

The Investment aims to maintain reliable supply to customers by replacing failed station equipment in a timely manner and mitigating safety and environmental risks. It will allow Hydro

[1] EB-2019-0082, TSP Section 1.4, Attachment 5.

One to replace failed station equipment as promptly as possible to restore the system to normal operating conditions, which will ensure compliance with Hydro One's regulatory obligations.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Table 1 - 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.
Operational Effectiveness	• Maintain transmission system reliability and safety. • Reduce safety risks associated with failing equipment.
Public Policy Responsiveness	• Ensure Hydro One meets its compliance obligations with respect to power system restoration and reactive response.

E. EXPENDITURE PLAN

Table 2 below summarizes projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	45.6	46.5	47.0	48.0	48.8	235.9
Less Removals	1.8	1.8	1.8	1.8	1.9	9.1
Capital and Minor Fixed Assets	**43.9**	**44.7**	**45.2**	**46.2**	**47.0**	**226.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**43.9**	**44.7**	**45.2**	**46.2**	**47.0**	**226.8**

F. ALTERNATIVES

The 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 result in non-compliance with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and/or the TSC. It could also negatively impact customer operations and customer service. For example, the lead time to procure a new transformer can be a year or more. As a result, failing to have adequate spare transformer inventory on hand would introduce lengthy replacement timelines and negatively impact system reliability.

G. EXECUTION RISK AND MITIGATION

The risks of potential customer supply interruptions and longer outages caused by a failed transformer must be mitigated by timely response, which will be unplanned and reactive by definition. There are risks to executing such unplanned work including the availability of resources and long lead times for the purchase of new transformers. 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.

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T-SR-10	PROTECTION RELAY REPLACEMENT PROGRAM
Primary Trigger:	Obsolescence
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	8.8	8.9	9.0	9.1	9.2	44.8

Summary:

This investment involves the replacement of protection systems that pose a high risk of causing delivery point interruption and impacting the reliability of transmission network and connection stations. This investment is required to mitigate system reliability and safety risks and to ensure regulatory compliance with NERC and NPCC standards.

A. OVERVIEW

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 could 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 transmission network stations and connection stations.

The bulk transmission system is the "backbone" of Ontario's electricity system. Bulk power flows through the 500kV, 230kV, and 115kV transmission systems. Protective relays and associated systems maintain system reliability by protecting supply within Ontario's bulk transmission system and mitigate the potential impact of abnormal conditions to the rest of the interconnected grid. Through its bulk transmission system, Hydro One serves the largest electricity generators and industrial end-users as well as majority of Ontario's Local Distribution Companies (LDCs), all of whom are directly affected by the reliability and performance of Hydro One's transmission system.

Transmission connection stations step down power from higher voltages to lower voltages to facilitate the distribution of power via the downstream distribution network. Through these stations, Hydro One supplies power to critical infrastructure such as telecommunications systems, water and wastewater treatment facilities, hospitals and other health care facilities, airports and transportation systems, schools and universities, financial services systems. It is of paramount importance to ensure that Hydro One's transmission system operates reliably.

The Protection Relay Replacement investment (the "Investment") is a program that involves the replacement of protection systems operating beyond their Expected Service Life (ESL). Hydro One uses the ESL of relays as a trigger for protection system replacement assessment to investigate the health or condition of a relay and the risk of its potential failure with respect to reliability and safety. With respect to priority of protection replacements, Hydro One targets protection systems that have had high failure rates as well as assets located at critical transmission network and connection stations. Since the condition of this class of asset cannot be easily monitored, Hydro One uses the following additional factors in deciding whether to replace the asset: 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), and the inability to comply with current reliability standards.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

As discussed in TSP Section 2.2, Hydro One has a thorough and ongoing asset management process that involves monitoring and reviewing transmission assets and assessing their condition. Hydro One's strategy for protection relays and protection schemes is to maintain system reliability by ensuring the correct protective operation is initiated to isolate a faulted asset from the system. Hydro One proactively inspects and monitors the protection systems, tracks their failure rates, misoperations and manufacturers' support. This allows Hydro One to manage maintenance needs and assess the protection systems' condition as a factor to determine the need for asset replacement.

Hydro One's strategy for protection systems is to replace systems that have a high likelihood of causing delivery point interruption and impacting the reliability of transmission network and connection stations. Assessments to repair or replace protection systems are done on an individual basis. The assessment is based on risks identified from demographics, condition, safety, technology obsolescence, innovation, utilization, and costs comparison between refurbishment and replacement. Units in poor condition, known manufacturer defects/obsolesce, or anticipated higher repair costs are prioritized for replacement.

As discussed above, protection system equipment is activated only when there is a fault or other power system problem. A fault or system disturbance can result in equipment damage, personnel exposure to hazards, wide area disturbances and prolonged customer outages. Protection system misoperations provide an overall indication of the protection system's health. It is the most important indication of the protection system performance. Hydro One tracks the performance of the protection system by analyzing every protection system operation to determine if it operated as expected. 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 in the mitigation or elimination of the issue.

Hydro One currently has 12,494 protection systems in-service. As further described in TSP Section 2.2, there are three vintages of protection systems that can be found in Hydro One's transmission system: Electromechanical, Solid State and Microprocessor. Approximately 27% of the protection system population is operating beyond its ESL. Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. Table 1 below presents a summary of Hydro One's protection systems broken by technology type that operate beyond its ESL. Based on Hydro One's and industry's experience, once the protection system reaches its ESL, the risk of failure is significantly elevated**.** It is increasingly challenging to predict the time of failure with certainty as most of the systems and their components do not show signs of wear and fatigue. They usually operate until they suffer an abrupt failure. On average, 94% of station protection and 89% of line protection misoperations are related to hardware failures associated with protection systems.

Table 1 - Summary of the ESL of Hydro One's Protection Systems by Technology*

Protection Type	Quantity	Avg. Age (Years)	ESL (Years)	Beyond ESL* 2020	
				Qty.	% of Type
Solid State	1,784	36.5	25	1,618	91%
Electro-mechanical	3077	40.1	45	1,359	44%
Microprocessor	7,633	8.8	20	420	6%
TOTAL	12,494	20.5		3,397	27%

** Data current as of December 31, 2020*

A challenge associated with protection systems is vendor support. For example, as can be seen in Table 1 above, over 90% of the solid-state fleet of protection systems are operating beyond their ESL. Because this equipment is obsolete, Hydro One has little or no support from its vendors when it comes to service, replacement units or provision of spare parts. When a device operates beyond its ESL, the risk of failures is elevated. It even further elevates when there is no vendor support, including supply of spare parts and/or firmware and engineering support. This might impact restoration time of the outage, caused by faulty, obsolete protection system, as the repair time will be longer. The repair might include the installation of a new device based on different technology which will require further reengineering and construction work.

C. INVESTMENT DESCRIPTION

The Investment involves a series of individual investments. Over the rate term, Hydro One is planning to replace approximately 210 protection relays at various transmission network and connection stations. The protection systems identified for replacement have reached their ESL, have shown increasing failure rates, have limited or no manufacturer support and can no longer reliably perform their intended function due to equipment technological advances.

D. OUTCOMES

As a result of the Investment, Hydro One anticipates the following outcomes:

- **Safety** – replacement of ESL and obsolete protection system will mitigate employees' and public safety risk. 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 the protection system 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 may be presented as a result of protection system failure or misoperation.
- **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. Old 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.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcomes Summary

Customer Focus	• Maintain reliability performance of bulk electricity system power flows through the replacement of ESL protection systems.
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
Financial Performance	• Realize cost savings by addressing multiple degrading components within the station as part of the same project.

E. EXPENDITURE PLAN

As discussed above, the Investment is needed to replace the protection systems at network and connections stations which may compromise the reliability of supply due to the high risk assets that have reached their ESL. Hydro One planned the Investment in a way that strives to complete it as effectively and efficiently as possible so to minimize the cost of performing this sustainment task.

Table 3 below summarizes projected spending on the aggregate investment level.

Table 3 - Total Investment Cost

($M)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	8.8	8.9	9.0	9.1	9.2	44.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**8.8**	**8.9**	**9.0**	**9.1**	**9.2**	**44.8**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**8.8**	**8.9**	**9.0**	**9.1**	**9.2**	**44.8**

The factors influencing the cost of the investment include:

- Applicability of NERC and/or NPCC requirements
  - Replacement of protection and automation systems must comply with applicable NERC/NPCC which has significant increase on costs. When protection/control

    - equipment is replaced, if applicable to the given elements in the station, the systems must be designed to meet the applicable NERC and/or NPCC requirements (for example redundancy of protection systems, AC and DC supply, physical and diverse separation of equipment).
- Need for additional civil infrastructure such as cable trenching, and/or ducts
    - This could include physical separation of A & B communication paths which have a significant increase on costs. This requirement is mandated by the applicable NPCC design criteria.
- Available space within the control building or relay room to facilitate upgrades
    - New location will require additional facilities to be installed to connect the equipment rather than re-using existing facilities (i.e. relay room rack space), increases cost. The lack of space or additional cabling in cable pans could trigger a new relay building.
- Complexity of stages and outages required to facilitate work
    - Increases planning costs portion of the project, and
    - Increases overall duration of project (interest and overhead costs increases)

F. 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.

- Assets in deteriorated condition will continue to deteriorate, thereby increasing the likelihood of unexpected failures. These failures might be prolonged and might result in extended equipment and customer outages which will subsequently lower 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 constantly 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.
- 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

This is the preferred investment option. It involves proactive replacement of protection systems and associated ancillary equipment 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 bulk electricity system. Because it is not easy to monitor the condition of all 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. 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 ultimately can result in significant injuries or even death. 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.
- 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 integrated protection and automation system which lead to incompatibility of the existing protection hardware with the associated devices.

- Technology 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 the most cost effective manner.

G. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of protection systems replacement projects are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory 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 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, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	19.5	29.4	29.2	27.6	8.3	114.0

Summary:

This investment involves the replacement of Hydro One's Synchronous Optical Network (SONET) system with a new packet-based system. The primary trigger of the investment is technological obsolescence of the legacy SONET system. The investment is expected to improve reliability of Hydro One's power system telecom system serving teleprotection and supervisory control systems.

A. OVERVIEW

Legacy SONET System Replacement (the “Investment”) 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 based on SONET technology which is primarily utilized for Protections and 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, and is used to provide backhaul communications for the provincial mobile radio system.

A significant portion of Hydro One’s SONET system, which primarily includes multiplexer equipment at transmission stations, is currently beyond ESL and is facing technological obsolescence based on the factors listed below:

- Large segments of the system have exceeded their expected service life (ESL),
- Technological obsolescence as vendors withdraw support (end of vendor support), and;
- Increasing challenges and lead times to procure SONET equipment spares.

When end of vendor support (EVS) is reached, spare parts become increasingly harder to procure, which leads to repairs and maintenance becoming increasingly costly and challenging, 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 EVS.

Other factors include:

- The first generation of SONET system equipment account for the majority of SONET equipment failures.
- This system is critical for the operation of the grid and equipment failures have a high reliability impact.
- Accelerated rate of failures in the future could require replacement volumes that would be impossible to execute due to a very large installed base.

Failures caused by SONET equipment have resulted in multiple power system telecom services being rendered unavailable until repaired. Loss of communication channels 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, transformers etc. from service. In turn, these actions can result in a negative impact to the reliability of the transmission system, and potentially expose customers to a less reliable configuration due to reduced system reliability. To address the reliability issues associated with the obsolescence of the technology and network equipment on which SONET is built, Hydro One has developed the Investment, which aims to replace the legacy system with a modern solution. Hydro One has evaluated various alternatives for the Investment as described below, and concluded that proactive replacement of the legacy system with new packet-based technology is the most cost effective and efficient undertaking. The projected cost of the Investment is estimated to be $114M over the 2023-2027 test period.

B. NEED AND OUTCOME

B.1 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 a fault condition 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 Ontario Grid Control Centre (OGCC) through the SONET network.

Protection trip signals, also known as tele-protection signals, along with other data traffic, are multiplexed, using time-division multiplexing (TDM), to higher bandwidth signals by SONET add-drop multiplexers on the network providing reliable and robust communications between Hydro One facilities. The SONET network multiplexer equipment is composed of two vintages; the first generation initially deployed between 1998 and 2007 and the second generation 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 network that are made up of microwave links as opposed to fibre connected paths. Although they were economical at the time of SONET deployment, 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.

To assess asset condition, Hydro One takes into account asset age vs. ESL, rate of failures, reliability risk, vendor support, manufacturer recommendations and historical asset retirements. In addition, 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*
SONET Communication Network	Multiplexers	267	15	125
	Digital Radios	22	15	22
	Optical Amplifiers	32	15	23
	48 VDC Batteries	272	10-20[1]	25
	48 VDC Chargers	270	20	71

** Data as of December 2020*
[1] Varies based on equipment make and/or model

The first vintage of multiplexer equipment has reached its ESL and is facing technological obsolescence as vendors withdraw support and, as such, spare parts have become increasingly hard to source. The majority of SONET equipment failures are associated with the first vintage of multiplexer equipment (Vintage A MUX) as shown in Figure 1 below. These failures have resulted in multiple power system telecom services being rendered unavailable until repaired. With the loss of communications channels, protection systems dependent on communications cannot ensure the power equipment is adequately protected and the OGCC can lose visibility into the status of the equipment and system power flows. In turn, these conditions result in negative impacts to system reliability and expose Hydro One and its customers to reduced SONET system reliability, which can lead to equipment being forcibly removed from service.

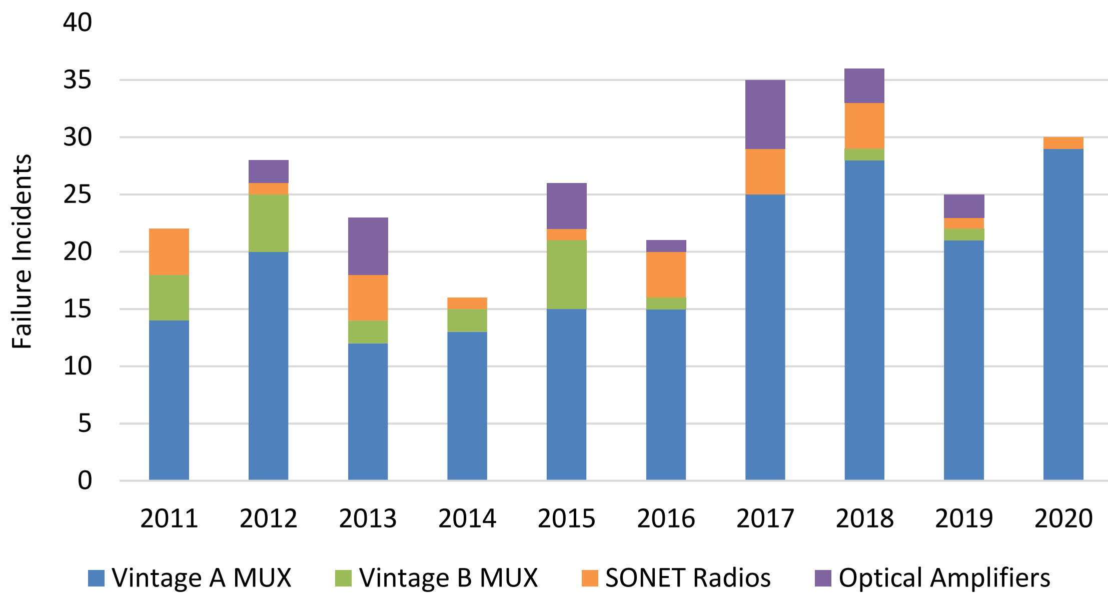

Figure 1: Failure Incidents for SONET Equipment

C. 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. Implementation in the short and mid-term will begin with the replacement of legacy SONET equipment on Rings 1-9 taking into account other telecom sustainment needs and direction of the strategic expansion of the network. More specifically, the Investment will replace the first vintage of SONET multiplexers that have been in service for close to 20 years with a solution based on Multiprotocol Label Switching (MPLS) technology at over 70 stations. The Investment's scope in its development phase has included the necessary work to evaluate available technologies in the market, lab evaluations for proof of concept and field trials at Claireville TS to further validate the technology to be deployed. This will allow Hydro One to be in an informed position to plan and implement the replacement efficiently while mitigating operational impacts to the transmission system.

Based on the assessments and results obtained from the earlier development phase, in 2019 MPLS was selected as the new replacement technology to satisfy Hydro One's technical requirements. An overall implementation and staging plan is currently being developed, which will include selection of the specific replacement solution from market participants, to be followed by multiyear systematic replacements. The test period estimated costs will be finalized through detailed estimates at the conclusion of the development phase.

Considering the scope of pre-implementation development, and volume and complexities of the changeover, it is anticipated that broad migration of communication services to the new platform will start in 2023, and is expected to proceed until 2027 to complete the migration for all nine rings of the communications network. The Investment was originally planned for execution starting in 2021; however, Investment timelines were adjusted in 2020 to better align with the approved capital envelope.

As the network undergoes this changeover, there will be a period of overlap when both the existing and the new platform will need to be operated and maintained.

D. OUTCOMES

The Investment will result in Hydro One's 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 will also enable the cost-effective deployment of applications that require modern IP connectivity and higher bandwidth, as well as eliminate the performance limitations and failures currently attributed to the older multiplexer equipment. The additional bandwidth available on the new replacement system will also allow Hydro One, where possible, to migrate services that are currently dependent on leased circuits due to high bandwidth requirements onto the new communication system, thereby reducing some Operations, Maintenance and Administration (OM&A) expenditures.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcomes Summary

Customer Focus	• Maintain telecommunication reliability for the 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.
Public Policy Responsiveness	• Hydro One is obligated to build and maintain a redundant communication/protection system to ensure that Hydro One meets the transmission system performance standard of NERC TPL-001.
Financial Performance	• Reduce OM&A costs associated with leased services by leveraging the new replacement communications system, where possible.

E. EXPENDITURE PLAN

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that will have been incurred prior to the 2023 test year. These include costs for the development phase that cover evaluation, testing and proof of concept, as well as implementation and staging plan development. The test period costs include the implementation costs which involve engineering, procurement and construction. Final costs of the project will be based on the overall technical solution that will be determined through detailed estimates at the conclusion of the development phase.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	11.6	20.3	30.6	30.5	28.7	8.6	-	130.3
Less Removals	0.2	0.8	1.2	1.2	1.1	0.3	-	4.9
Capital and Minor Fixed Assets	**11.4**	**19.5**	**29.4**	**29.2**	**27.6**	**8.3**	**-**	**125.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0.	-	0.0
Net Investment Cost	**11.4**	**19.5**	**29.4**	**29.2**	**27.6**	**8.3**	**-**	**125.4**

Major factors influencing the cost of the investment include:

- The large installed base of SONET equipment over a broad geographical area,
- Coordination and complexity of outages required to replace the SONET communications systems, and
- Hydro One will follow its established estimating process and project management practices to minimize controllable costs as explained in TSP Section 2.10.

F. 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 has been 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 and resource availability. Because SONET equipment is facing obsolescence, Hydro One's inventory of some spare parts is diminishing, further reducing the viability of maintaining the legacy system on a reactive basis.

ALTERNATIVE 2: PLANNED SONET REPLACEMENT

This is the preferred undertaking. This alternative will replace 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 will be coordinated. This will allow outages to be scheduled, thereby, reducing outage impacts, which will in turn alleviate the impact on communication system performance and Hydro One's customers. Complete replacement will also enhance the capability of the communication network resulting in the availability of communication infrastructure for future communication applications.

G. EXECUTION RISK AND MITIGATION

The main risk to the Investment is finding an overall solution based on MPLS technology that satisfies Hydro One's functional and economic requirements. Through the developmental phase of the Investment, a solution that fulfills the functional and economic requirements will be chosen from market participants and the Investment will be further developed with detailed estimates. This information will allow Hydro One to deploy the replacement solution in a planned and coordinated manner.

Due to the large installed base of the SONET system however, there will be deployment risks, which could result in delays. The primary source of potential delay 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.

T-SR-12	TELECOM PERFORMANCE IMPROVEMENTS
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	4.2	5.8	3.8	0.0	0.0	13.8

Summary:

This investment installs Optical Ground Wire (OPGW) on line B22D/B23D to remove obsolete digital microwave equipment on the Synchronous Optical Network (SONET) power system telecom Ring 6. The primary trigger of the investment is removal of obsolete equipment. The investment is expected to improve reliability of power system telecom serving teleprotection and supervisory control systems.

A. 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. While the Legacy SONET System Replacement project (T-SR-11) will replace multiplexer equipment that is beyond its ESL and is facing technological obsolescence with a new technology, this Project establishes more robust and reliable fibre-based communication links within SONET Ring 6.

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 Ring 6 of the Synchronous Optical Network (SONET) system.

The equipment that comprises these microwave links:

- Have reached the Expected Service Life (ESL),
- Are no longer being manufactured,
- Are technologically obsolete, and
- Have experienced a higher rate of failures of SONET system's digital microwave radios, which resulted in multiple power system telecom services being rendered unavailable until repairs were carried out.

The above facts illustrate the high risk of failure from this obsolete equipment. Loss of power system telecom services, which include communications channels for protection systems, 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 Ontario Grid Control Centre (OGCC) can no longer determine the status of the equipment). Removal of power system elements and power flow constraints negatively impact the reliability of the transmission grid. They create a less reliable grid configuration, due to the loss of redundancy and potentially expose customers to forced outages. In addition to the high reliability risk, these microwave links create a bandwidth bottleneck on the SONET network, limiting the full utilization of 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. The projected costs are estimated to be $10.6M over the 2023-2027 test period.

By the end of this project, there will be only one remaining SONET digital microwave link between Buchanon TS x Longwood SS. This link will be removed through network re-configurations once the OPGW on L24L (planned) and N21W/N22W (in-service) are fully functional.

In addition to above, this investment covers the 2023 portion of Telecom Performance Improvement – Ring 6/2 All Dielectric Self Supporting (ADSS) Cable Replacement. This project involves removal of approximately 100 km of ADSS cable (Between Detweiler TS, Orangeville TS and Essa TS) on D6V/D9V and E8V/E9V transmission lines and replacement thereof with OPGW fibre. The ADSS cable has had multiple failures in the last 10 years and the project to replace this cable was released in 2021 with a $3.2M expenditure in 2023 and project completion expected in that year.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

Hydro One's communication network, which is currently based on SONET technology, is primarily utilized by protection systems and SCADA monitoring systems. Additionally, it is used for communicating non-operational data, business data, voice and security information, and is used as backup for the provincial mobile radio system. The system includes multiplexers, optical amplifiers, digital microwaves and 48VDC backup power supply (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 a number of digital microwave links that were originally deployed where either fibre-based infrastructure was not economically feasible or third party leased fibre was not available. The associated digital microwave equipment is no longer being manufactured and is technologically obsolete. Hydro One takes into account asset age, installed base, strategic spares, rate of failures, compliance, functionality, availability of vendor support, manufacturer recommendations and historical asset retirement in order to plan asset replacements. 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 power system telecom services, which include communications channels for protection systems, can result in the removal of power system equipment from service and/or power flow constraint on the transmission system (as protection systems dependent on communications cannot protect the equipment and the OGCC can no longer determine the status of the equipment).

C. INVESTMENT DESCRIPTION

This Investment will remove microwave systems from SONET Ring 6 and replace them with OPGW on 230 kV line B22D/B23D. The Investment will occur over the 2023 to 2025 period with the last major microwave links being removed by Q4 2025.

Digital microwave systems have been part of SONET Rings 4, 6 and 8 which provide a microwave radio path between stations as opposed to fibre cable links. Most of the microwave equipment was installed on SONET Rings 6 and 8. Replacement of microwave links with OPGW on Ring 8 was completed in 2019. Investment for the replacement of the microwave link in Ring 4

(Cooksville TS) is expected to begin prior to 2023. This leaves ring 6 with the last remaining microwave links to be removed on the SONET system by 2025.

Table 1 below identifies the work that will be completed under projects in this investment

Table 1 - Telecom Performance Improvement Projects

Circuits	Project Description	Project In-Service Year
B22D/B23D	Replacement of the obsolete digital microwave radios on Ring 6 with the installation of OPGW on 230 kV line B22D/B23D	2025
D6V/D7V and E8V/E9V	Ring 6/2 ADSS Cable Replacement	2023

D. OUTCOMES

The Project will result in robust and reliable fibre-optic based communication infrastructure that will improve transmission system reliability.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Project in accordance with the OEB's Renewed Regulatory Framework:

Table 2 - 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.
Financial Performance	• Avoid maintenance costs associated with obsolete asset.

E. EXPENDITURE PLAN

Table 3 below summarizes historical and projected spending on the aggregate investment level during the test period.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	4.6	4.2	6.0	4.0	0.0	0.0	-	18.8
Less Removals	1.0	0.0	0.2	0.2	0.0	0.0	-	1.4
Capital and Minor Fixed Assets	**3.6**	**4.2**	**5.8**	**3.8**	**0.0**	**0.0**	**-**	**17.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**3.6**	**4.2**	**5.8**	**3.8**	**0.0**	**0.0**	**-**	**17.4**

The factors influencing the cost of the investment include:

- Planned costs are based on past deployment costs.
- Hydro One will follow its established estimating process and project management practices to minimize controllable costs.

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred alternative.

ALTERNATIVE 1: STATUS QUO: REACTIVE REPAIR OF DIGITAL MICROWAVE EQUIPMENT AND ADSS FIBRE

This alternative involves repairing microwave links as they fail. 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. In addition keeping the ADSS fibre links would lead to less reliable overall network infrastructure. This approach would lead to an unacceptable level of risk to system reliability.

Microwave equipment is manufacturer-discontinued, obsolete, and is no longer receiving vendor support. This results in much longer repair times during which the equipment is out of service and there is loss of redundancy in that SONET ring. This is undesirable level of equipment performance as it degraded the reliability of the protection systems in the area.

ALTERNATIVE 2: PLANNED REPLACEMENT OF MICROWAVE LINKS AND ADSS FIBRE

Planned Replacement of Microwave Links and ADSS fibre is a preferred alternative. This alternative will replace SONET microwave links with OPGW, which will provide robust and reliable communication links for Ring 6. It also allows for coordinated replacement, which will schedule outages to reduce impacts on telecommunication system performance and Hydro One's customers. This alternative also removes ADSS fibre cables which have had failures in the past to be replaced with more reliable OPGW links.

G. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the Project are: outage constraints, resource constraints, construction execution challenges, customer coordination, real estate requirements, procurement challenges, or regulatory 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 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.

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T-SR-13	**TRANSMISSION LINE COMPLETE REFURBISHMENT**
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	60.1	125.9	190.8	235.9	220.5	833.2

Summary:

Hydro One is proposing a series of investments that target complete refurbishment of transmission line sections that have been confirmed, through condition assessment to be in poor condition. The primary trigger of each investment is the verified functional deterioration of overhead conductors that requires replacement. The investment is required to mitigate the safety and reliability risks presented by operating transmission lines sections that have components deteriorated into poor condition.

A. OVERVIEW

This investment summary document consists of sixteen investments. Each aims to comprehensively sustain overhead transmission line sections through the refurbishment or replacement of transmission line components (e.g. overhead conductors, structures, foundations, insulators, and shieldwires), verified to be in poor condition. The primary focus of each investment is to address poor condition overhead conductors that typically exhibit deteriorated ductility, tensile strength or both.

Hydro One's overhead conductors are aging and Hydro One is not keeping pace with asset condition demands. Currently, 3,874 circuit-kms or 14% of Hydro One's conductor fleet has been empirically tested and confirmed to be in poor condition. That is an increase from 2,643 circuit-kms of poor condition conductors at the end of 2016 and 3,680 circuit-kms of poor condition conductors at the end of 2018. Hydro One plans to replace 1,879 circuit-kms (of which 1,571 circuit-kms will be in-serviced during the 2023-2027 period) or 49% of the known poor condition conductors in the fleet. This set of 1,879 km is split between sixteen investments that have been put together to address the subset of poor condition conductors in the greatest of need, among other things. Some of the highlights are as follow:

- All sixteen investments address circuits with poor condition lines components that are located in publicly accessible areas;
- Twelve of the sixteen investments aim to sustain circuits that form part of the North American Electric Reliability Corporation's (NERC) Bulk Electric System (BES) that connects major generation sources and delivers that power to load centers throughout Ontario;
- Two investments aim to address poor performing radial lines located in Northern Ontario that serve critical customers such Ontario Power Generation, large industrial customers and First Nations communities

Given the critical role of electricity in the functioning of Ontario's homes, businesses and institutions, Hydro One's priority is to maintain overhead conductors in-service. This investment focuses on replacing conductors based on asset 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, a line refurbishment investment is planned and scheduled. Line refurbishment investments are prioritized taking into account the condition as well as the consequence of failure to the system and connected customers. Line refurbishment investments incorporate the refurbishment of all deteriorated components within the targeted line section, including structures, shieldwire, and insulators. Given that the conductor has one of the longest expected service lives (ESL) among transmission line assets, when it requires replacement, other lines components will likely also have deteriorated to poor condition and require replacement or refurbishment as well.

In light of the foregoing, where multiple line components have been confirmed to be in poor condition, Hydro One utilizes an integrated approach to refurbish and replace multiple line components. Bundling conductor replacement with the replacement of other components is cost effective and schedule as well as resource efficient for sustaining an overhead power line. By employing the integrated approach, Hydro One can complete the necessary asset replacements at once as opposed to requiring repeated investments which would result in re-engineering, repeated construction mobilization, and increased planned outages coordination at the same work location within a small time period.

B. NEED AND OUTCOME

B.1 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 (cct-km) of transmission conductors spanning across the diverse geography of Ontario. The overhead conductor is a major transmission line component and 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 in order to avoid and/or mitigate significant safety and operational risks. Overhead conductors do not deteriorate consistently or in a predictable manner. The actual service life of each conductor segment has been observed to vary between 50 and 120 years, and the asset's deterioration rate depends on numerous uncontrollable variables, such as manufacturing quality, location, installation orientation, local atmospheric contaminant levels, weather cycles and stringing tension. The climate of Ontario is diverse with a warm and humid climate in the southern part of the province and a harsh, subarctic climate in the northern parts of the province. Hydro One's fleet of overhead conductors is located throughout the province and is subject to varying degrees of exposure to environmental stresses from weather cycles. This affects how fast the asset deteriorates. 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 harsh 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 a varying degree, 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, the types of which a conductor would experience during storm conditions 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: Dissected ACSR Conductor from Circuit B5C Revealing Deteriorated Core Strands with Pitting Corrosion

Hydro One's conductor fleet has 464 circuit-km of copper conductors, which is the oldest type of conductor in Hydro One's transmission network. 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.

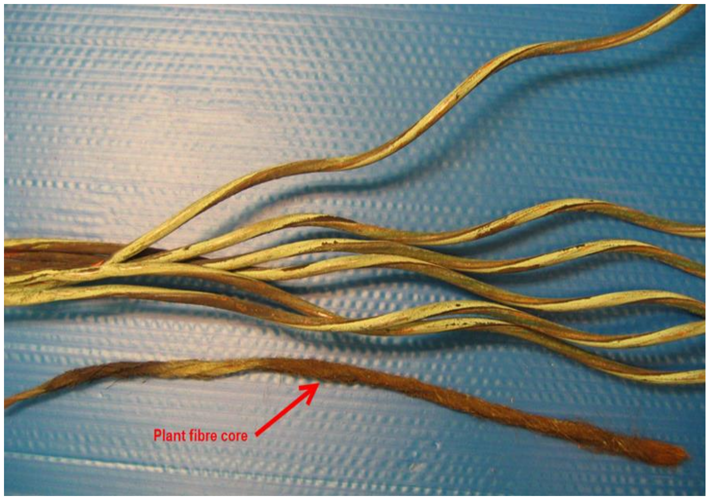

Figure 2: Dissected copper conductor

Hydro One determines the condition of its transmission overhead conductors through empirical testing. As outlined in the TSP Section 2.2, 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 and short sample testing provides an initial 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 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 is expected 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 the subcomponents concurrently. Deterioration on a subcomponent only, such as connectors, would be considered a subcomponent issue and not attributed to the deterioration of the overall conductor system.

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, there is a high degree of reliability. A failure of one of the two circuits supplying the delivery point does not impact service to customers because they continue to receive uninterrupted supply from the multiple circuit connected bus. Such failures are nonetheless a major concern for Hydro One, the IESO and the LDCs that are being supplied from that delivery point. This concern arises because replacing a failed asset takes a considerable amount of time. At any point prior to replacement of the failed circuit, an outage impacting the second circuit would result in a lengthy delivery point interruption.

In light of the foregoing, reliability statistic is a lagging indicator. It measures customer interruptions after these interruptions have already happened. By the time reliability statistics start to deteriorate for delivery points served by dual supplies, numerous customers will have been affected and service to the public compromised.

Transmission lines located in publicly accessible areas pose a serious 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 pose 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

C. INVESTMENT DESCRIPTION

Based on the above need, Hydro One currently has 3,874 circuit-kms (or 14%) of its conductor fleet in poor condition, with another 3,329 circuit-kms (or 12%) exhibiting some deterioration, but not to an extent necessitating replacement at this time. Hydro One plans to replace 1,879 circuit-kms (of which 1,571 circuit-kms will be in-serviced during the 2023-2027 period) or 49% of the known poor condition conductors in the fleet over the 2023-2027 planning period. Hydro One is not planning to replace any of the fair condition conductors. This set of 1,879 circuit-kms is split between sixteen investments that have been put together to address the subset of poor condition conductors in the greatest of need and which are logistically available for sustainment at this time. Some of the highlights are as follow:

- All sixteen investments address circuits that are located in publicly accessible areas;
- Twelve investments aim to sustain circuits that form part of the NERC's BES that connects major generation sources and delivers that power to load centers throughout Ontario;
- Two investments aim to address poor performing radial lines located in Northern Ontario that serve critical customers such Ontario Power Generation, large industrial customers and First Nations communities;

These investments will help mitigate the severe safety consequences that could arise from failed/falling conductor and avoid the unacceptable exposure of the system/customers to elevated operating risks arising from transmission circuit outages.

D. OUTCOMES

The comprehensive refurbishment 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 land owners; maintain long-term reliability of connected stations and transmission customers; and reduce constraints on generation resources.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 1 - Outcomes Summary

Customer Focus	• The refurbishment 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.
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 refurbishment will alleviate this threat. • Reduce line losses where applicable.
Public Policy Responsiveness	• Refurbishing 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 public or employees, damaging property or damaging local environment (fire caused by dropped energized conductor).
Financial Performance	• Realize cost savings by bundling the refurbishment of all components along the line section undergoing poor condition conductor replacement.

E. EXPENDITURE PLAN

Table 2 below summarizes historical and projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	32.2	65.3	136.8	207.4	256.5	239.7	106.8	1,044.6
Less Removals	2.1	5.2	10.9	16.6	20.5	19.2	8.5	83.1
Capital and Minor Fixed Assets	**30.1**	**60.1**	**125.9**	**190.8**	**235.9**	**220.5**	**98.2**	**961.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**30.1**	**60.1**	**125.9**	**190.8**	**235.9**	**220.5**	**98.2**	**961.5**

The factors influencing the cost of the investment include:

- In the latter years of the filing period, higher voltage and BES circuits are replaced, this results in a higher absolute and unit cost value for line refurbishment expenditures.
- In each investment, the number of 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 refurbishment in-situ. This can add additional real estate and vegetation clearing costs to the investment.
- Community impacted by the investment:
    - Line refurbishments are in the public domain and as such can impact many interfacing stakeholder including property owners, other utilities, and indigenous communities. As such, interfacing costs can vary from investment to investment.

F. 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 the public domain, where broken overhead components can disconnect from the overhead line and fall, endangering all in proximity of its fall. 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:

- Failures cannot be predicted and so will always need unplanned mitigation. Unplanned mitigation of failures can be prolonged and can therefore result in extended equipment and customer outages which will subsequently negatively impact 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 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 approach is likely to increase operating and maintenance costs, decrease equipment performance and may impact the safety of personnel on site.

ALTERNATIVE 2: PROGRAMMATIC SUSTAINMENT OF COMPONENTS (UNBUNDLED)

Planned Replacement of transmission line components individually through component programs (unbundled) involves the piecemeal replacement of lines components in poor condition. This alternative is viable only when single components along a line section are deteriorated. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components along a line section are in a deteriorated condition or operational concerns exist with respect to these components. Since a component based planned replacement strategy would only replace assets as they deteriorate to poor condition, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a comprehensive line refurbishment, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to upgrade, reduce line losses, or to eliminate any existing operational concerns along a line section.

ALTERNATIVE 3: COMPREHENSIVE LINE SECTION REFURBISHMENT (BUNDLED)

An integrated approach of refurbishing all deteriorated transmission line components along a line section is a proven efficient and effective means for sustaining transmission lines when multiple components require sustainment. This integrated approach sustains all components along a line section that have been verified to be in poor condition, including overhead conductors, structures, foundations, insulators, and shieldwires, to bring the line section to like-new condition. By employing the integrated approach, Hydro One can complete the necessary asset replacements along a line section at once as opposed to requiring repeated investments which would result in re-engineering, repeated construction mobilization, and increased planned outages coordination at the same work location within a small time period. This approach minimizes disruption to local land owners and outages on particular circuit(s). Furthermore, comprehensively refurbishing a complete line section presents an opportunity to review the circuit for operational improvements or upgrading, for either the benefit of the overall system or particular customers. This approach allows Hydro One to consult with customers to ensure the planned refurbishment of a transmission lines optimally meets the present and future needs of connected customers and the system operator. These comprehensive line refurbishments also allow for an opportunity to reduce line losses where appropriate.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, 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 refurbishment 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 is not 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 effort to coordinate with customers and community stakeholder 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 refurbishment.
- Procurement challenges:
  - Major equipment procurement lead times.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

ISD Ref.	Circuit	Scope, Need and Outcome	Total Units Replaced
			Circuit-kms
T-SR-13.1	T22C and T28C 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 231 km of 230 kV 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. Bundled within this investment will be the refurbishment of 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./Veridian Connections Inc., and Hydro One Distribution connected communities.	231
T-SR-13.2	T25B 230 KV Part of NERC's Bulk Electric System (BES) & Blackstart cranking path	• This investment refurbishes a total of 120 km of 230 kV circuit T25B between Pancake JCT and Clarington TS. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. Bundled within this investment will be the refurbishment of 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 publically 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.	120

T-SR-13.3	E1C 115 KV	• This investment refurbishes a total of 162 km of 115 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including a generator, a lumber company and local Hydro One Distribution connected communities. • This circuit services the indigenous communities of Mishkeegogamang, Slate Falls First Nation and Cat Lake First Nations.	162
T-SR-13.4	D2H, D3H, D6T and D4 115 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 183 km of 115 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including generators and local Hydro One Distribution connected communities. • Circuit D2H and D3H cross several major roadways including highway 634.	183
T-SR-13.5	T33E 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 252 km of 230 kV 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. Bundled within this investment will be the refurbishment of 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 publically 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

T-SR-13.6	Q2AH and A8G 115 KV	• This investment refurbishes a total of 22 km of 115 kV circuits Q2AH and A8G between Rosedene JCT and St. Anns JCT. • The investment is needed to address the obsolete copper conductors along this line. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including Niagara Peninsula Energy Inc., Alectra Inc., and local Hydro One Distribution connected communities.	22
T-SR-13.7	E8V and E9V 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 112 km of 230 kV 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. Bundled within this investment will be the refurbishment of verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s. • Circuits E8V and E9V are located south of the city of Barrie in Central Ontario. The circuit is publically accessible and services local Hydro One Distribution connected communities. • Circuits E8V and E9V crosses several major rail and roadways including County Road 56.	112
T-SR-13.8	L22H 230 KV Part of NERC's Bulk Electric System (BES) & Blackstart cranking path	• This investment refurbishes a total of 65 km of 230 kV circuit L22H between Easton JCT X Hinchinbrook North JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. Bundled within this investment will be the refurbishment of verified deteriorated shieldwire, insulators and lattice steel structures. • This line section was originally constructed in the 1940s. • Circuit L22H is located north of the city of Kingston in Eastern Ontario. The circuit is publically accessible and services local Hydro One Distribution connected communities.	65

T-SR-13.9	M6E and M7E 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 50 km of 230 kV circuits M6E and M7E between Cooper's Falls JCT and Orillia TS. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. Bundled within this investment will be the refurbishment of verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s. • Circuits M6E and M7E are located near the city of Orillia in Central Ontario. The circuit is publically accessible and services several customers including Alectra Inc. and local Hydro One Distribution connected communities. • These circuits service the Chippewas of Rama First Nation indigenous community.	50
T-SR-13.10	A4H and A5H 115 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 47 km of 115 kV circuits A4H and A5H between A.P. Tunis JCT and Fournier JCT. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including industrial customers, generators and local Hydro One Distribution connected communities. • These circuits service the Taykwa Tagmou Nation indigenous community.	47
T-SR-13.11	B5QK 115 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 60 km of 115 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including Kingston Hydro Corp. and local Hydro One Distribution connected communities.	60

T-SR-13.12	A4L 115 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 78 km of 115 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including local Hydro One Distribution connected communities. • This circuit services the Biinjitiwaabik Zaaging Anishinaabek (BZA) aka Rocky Bay First Nation indigenous community. • Circuit A4L crosses several major rail and roadways including highway 11.	78
T-SR-13.13	D1M, D2M, D3M and D4M 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 248 km of 230 kV circuits D1M, D2M, D3M and D4M between Otter Creek JCT and Minden TS. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated ductility. Bundled within this investment will be the refurbishment of verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1950s. • Circuits D1M, D2M, D3M and D4M are located near Haliburton County in Central Ontario and traverses Algonquin Provincial Park. The circuit is publically accessible and services local Hydro One Distribution connected communities.	248
T-SR-13.14	N5K 115 KV	• This investment refurbishes a total of 65 km of 115 kV circuit N5K between Sarnia Scott TS and Kent TS. • The investment is needed to address the verified poor condition ACSR conductors along this line, which exhibit deteriorated tensile strength. Bundled within this investment will be the refurbishment of verified deteriorated shieldwire, insulators and lattice steel structures. • These line sections were originally constructed in the 1940s. • Circuit N5K is located in the city of Sarnia in Southwest Ontario. The circuit is publically accessible and services several customers including Entegrus Powerlines Inc. and local Hydro One Distribution connected communities. • This circuit services the Walpole Island indigenous community. • Circuit N5K crosses near McNaughton Ave Public School in Chatham and several major rail and roadways including Grand Avenue.	65

T-SR-13.15	S2N 115 KV	• This investment refurbishes a total of 54 km of 115 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including Entegrus Powerlines Inc., gas and petro-chemical companies, and local Hydro One Distribution connected communities. • This circuit services the Chippewas of Kettle and Stony Point First Nation indigenous communities. • Circuit S2N crosses several major rail and roadways including Mandaumin Road, Kimball Road, Oil Heritage Road and Plank Road.	54
T-SR-13.16	C27P 230 KV Part of NERC's Bulk Electric System (BES)	• This investment refurbishes a total of 130 km of 230 kV 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. Bundled within this investment will be the refurbishment of 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 publically accessible and services several customers including Ontario Power Generation Inc. and local Hydro One Distribution connected communities.	130
	Total		**1,879**

Witness: JABLONSKY Donna

APPENDIX B – DETAILED INVESTMENT COSTS

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 2.10. 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 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.

ISD Ref.	Station Name	EB-2019-0082	Type	Net Capital Investment ($ Millions)							In Service Year
				2023	2024	2025	2026	2027	23-27 Total	Proj. Total	
T-SR-13.1	T22C and T28C 230 KV	SR-20	P	0.0	0.9	18.0	26.7	34.0	79.6	79.6	2027
T-SR-13.2	T25B 230 KV	SR-20	P	0.0	0.0	2.1	16.6	36.3	55.0	82.7	2028
T-SR-13.3	E1C 115 KV	-	P	17.7	13.3	0.0	0.0	0.0	31.0	51.8	2024
T-SR-13.4	D2H, D3H, D6T and D4 115 KV	SR-19	P	26.7	27.1	28.7	0.0	0.0	82.4	89.9	2025
T-SR-13.5	T33E 230 KV	-	P	0.2	8.3	35.6	55.4	49.3	148.8	170.6	2027
T-SR-13.6	Q2AH and A8G 115 KV	SR-19	P	0.5	5.1	3.7	0.0	0.0	9.2	9.2	2025
T-SR-13.7	E8V and E9V 230 KV	SR-20	P	2.1	14.8	23.5	17.9	0.0	58.3	58.3	2026

T-SR-13.8	L22H 230 KV	SR-20	P	1.7	19.6	25.4	11.6	0.0	58.2	58.2	2026
T-SR-13.9	M6E and M7E 230 KV	SR-20	P	0.7	7.2	12.2	5.2	0.0	25.2	25.5	2026
T-SR-13.10	A4H and A5H 115 KV	SR-20	P	0.0	0.0	0.8	15.5	3.2	19.5	19.7	2027
T-SR-13.11	B5QK 115 KV	SR-20	P	0.0	0.2	0.9	10.1	18.4	29.6	29.6	2027
T-SR-13.12	A4L 115 KV	SR-20	P	1.0	11.8	10.6	0.0	0.0	23.4	23.8	2025
T-SR-13.13	D1M, D2M, D3M and D4M 230 KV	SR-20	P	0.0	4.0	10.2	36.3	41.6	92.1	121.3	2028
T-SR-13.14	N5K 115 KV	SR-19	P	0.9	3.2	10.3	10.8	7.8	33.1	33.1	2027
T-SR-13.15	S2N 115 KV	-	P	8.8	10.4	8.1	0.0	0.0	27.3	28.0	2025
T-SR-13.16	C27P 230 KV	SR-20	P	0.0	0.0	0.6	29.9	29.9	60.4	80.3	2028
	Total			60.1	125.9	190.8	235.9	220.5	833.2	961.5	

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T-SR-14	MOBILE RADIO SYSTEM REPLACEMENT
Primary Trigger:	Obsolescence/Compliance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	5.2	6.7	5.6	2.4	0.0	19.9

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 mobile radio system. Availability of reliable radio communications for field crews – as provided by the provincial mobile radio system - is an operational requirement at Hydro One Networks, serving both transmission and distribution crews. The primary trigger of the investment is to replace obsolete infrastructure throughout the province using an up-to-date and modern mobile radio network. The investment is expected to provide a reliable means of two-way voice communication throughout the province, which meets the needs of control centre dispatch as well as operational and safety requirements for the field crews.

A. OVERVIEW

This investment involves procuring a solution to replace the existing provincial mobile radio system. The existing radio technology used for Hydro One's private mobile radio system is obsolete and requires replacement as the stockpile of strategic spares will be exhausted over the next few years. 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 and the condition of the deployed equipment. The investment will implement a new technology solution to continue providing dispatch capability between control centre and field staff as well as communications among field crews when maintaining and restoring transmission system assets.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

Hydro One owns and operates a private radio system that is used for two-way voice communication between control centers and field crews, and among filed crews. This system is used by forestry and lines crew during restoration efforts, emergency operations and during day-to-day construction and maintenance work. The mobile radio 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 private mobile radio system is obsolete having reached end of vendor support (EVS). Equipment for the system is no longer manufactured, and Hydro One's strategic spares will be exhausted over the next few years. When the strategic spares have been exhausted, Hydro One will be unable to 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/or 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 deployed equipment necessitate replacing the current provincial radio system. In light of the foregoing, a new technology solution is needed to continue providing communications between control centres and field staff when maintaining and restoring transmission system assets.

C. INVESTMENT DESCRIPTION

This investment will procure a solution to replace the existing provincial mobile radio system. The planned mobile radio replacement project will:

- Examine available technologies such as satellite based-communication, radio over IP, trunked radio system, as potential hybrid and integrated solutions to the existing hand-held and in-vehicles units used by field staff;
- Study the technical and economic feasibility of each of the viable technologies, select technology for small scale deployment as a proof of concept, with due consideration for future operating costs; and
- Assess the infrastructure required to ensure that the necessary coverage is provided prior to new system's deployment.

The investment is paced to allow the new system to be fully tested prior to deployment. Multi-year deployment will also smooth the transition to the new system while utilizing the existing system to its full extent. It is expected that the new system will be fully implemented by Q4 2026.

Table 1 - Provincial Mobile Radio System

System	Project Description	Project In-Service Year
All TX and DX Sectors	Replace the Provincial Mobile Radio analog System with a digital Land Mobile Radio (LMR) system in a licensed VHF frequency band or a hybrid LMR and Satellite system to serve OGCC and DOMC dispatch needs as well as field crew operational voice requirements.	2026

D. OUTCOMES

By replacing the existing provincial mobile radio system, Hydro One will be able to continue providing voice communication between control centers and field crews, 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.

D.1 OEB RRF OUTCOMES

The following table presents the benefits anticipated as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 2 - Outcomes Summary

Customer Focus	• Maintain the 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.
Financial Performance	• Work efficiency will result in lower Operations, Maintenance, and Administration (OM&A) costs associated with power restoration and emergency operations.

E. EXPENDITURE PLAN

The previous years' costs (2022) are for the development phase, estimation and preparation of a Request for Proposal for the project. As part of this phase of the project a new technology (Satellite-based) will be evaluated, tested and system deployment costs will be estimated.

Planned costs in 2023 and beyond are related to province-wide deployment of the new solution. The project is planned for completion by Q4 2026, and lower costs are expected that year as the project wraps up.

Table 3 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have been incurred prior to the 2023 test year. No investment costs are forecast beyond 2028.

Table 3 – Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	3.4	5.4	7.0	5.8	2.5	0.0	-	24.1
Less Removals	0.1	0.2	0.3	0.2	0.1	0.0	-	0.9
Capital and Minor Fixed Assets	**3.3**	**5.2**	**6.7**	**5.6**	**2.4**	**0.0**	**-**	**23.2**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**3.3**	**5.2**	**6.7**	**5.6**	**2.4**	**0.0**	**-**	**23.2**

The factors influencing the cost of the investment include:

- Final costs will be based on the technology solution selected to replace the existing system.
- Hydro One will follow its established estimating process and project management practices to minimize controllable costs.

F. 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 provincial mobile radio system in its current state. Hydro One will be unable to restore failed radio equipment in fleet trucks and base station due to the lack of spare parts and vendor support. This situation would render voice communication unavailable for field staff and control centers. As a result, Hydro One would 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.

This is the preferred alternative. Hydro One can replace the existing legacy provincial mobile radio system with a new system. This alternative involves procuring a fully integrated solution that meets the communication needs of the control centre dispatch and field crews using commercially available and supported technology. 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.

G. EXECUTION RISK AND MITIGATION

The risk to implementing this investment is finding a technologically and economically feasible solution. For example, a new system at higher frequency may require proportionally larger infrastructure, resulting in higher costs than estimated. Hydro One will execute a development phase of the project to explore the available technologies and select a solution that meets technical and business requirements before pursuing implementation.

T-SR-15	TRANSMISSION LINE EMERGENCY RESTORATION
Primary Trigger:	Asset Failure or High Risk of Failure
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	10.2	10.4	10.6	10.8	11.0	53.0

Summary:

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. The primary trigger for the investment is asset failure or a 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 TSC.

A. OVERVIEW

The Transmission Lines Emergency Replacement program is reactive in nature, mainly to provide an immediate response to an emergency situation or to prevent or minimize the effects of an emergency situation. This investment funds the emergency replacements 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 cause an impact on the transmission system that varies from being minor to significant. It also poses safety risk as well as power delivery risk which might affect 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 Transmission System Code (TSC). This investment program ensures that Hydro One continues to comply with its commitment and legal obligations to mitigate safety, system reliability and environmental risks that an unforeseen failure might cause.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

The TSC states a transmitter is required to take immediate action during an emergency or in order to prevent or minimize the effects of 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 Hydro One’s transmission facilities. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the TSC.

Hydro One’s transmission system extends to 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 being 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 danger of failure due to weather events, component deterioration, design deficiencies, vandalism, or accidents caused by public activity. Almost all of the transmission lines system is located within public domain. In light of the foregoing, the primary focus of this investment is to ensure public and employee safety.

This investment is also focused on maintaining reliability and minimize power delivery impact. 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 in order to ensure public and employee safety and 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, impacting power delivery and resulting in customer interruptions.

C. INVESTMENT DESCRIPTION

An emergency situation 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 the emergency replacements 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 components failure include: weather conditions (i.e. lightning), severe weather events (i.e. tornado), deterioration, design deficiencies, vandalism, accidents caused by public activity. In addition to structures and/or components that have failed as shown in the figures below, Hydro One must also respond to structures and components at risk of imminent failure that are identified through condition 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: 2016 L20D (Kipling GS x Harmon Jct) Steel Structure Failure Due to Windstorm

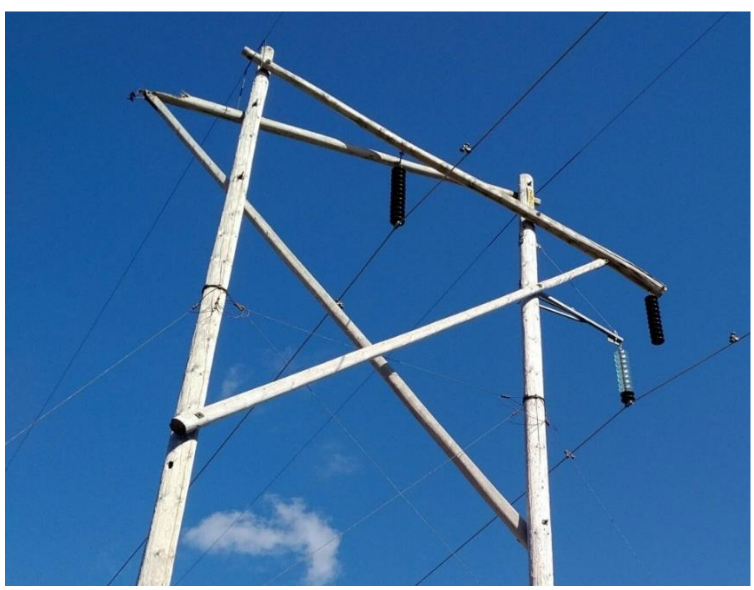

Figure 2: 2017 W71D (Lower Notch Jct x Widdifield SS) Wood Pole Failure

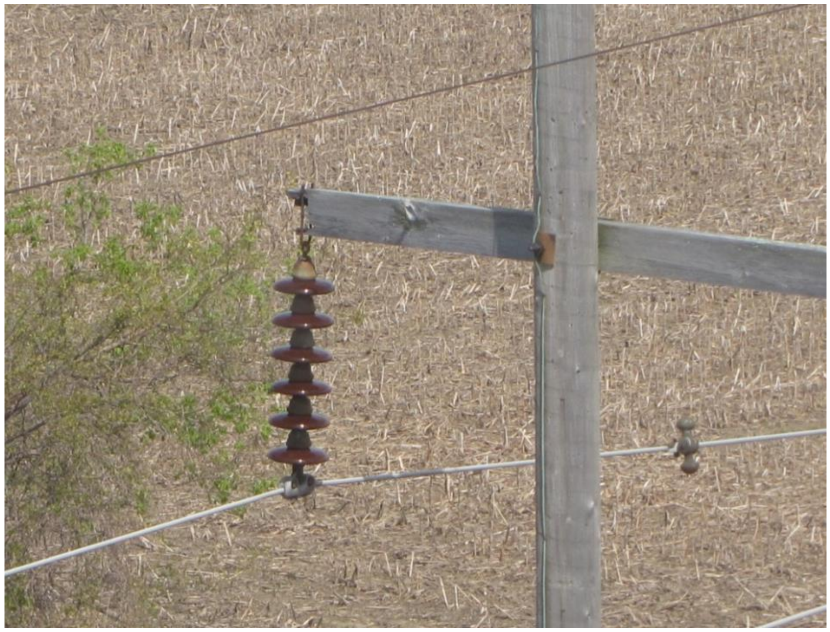

Figure 3: 2017 K2Z (Gosfield Wind CGS x Kingsville TS) Wood Arm at Imminent Danger of Failure

Figure 4: 2018 K2Z (Haycroft DS x Belle River Jct) Steel Structure Failure

D. 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.

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 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. • Comply with TSC obligations by providing safe and reliable electricity to Ontario electric consumers.

E. EXPENDITURE PLAN

Table 2 below summarizes the 2023-2027 period spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	2023	2024	2025	2026	2027	Total
Gross Investment Cost	11.1	11.3	11.5	11.8	12.0	57.7
Less Removals	0.9	0.9	0.9	0.9	1.0	4.6
Capital and Minor Fixed Assets	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**53.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**53.0**

The average investment cost for this investment over the five-year period is in line with the average five-year historical spending. The factors influencing the cost of the investment include:

- The scope of the replacement work required; and
- The type and quantity of assets requiring replacement.

F. ALTERNATIVES

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 and violate the TSC.

G. EXECUTION RISK AND MITIGATION

The work that is part of this investment program is 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.

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T-SR-16	HV UG CABLE – REPLACE/REFURBISH PUMPING PLANTS
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	-	-	0.1	0.2	5.5	5.8

Summary:

This investment involves the replacement and refurbishment of pumping plants used to support the operation of the high-pressure liquid-filled (HPLF) underground cable system. These pumping plants have reached end of life. The primary trigger for the investment is condition however obsolescence is also considered. This investment is expected to replace or refurbish approximately nine pumping plants to maintain the reliability of the HPLF cable system.

A. OVERVIEW

Approximately 63% of Hydro One's underground transmission system consist of 115 kV and 230 kV HPLF cables that operate dependably, provided that the dielectric fluid is continually pressurized. Pumping plants are employed to maintain a constant stable pressure and are vital for reliable HPLF cable operation. Through condition assessment and functional testing, these assets have been verified as needing to be replaced. Most pumping plants were installed in the 1970s and 1980s with control systems upgraded/replaced in the 1990s. Due to their age, many components are obsolete with few spare parts suppliers.

When non-functioning pumping plants result in a significant loss of pressure, the cables served by the failed plants will be immediately taken out-of-service, impacting customers through loss of supply or redundancy. Loss of pressure may also cause permanent damage to the connected underground cables. Therefore, replacement or refurbishment of the pumping plants before failure is required to minimize impacts on customers and potential damage to equipment.

This investment will replace or refurbish approximately nine pumping plants. Replacement will be done when major components such as piping, values, civil infrastructure (buildings) and/or tanks are in poor condition. Refurbishments will involve individual component replacements and focus on control, monitoring, alarm, communication, cathodic protection, backup and HVAC systems. The investment cost is estimated to be $5.8M over the 2023-2027 Test period and is expected to be in-serviced in 2028.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

In an oil-filled cable system, pressure fluctuates based on load and the environment. Pumping plants, also known as pressurization plants, are employed to maintain a constant stable pressure and are vital for reliable HPLF cable operation. Pumping plants consist of the following principal components: reservoir tanks; values; manifolds; mechanical and electrical motors and pumps;

control, monitoring, alarm, communication, cathodic protection, backup operating/pressurization and HVAC systems; and associated civil infrastructure.

Non-functioning pumping plants resulting in a significant loss of pressure will cause the cables to be immediately taken out-of-service, impacting customers through loss of supply or redundancy. This may also cause permanent damage to the connected underground cables potentially resulting in the need for cable replacement since this type of damage cannot be repaired. Cable replacement is costly and time consuming and would further impact service to customers.

Non-functioning control, monitoring, alarm and/or communication systems will result in an inability to monitor/log pressures, temperatures, alarm details, oil/gas levels and pump operations; and/or maintain oil pressure. This information is essential to troubleshooting pumping plant breakdowns and is needed to reliably operate the HPLF cable system. Furthermore, control system failures would require oil pressures and levels to be monitored and controlled manually on-site 24/7. Oil-filled cables must remain under positive pressure to operate and prevent premature degradation.

As discussed in detail in TSP Section 2.2, the majority of Hydro One’s underground cables are installed in densely populated urban areas, such as the Greater Toronto Area (GTA), Ottawa and Hamilton, and through the Local Distribution Company (LDC) serve a significant portion of load in those regions. Therefore, failures resulting in loss of supply or redundancy will affect large numbers of downstream customers (i.e. LDC customers). Pumping plants are integral to reliably operating HPLF cables and supplying connected customers.

C. INVESTMENT DESCRIPTION

This investment will replace or refurbish approximately nine pumping plants. Replacement will be done when major components such as piping, values, civil infrastructure (building) and/or tanks are in poor condition. Refurbishments will involve individual component replacements and focus on control, monitoring, alarm, communication, cathodic protection, backup and HVAC systems.

D. OUTCOMES

D.1 OEB RRF OUTCOMES

As a result of the investment, through the replacement and refurbishment of the pumping plants, Hydro One will maintain reliability and minimize future costs associated with the unplanned repair of pumping plants and cable replacement. This will eliminate the risks to reliability associated with operating poor condition assets, eliminate current obsolescence risks associated with operating dated components and allow for the continued reliable operation of the connected HPLF cables.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Maintain system and customer reliability of the HPLF cable system by replacing degraded end of life assets
Operational Effectiveness	• Maintain operational effectiveness of connected HPLF cables by replacing poor condition and obsolete equipment

E. EXPENDITURE PLAN

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in "Forecast 2028+" are investment costs forecast beyond 2028.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	-	-	-	0.1	0.2	5.5	5.6	11.4
Less Removals	-	-	-	-	-	-	-	-
Capital and Minor Fixed Assets	**-**	**-**	**-**	**0.1**	**0.2**	**5.5**	**5.6**	**11.4**
Less Capital Contributions	-	-	-	-	-	-	-	-
Net Investment Cost	**-**	**-**	**-**	**0.1**	**0.2**	**5.5**	**5.6**	**11.4**

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred investment.

ALTERNATIVE 1: STATUS QUO

Reactive replacement of pumping plants or select components is the "status quo" alternative, which means Hydro One will continue to operate and maintain the existing pumping plants and replace them upon failure. This alternative was considered and has been rejected as failure of these assets may result in permanent cable damage requiring cable replacement, prolonged circuit outages, potential customer interruptions and loss of redundant supply negatively affecting operational flexibility.

ALTERNATIVE 2:

Planned replacement is the preferred alternative. It involves planned replacement of pumping plants or select components with modern systems. The replacement of deteriorated and obsolete components will address reliability and obsolescence concerns associated. Not proceeding with this investment will result in a higher likelihood of unrepairable cable failures.

G. EXECUTION RISK AND MITIGATION

No major execution risks are expected. However, there is potential for normal execution risks that may affect the timely completion of the investment, such as outage availability. This risk will be mitigated by scheduling and coordinating with customers and other planned outages. In addition, care will need to be taken to ensure that the connected HPLF cables remain under pressure during construction; and for select component replacements, that these components are reliably integrated into the existing system. These risks will be mitigated through detailed planning and preparation with the execution team and contractors.

T-SR-17	OPGW INFRASTRUCTURE PROJECTS
Primary Trigger:	Performance
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	28.5	27.8	30.4	20.1	10.5	**117.3**

Summary:

This investment involves a number of smaller multi-year projects aimed at installing reliable, Optical Ground Wire (OPGW) on select 230 kV and 115 kV transmission line across the province. These installations will eliminate gaps, provide additional geographic diversity and increase coverage of the existing fibre network serving power system telecom applications. The primary trigger of the investment is to improve the performance of the existing power system telecom network by replacing failing third-party fibre infrastructure and leased Telco metallic facilities with more reliable, Hydro One owned OPGW fibre infrastructure.

A. OVERVIEW

Hydro One utilizes fibre optic cable infrastructure including Hydro One owned and operated Optical Ground Wire (OPGW) and All Dielectric Self Supporting (ADSS) aerial fibre optic cables. In addition, Hydro 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. Hydro One also will replace some leased metallic copper-based circuits from telecommunication service providers (Telco) that provide communication-aided protection schemes at transmission stations.

In order to maintain the reliability of the transmission system, Hydro One’s current asset management strategy is to (i) identify opportunities and gradually replace the use of less reliable third-party fibre with Hydro One’s OPGW fibre to the extent possible; and (ii) increase the existing OPGW footprint in order to extend fibre coverage to Hydro One facilities that currently experience less reliable leased metallic services from Telco. To this end, Hydro One has proactively leveraged the installation of OPGW as part of transmission line shieldwire replacements and line refurbishment investments where economically feasible. Because these projects are driven by replacements of poor condition transmission line shieldwire, the associated OPGW installation may not provide complete end-to-end fibre connectivity. The projects funded through this Investment have been designed to complement the OPGW installations by addressing gaps in the OPGW infrastructure, thereby creating end-to-end fibre-based telecom paths.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

This investment is needed to address the reliability risks posed by failing, leased third-party fibre as well as leased circuits provided by Telco.

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, 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 50% or 1700 km) consists of leased third party fibre. The market for dark fibre has shifted from what it was 20 years ago and the availability of new fibre and renewal of existing contracts pose significant operational risk to the Power System Telecom Services (PSTS) network.

It is important to note that third-party fibre routes perform worse that 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. The worst performing SONET ring in Hydro One’s network is Ring 7, which is entirely built using third-party provided fibres.

Considering performance and reliability of third-party fibre, and the risk they pose for critical PSTS that support the operation of the Bulk Power System, the proposed investments are put forth to reduce reliance on third party acquired fibre. These projects will provide the improved reliability of Hydro One-owned OPGW-based fibre facilities and leverage opportunities within the transmission lines capital sustainment programs.

The existing SONET (and the future technology that replaces it) require ring architecture in order 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 4,000 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 is primarily comprised of (i) OPGW technology with strands of fibre embedded inside of the shieldwire mounted on top of high-voltage transmission structures and (ii) All-Dielectric Self-Supporting (ADSS) fibre cable that is attached to towers or poles typically below the phase conductors, with a small percentage being attached to low-voltage wood poles located along roadways and/or railways. Due to installation issues experienced with ADSS, most of Hydro One's ADSS installations have been removed and replaced with more reliable OPGW links.

Hydro One also utilizes a large number of leased metallic copper-based circuits from Telcos for communication-aided protection schemes at many transmission stations. 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. Telco carriers no longer abide by the performance parameters outlined in their Service Level Agreements (SLAs) with Hydro One, citing equipment obsolescence.

Of all PSTS component failures between 2000-2015, comprising 9615 components, leased circuits represented 16% of those failures (1614 instances). Although the failure rate may not appear significant by itself, the fact that critical tele-protection and SCADA applications utilize these leased circuits requires Hydro One to minimize failure rates so that the service remains operational.

Table 1 - Outage Statistics PSTS Circuit Type
(Circuits Carrying Critical Tele-protection Applications)

Item	2016	2017	2018	2019	2020	Comment
Number of Tickets logged by ITMC	98	105	104	118	101	ITMC: Integrated Telecom Management Centre
Total Outage time (Hours)	5,400	6,623	5,511	9,496	7,404	
Average Outage time per instance (Hours)	54	66	59	87	73	

Table 1 shows a sampling of trouble tickets (from a sample of 449 circuits from one carrier) for a vendor over a five-year period (2016-2020). In 2016, there were 98 outages with each outage averaging 54 hours. A worsening trend of increasing outage duration is shown over the five years. Because a single circuit can have multiple outages, the 98 outages shown in 2016 does not equate to 21% (98/449) circuits having had an outage in that year. Instead, the 2016 figures show that for a total of 5,400 hours, the tele-protection function required for a power transmission line to be energized was not available and operators had to rely on system backup or de-energize one or multiple associated transmission lines.

In addition, the main provider of dedicated leased circuits to Hydro One has indicated that these circuits will be decommissioned in the near future, but has yet to provide a termination of service date. This will put the leased circuits - over which critical tele-protection applications operate - at risk of being made obsolete. In the US, some carriers have already provided a sunset clause to US utilities. Telco-based leased facilities must be removed or replaced in favour of Hydro One owned facilities to maintain or restore performance.

C. INVESTMENT DESCRIPTION

The projects described below aim to maintain or restore the reliability of Hydro One's existing power system telecom network by replacing third-party fibre and legacy telco leased circuits and metallic cable facilities with OPGW fibre. At the conclusion of the project descriptions, Table 2 provides a listing of each project's net cost and projected in-service year.

Telecom Infrastructure-Leaside x Downtown GTA

OPGW installation between Leaside TS and Don Fleet Junction on one of the lines H1L/H3L, H6LC, H8LC for 6 km will provide the necessary backbone link to connect various substations in the Toronto area back to Leaside TS. This investment will allow the removal of a number of legacy leased circuits in the Toronto area in favor of a dedicated, Hydro One owned, fibre based infrastructure.

Macksville Junction x Longwood L24L OPGW

The shieldwire on L24L line is being replaced (2021) with OPGW fibre in segments from Macksville Junction. This investment is intended to provide full end-to-end OPGW connectivity between Longwood SS and Lambton TS and to replace segments not completed by the aforementioned L24L line work. This investment covers the installation of 19 km of OPGW. This investment will allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities and provides a second OPGW path for Longwood SS, allowing the removal of a digital microwave path between Buchanan TS and Longwood SS.

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 a third-party fibre installed on wood pole 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 the communication reliability on SONET Ring 7.

Martindale TS x Hanmer SS X25S OPGW

Third-party fibre cable is currently in place for both main and alternate paths between Martindale TS and Hanmer SS. Over the last ten years, one or the other of these leased fibre services has failed due to cold weather conditions. This investment is intended to replace the failing third-party fibre with more reliable OPGW-based fibre to be installed on line X25S between Martindale TS and Hanmer SS. This will provide a more reliable main path between Martindale TS and Hanmer SS in the Sudbury area.

Martindale TS x Hanmer SS X26S OPGW

This investment is a complement to the X25S OPGW installation and provides a geographically-diverse OPGW-based fibre link on X26S (which is located east of Martindale) between Martindale TS to Hanmer SS, replacing a leased third-party fibre link.

Martindale x Widdifield SS Completion of OPGW Path

Taking advantage of synergies by leveraging the transmission line shieldwire replacement program, Hydro One will be installing 80 km of OPGW between Martindale TS and Widdifield SS. The Martindale TS to Widdifield SS OPGW link project covers installation of the remaining 56 km of OPGW on line H24S East of Martindale TS, towards Widdifield SS. Once the 80 km and 56 km paths are both completed, the end-to-end fibre path from Martindale TS to Widdifield SS (between Sudbury and North Bay) will allow the replacement of failure-prone third-party IRU fibre on Ring 7 with Hydro One-owned highly reliable fibre facilities.

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 for full end-to-end connectivity. This investment will allow the legacy Telco metallic circuits that provided 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.

Pembrooke TS x Barrett Chute SS OPGW

This investment will allow the legacy Telco metallic circuits and obsolete PLC equipment that provided 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, 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 planned OPGW allow provision of a geographically-diverse, redundant protection and SCADA system which replaces unreliable leased Telco circuits and analog PLC systems.

Kent TS x Chatham SS OPGW Installation

This investment will allow the legacy third-party fibre and telco metallic circuits that provided communications for protection and SCADA systems in the Chatham and Belle River area to be replaced with more reliable, OPGW-based, fibre systems. The investment has two components: 1) Installation of 8 km of OPGW between Chatham SS to Kent TS, to replace third-party fibre, and 2) Installation of 21 km of new OPGW from Woodslee Junction to Belle River TS (5 km) and Lauzon TS (16 km) to replace a number of leased metallic services as well as third-party fibre. This investment leverages new OPGW installations currently planned from Woodslee Junction to Kingsville TS in 2021-2022 as part of the shieldwire replacement project.

Preston x Cedar x Detweiler OPGW

This investment will allow the legacy telco metallic circuits that provide communications for protection and SCADA systems in the Kitchener/Guelph area to be replaced with more reliable, OPGW-based, fibre systems. An additional 40 km length of OPGW fibre cable will be installed. This installation will connect to existing OPGW fibre between Cedar TS and Detweiler TS to form a geographically redundant fibre network. It will also allow the removal of a number of legacy leased circuits in the area in favor of dedicated, Hydro One owned, fibre based infrastructure.

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 overall. This investment will use the existing and new OPGW-based fibre on a number of lines emanating from Buchanan TS to establish a geographically diverse fibre optic network for protection and SCADA applications. Due to the unavailability of lines, two leased third-party fibre links - each less than 5 km - would also be required in order to make the design fully redundant. This installation will allow the removal of ageing metallic infrastructure and legacy telco circuits.

London Area East OPGW Infrastructure (Salfrod Junction x Ingersoll)

The area of Ingersoll and Commerce Way is home to a number of important automotive and associated manufacturing facilities. These large customers would benefit from improvements in their protection and SCADA facilities. OPGW fibre currently connects Ingersoll TS to Commerce Way TS and a dedicated, licensed microwave link connects Ingersoll TS back to Buchanan TS. This investment will provide an additional 9 km length of OPGW fibre from Buchanan TS to Ingersoll TS and its terminations, allowing the removal of the old microwave system link. This investment will also allow the removal of a number of legacy leased circuits in the area in favor of dedicated, Hydro One owned, fibre based infrastructure.

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, a distance of 70 km, to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. These third-party facilities experienced a number of unexpected failures from 2015 to 2020 resulting in loss of redundant protection circuits. The expected benefits are improved communications reliability for protection and SCADA applications by reducing the frequency of Protection and Control staff dispatch due to failure of third-party fibre facilities.

OPGW Installation (Horning Mt x Burlington)

This investment provides a backup fibre path to serve multiple transformer stations in the Middleport, Hamilton Beach and Burlington area. In addition, it will replace a number of legacy telco leased metallic circuits and old dedicated metallic cable infrastructure serving as telecom media in the South West Niagara/Middleport area. The new fibre installations will provide an end-to-end backup fibre path from Middleport to Hamilton Beach and Burlington.

OPGW Installation (Stratford x Detweiler)

This investment will allow the third-party leased fibre optic facilities that are currently leased through Hydro One Telecom and provide communications for protection and SCADA systems between Stratford TS and Detweiler TS to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The aforementioned third-party facilities experienced a number of unexpected failures from 2010 to 2020 resulting in loss of redundant protection circuits in this important telecom corridor. The expected benefits are improvement of communications reliability for protection and SCADA applications and reduction of the frequency of Protection and Control staff dispatch due to failure of third-party fibre facilities.

OPGW Installation (Detweiler TS x Buchanon TS)

This investment will provide a backup, fibre-based, protection path for a number of 230 kV and 115 kV transmission lines between Buchanan TS and Detweiler TS and allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The expected benefits are improvement of communications reliability for protection and SCADA applications, reducing dependence on legacy leased circuits and avoid the need for upgrades to Telco entrances at these stations.

OPGW Riverside Junction x Manby TS

This investment will provide a backup, fibre-based, protection path for a number of 230 kV and 115 kV transmission lines in the Metropolitan Toronto area. It builds on the existing fibre connectivity between Strachan TS x Riverside Junction and other investments in the Toronto area to provide a diverse path between Leaside TS and Manby TS. The investment involves removing a number of legacy Toronto Hydro and leased Telco metallic circuits that provide communications for protection and SCADA systems to be replaced 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.

Peterborough Dobbin T31H OPGW Installation

This investment intends to connect Ottonabee TS to Dobbin TS in the Peterborough area to create an end-to-end fibre path serving a number of 230 kV transmission lines. This investment will allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The expected benefits are improvement of communications reliability for protection and SCADA applications, avoiding the need for upgrades to Telco entrances at these stations and avoiding upgrades to PLC systems in Eastern Ontario.

Kingston Area OPGW Installations

This investment is intended to install a total of 17 km of additional OPGW fibre cable to Frontenac TS and Kingston Gardiner TS, both in the Kingston area and builds on recently installed OPGW to connect these stations to the existing fibre-based power system telecom network. This investment will allow the legacy Telco metallic circuits and dedicated underground metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The expected benefits are improved communications reliability for protection and SCADA applications, reduce dependence on legacy leased circuits and avoid the need for upgrades to Telco entrances at these stations.

D5A Cumberland Junction to St. Isidore Install New OPGW Fibre

This investment will install 47 km of new OPGW from Cumberland Junction to St. Isidore TS and builds on existing OPGW to connect St. Isidore TS to Hawthorne TS. Currently St. Isidore TS is served by a telco facility as well as obsolete PLC facilities. Both the leased telco facilities and PLC have experienced failures in the recent past. This investment will allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The expected benefits are improvement of communications reliability for protection and SCADA applications, avoiding the need for upgrades to Telco entrances at these stations, and avoiding upgrades to PLC systems in Eastern Ontario.

Port Colborne TS to Crowland TS OPGW Connectivity to Allanburg TS

This investment builds on existing OPGW investments in Southwest Niagara, however an end-to-end fibre path serving the needs of line protection and SCADA is required. Installation of new OPGW on two lines (5 km and 16 km) will provide a necessary end-to-end fibre path for Port Colburne TS, Crowland TS and Allanburg TS. This investment will allow the legacy Telco metallic circuits that provided communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities. The expected benefits are improvement of communications reliability for protection and SCADA applications, reduce dependence on legacy leased circuits and avoid the need for upgrades to Telco entrances at these stations.

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 installation of OPGW fibre will complete the connection from Murray TS to Allanburg TS. This investment will allow a number of failing legacy Telco metallic circuits as well as dedicated metallic cables that provide communications for protection and SCADA systems to be replaced 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.

Claireville TS x Beaverton TS OPGW

Claireville TS to Beaverton TS OPGW link investment aims to install approximately 105 km of OPGW fibre on lines from Claireville TS to Brown Hill TS and on lines from Brownhill TS to Beaverton TS. The communication for these 230kV Bulk Power System lines has experienced reliability degradation due to the high failure rates of Telco legacy metallic circuits. The investment is intended to restore the reliability of existing power system telecom services by installing Hydro One owned fibre facilities to replace Telco legacy metallic-based communication circuits.

Ottawa Ring 9 Fibre Infrastructure Development

This investment is a multi-year investment intended to improve the telecom infrastructure supporting protection function on 115 kV lines serving OPG hydraulic generating stations west of Ottawa as well as to improve the reliability of SONET Ring 9 by providing the much needed geographical diversity through new, more reliable, OPGW-based fibre installations. This investment will allow a number of failing legacy Telco metallic circuits as well as dedicated metallic cables that provide communications for protection and SCADA systems to be replaced with modern, fibre-based, Hydro One-owned telecom facilities.

A summary of expenditures for the investments described above is provided in Table 2:

1 **Table 2 - Investment Summary ($ Millions)**

Circuits	Investment Description	2023-2027 Net Expenditures	In-Service Year
H1L,H3L,H6LC, H8LC	Telecom Infrastructure-Leaside TS x Downtown GTA	4.4	2026
L24L	Macksville Junction x Longwood L24L OPGW	1.4	2024
S2B	Martindale TS by Algoma TS OPGW link	9.5	2026
X25S	Martindale x Hanmer X25S OPGW	2.3	2025
X26S	Martindale x Hanmer X26S OPGW	2.6	2025
H24S	Martindale x Widdifield Completion of OPGW Path	3.9	2024
A4H	Ansonville x Hunta A4H Completion of OPGW	1.6	2023
X2Y, X1P, W3B	Pembrooke TS x Barrett Chute SS OPGW	12.2	2026
L28C/L29C/K2Z	Kent x Chatham OPGW Installation	1.4	2025
F11C/D7F/D9F	Preston x Cedar x Detweiler OPGW	7.9	2028
W36/W37/W5NL/W6NL/W2S/N21W	London Area West Telecom OPGW Infrastructure Installation	3.2	2029
M31W/M32W	London Area East OPGW Infrastructure (Salfrod Junction x Ingersol)	3.7	2027
S2S	OPGW Installation (Stayner x Owen Sound)	9	2028
B3/B4	OPGW Installation (Horning Mt x Burlington)	4.3	2026
B22D/B23D	OPGW Installation (Stratford x Detweiler)	4.2	2030
D4W/D5W	OPGW Installation (Detweiler x Buchanon)	3.2	2030
K13J/K14J	OPGW Riverside Junction x Manby TS	0.6	2028
P3S/T31H	Peterborough Dobbin_T31H OPGW Installation	2.2	2024
X2H/Q3K	Kingston Area OPGW Installation	3.6	2025
D5A	D5A Cumberland Junction St Isidore Install New OPGW fibre	7.5	2026
C2P, A6C,A7C, D3A	Port Colborne to Crowland OPGW Connectivity to Allanburg TS	3	2024
Q2AH/Q4N/A36N	Hamilton/Niagara Area new OPGW Investments	4.7	2026
H82V/H83V, B88H/B89H, M80B, M81B	Claireville TS by Beaverton TS OPGW link	7.5	2025
W6CS,M32S, C7BM,W3B	Ottawa Ring 9 Fibre Infrastructure Development	13.4	2025
TOTAL		**117.3**	

D. OUTCOMES

D.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment arranged in the categories in the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 3 - 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 degraded 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 performance standards under NERC TPL-001.
Financial Performance	• Mitigate OM&A costs associated with the relatively high failure rates of third-party fibre cables and metallic Telco leased circuits.

E. EXPENDITURE PLAN

Table 4 below summarizes historical and projected spending at the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in "Forecast 2028+" are investment costs forecast in 2028 and beyond.

Table 4 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	18.1	30.4	30	32.7	21.8	11.4	19.4	168.7
Less Removals	0.9	1.9	2.3	2.3	1.6	0.9	1.8	11.6
Capital and Minor Fixed Assets	**17.2**	**28.5**	**27.8**	**30.4**	**20.1**	**10.5**	**17.6**	**152.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**17.2**	**28.5**	**27.8**	**30.4**	**20.1**	**10.5**	**17.6**	**152.1**

The factors influencing the cost of the investment include:

- Planned costs are based on past OPGW deployment costs.
- Transmission line outage availability will have a direct impact on schedules.
- Hydro One will follow its established estimating process and project management practices to minimize controllable costs.

F. 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 facilities and legacy Telco metallic 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”

This alternative is preferred as it will maintain or restore robust and reliable communications throughout Hydro One’s power system telecom network. The installation of new OPGW fibre will replace the use of Telco metallic cables that currently serve various protection and SCADA facilities. It will also allow Hydro One to avoid the need to upgrade Telco entrances and existing standalone communication systems.

Additional OPGW investments in areas throughout the province – as presented in this document - 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 also will 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 provided facilities.

G. 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 investment to ensure that outages are available when required and disruptions to customers are minimized. The availability of resources and other competing investments requiring similar resources are also a risk to investment completion. Hydro One will develop a detailed project and resource plan in order to ensure resources are available when needed.

1 **APPENDIX A – DESCRIPTION OF INVESTMENTS**

Circuits	Investment Description	Investment Start Year	In-Service Year
H1L,H3L,H6LC, H8LC	Telecom Infrastructure-Leaside TS x Downtown GTA	2023	2026
L24L	Macksville Junction x Longwood L24L OPGW	2023	2024
S2B	Martindale TS by Algoma TS OPGW link	2022	2026
X25S	Martindale x Hanmer X25S OPGW	2023	2025
X26S	Martindale x Hanmer X26S OPGW	2023	2025
H24S	Martindale x Widdifield Completion of OPGW Path	2022	2024
A4H	Ansonville x Hunta A4H Completion of OPGW	2021	2023
X2Y, X1P, W3B	Pembrooke TS x Barrett Chute SS OPGW	2023	2026
L28C/L29C/K2Z	Kent x Chatham (OPGW Installation-	2022	2025
F11C/D7F/D9F	Preston x Cedar x Detweiler OPGW	2024	2028
W36/W37/W5NL/W6NL/W2S/N21W	London Area West Telecom OPGW Infrastructure Installation	2025	2029
M31W/M32W	London Area East OPGW Infrastructure (Salfrod Junction x Ingersol)	2025	2027
S2S	OPGW Installation (Stayner x Owen Sound)	2024	2028
B3/B4	OPGW Installation B3/B4 (Horning Mt x Burlington)	2023	2026
B22D/B23D	OPGW Installation (Stratford x Detweiler)	2025	2030
D4W/D5W	OPGW Installation (Detweiler x Buchanon)	2025	2030
K13J/K14J	OPGW Riverside Junction x Manby TS	2026	2028
P3S/T31H	Peterborough Dobbin_T31H OPGW Installation	2022	2024
X2H/Q3K	Kingston Area OPGW Installations	2023	2025
D5A	D5A_Cumberland_junction_St_Isidore Install New OPGW fibre	2022	2026
C2P, A6C,A7C, D3A	Port Colborne to Crowland OPGW Connectivity to Allanburg TS	2022	2024
Q2AH/Q4N/A36N	Hamilton/Niagara Area new OPGW Investments	2023	2026
H82V/H83V, B88H/B89H, M80B, M81B	Claireville TS by Beaverton TS OPGW link	2021	2024
W6CS,M32S, C7BM,W3B	Ottawa Ring 9 Fibre Infrastructure Development	2021	2025

APPENDIX B – DETAILED INVESTMENT COSTS

The investments proposed in this ISD are complex, and are undertaken over several years based on the Capital Project Delivery Model discussed in TSP Section 2.10. 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 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.

	Station/Circuit Name/ Designation	EB-2019-0082	Scope	Type	Net Capital Investment ($ Millions)							In Service Year
					2023	2024	2025	2026	2027	23-27 Total	Proj. Total	
T-SR-17.1	H1L,H3L, H6LC, H8LC		Telecom Infrastructure- Leaside TS x Downtown GTA	P	1.6	1	1.3	0.5	0	4.4	4.4	2026
T-SR-17.2	S2B	SR-28	Martindale TS by Algoma TS OPGW link	P	1.7	3.8	3.2	0.8	0	9.5	9.7	2026
T-SR-17.3	H24S	SR-28	Martindale x Widdifield Completion of OPGW Path	P	3.3	0.6	0	0	0	3.9	5.4	2024
T-SR-17.4	A4H		Ansonville x Hunta A4H Completion of OPGW	P	1.6	0	0	0	0	1.6	4.2	2023
T-SR-17.5	X2Y, X1P, W3B		Pembrooke TS x Barrett Chute SS OPGW	P	0.5	2.2	6.1	3.4	0	12.2	12.2	2026
T-SR-17.6	F11C/D7F/D9F		Preston x Cedar x Detweiler OPGW	P	0	0.5	3.1	3.2	1.1	7.9	8.4	2028
T-SR-17.7	W36/W37/W5 NL/W6NL/W2S/ N21W		London Area West Telecom OPGW Infrastructure Installation	P	0	0	0.2	1.5	1.5	3.2	5.6	2029
T-SR-17.8	M31W/ M32W		London Area East OPGW Infrastructure (Salfrod Junction x Ingersol)	P	0	0	0.5	2.3	0.9	3.7	3.7	2027
T-SR-17.9	S2S		OPGW Installation (Stayner x Owen Sound)	P	0	0.5	2.2	3.4	2.9	9.0	10.1	2028

	Station/Circuit Name/ Designation	EB-2019-0082	Scope	Type	Net Capital Investment ($ Millions)							In Service Year
					2023	2024	2025	2026	2027	23-27 Total	Proj. Total	
T-SR-17.10	B3/B4		OPGW Installation B3/B4 (Horning Mt x Burlington)	P	0.8	1.7	1.2	0.6	0	4.3	4.3	2026
T-SR-17.11	B22D/B23D		OPGW Installation (Stratford x Detweiler)	P	0	0	0.5	2.1	1.6	4.2	7.1	2030
T-SR-17.12	D4W/D5W		OPGW Installation (Detweiler x Buchanon)	P	0	0	0.5	0.5	2.2	3.2	12.7	2030
T-SR-17.13	X2H/Q3K		Kingston Area OPGW Installations	P	0.4	2.3	0.9	0	0	3.6	3.6	2025
T-SR-17.14	D5A		D5A_Cumberland_junction_St_Isidore Install New OPGW fibre	P	2.1	2.5	2.1	0.8	0	7.5	7.9	2026
T-SR-17.15	C2P, A6C,A7C, D3A		Port Colborne to Crowland OPGW Connectivity to Allanburg TS	P	1.3	1.7	0	0	0	3.0	3.4	2024
T-SR-17.16	Q2AH/Q4N/ A36N		Hamilton/Niagara Area new OPGW Investments	P	0.4	1.3	2.1	0.9	0	4.7	4.7	2026
T-SR-17.17	H82V/H83V, B88H/B89H, M80B, M81B	SR-28	Claireville TS by Beaverton TS OPGW link	P	5.3	2.2	0	0	0	7.5	11.6	2024
T-SR-17.18	W6CS,M32S, C7BM,W3B	SR-28	Ottawa Ring 9 Fibre Infrastructure Development	P	5.9	4.1	3.4	0	0	13.4	20.4	2025
T-SR-17.19			Investments which each have a value less than $3M (6 investment NET totals combined)	P	3.6	3.3	3.1	0.2	0.3	10.5	12.7	Multiple
	Total				**28.5**	**27.7**	**30.4**	**20.2**	**10.5**	**117.3**	**152.1**	

Witness: JABLONSKY Donna

T-SR-18	C5E/C7E UNDERGROUND CABLE REPLACEMENT
Primary Trigger:	Condition
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	38.3	23.7	4.6	0.1	-	66.7

Summary:

This investment involves the replacement of 7.2 circuit km of 115 kV low-pressure oil-filled underground cables with cross-linked polyethylene (XLPE) type cable. These oil-filled cables are in poor condition. The primary trigger of the investment is condition. The investment is expected to maintain reliability and eliminate the risk associated with operating oil-filled cables.

A. OVERVIEW

Hydro One circuits C5E and C7E from Esplanade Transformer Station (TS) to Terauley TS are underground transmission cables that provide a critical supply to Toronto's downtown core and are routed partially along Lake Ontario. These circuits were put into service in 1959 and are in poor condition. Through a detailed condition assessment, Hydro One has determined that these underground circuits require replacement.

This investment, the Power Downtown Toronto (PDT) Project, involves the replacement of 7.2 circuit km of the 115 kV low-pressure oil-filled underground cables with 5 circuit km of cross-linked polyethylene (XLPE) type cable following an alternate route. The replacement will encompass both the C5E and C7E circuits from Esplanade to Terauley TS and involves construction of an underground tunnel to house the replacement cables. The tunnel will be approximately 3 m in diameter, 2.5 km in length, have a depth of 25 m.

Due to their poor condition, location and component obsolescence, these underground cables require replacement. Hydro One has evaluated various alternatives for the investment, as described below, and concluded that replacing the poor condition oil-filled underground transmission cables with the XLPE type cables is the most effective and efficient undertaking. The investment is estimated to be $66.7M over the 2023-2027 Test period and is expected to be in-serviced in 2025.

B. NEED AND OUTCOME

B.1 INVESTMENT NEED

Hydro One circuits C5E and C7E from Esplanade TS to Terauley TS (7.2 circuit km or 3.6 route km) are 115 kV paper-insulated low-pressure oil-filled underground transmission cables that provide a critical supply to Toronto's downtown core and are routed partially along Lake Ontario. These circuits were put into service in 1959 and are in poor condition. Through a detailed condition assessment, Hydro One has determined that these underground circuits require replacement.

The cable jackets have been tested and were found to be in deteriorated condition, confirming the need for cable replacement. Deteriorated jackets can adversely affect cable performance by allowing circulating current flow, leading to overheating and therefore damaging the insulation, accelerating corrosion and oil leaks. Analysis of the paper insulation was performed, and the results were indicative of thermal aging/degradation by approximately 25% beyond what is normally seen in comparable Hydro One cables. Thermally degraded paper insulation can lead to cable failure during faults, resulting in prolonged circuit outages and negative environmental impact due to the potential release of oil. In addition to the oil pressure system being susceptible to oil leaks, the cable type is obsolete, with few spare part suppliers. The deteriorated condition, risk of cable failure and oil leaks may result in loss of supply and an adverse environmental impact that will increase with time unless the cables are replaced.

Interruption or failure of C5E and C7E can negatively impact power supply to Toronto hospitals along University Avenue, the University of Toronto, Toronto City Hall, the Toronto financial district and tourist/entertainment areas. From an environmental perspective, approximately 2.6 circuit km of cable is directly buried under Queens Quay along Lake Ontario. If a leak occurs along Queens Quay, it would likely be confined to the surrounding soil. However, if the leak is significant enough to contaminate ground and/or surface water (Lake Ontario), the remediation will be very challenging and costly, requiring equipment such as booms and wells.

Furthermore, utilities are shifting away from the use of oil-filled to XLPE cable systems and manufacturers have been reducing production and support for oil-filled cables. The limited number of manufacturers may lead to increased delivery times and prices.

C. INVESTMENT DESCRIPTION

The investment scope includes the following:

- Construction of an underground tunnel between Terauley and Esplanade TS. The tunnel would be approximately 3 m in diameter, 2.5 km in length, have a depth of 25 m below ground and be within the City of Toronto's existing road allowances.
- Construction of two tunnel access shafts:
  - Entry Shaft – The entry shaft located at Esplanade TS, will be approximately 12 m in diameter and will be the entry point for the tunnel boring machine (TBM).
  - Exit Shaft – The exit shaft located at Terauley TS will be approximately 8 m in diameter and will be the exit point for the TBM.
- Installation of 5 km of 230 kV insulated XLPE cables (two circuits of 2.5 km each). The cables will continue to operate at 115 kV, but their 230 kV rating is required to accommodate high temporary over-voltages during fault conditions, thus reducing the likelihood of damage requiring repair and improving long-term reliability.
- Replacement of 12 terminations, arresters and associated components at Terauley and Esplanade TS.
- Installation of on-line temperature and partial discharge monitoring systems.
- Adjustment of line protections due to the change in cable type and length.
- Decommissioning of the existing oil-filled cables and associated components between Terauley TS and Esplanade TS.

D. OUTCOMES

D.1 OEB RRF OUTCOMES

As a result of the investment, Hydro One will maintain reliability and minimize future costs through the replacement of the oil-filled cables on circuits C5E and C7E with modern XLPE cable. This will eliminate the risks to reliability associated with operating poor condition assets, and eliminate the environmental and obsolescence risk associated with operating oil-filled cables. The use of XLPE cables will also eliminate the preventative maintenance and repair costs associated with oil-filled cables. In addition, by installing the replacement cables in a tunnel at a depth of approximately 25m, these assets will be far below typical utility depth, reducing the need to perform field locates, which is estimated to produce some savings compared to similar surface routes.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Maintain system and customer reliability in downtown Toronto by replacing poor condition cable systems
Operational Effectiveness	• Maintain operational flexibility of supply to downtown Toronto
Public Policy Responsiveness	• Reduce risk of environmental contamination due to possible oil leaks

E. EXPENDITURE PLAN

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	41.5	38.3	24.1	4.8	0.1	-	-	108.8
Less Removals	-	-	0.4	0.2	-	-	-	0.6
Capital and Minor Fixed Assets	**41.5**	**38.3**	**23.7**	**4.6**	**0.1**	**-**	**-**	**108.2**
Less Capital Contributions	-	-	-	-	-	-	-	-
Net Investment Cost	**41.5**	**38.3**	**23.7**	**4.6**	**0.1**	**-**	**-**	**108.2**

F. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

Reactive replacement of underground cables is the “Status Quo” alternative, which means Hydro One will continue to operate and maintain the existing C5E and C7E cables and replace them upon failure. This alternative was considered and has been rejected as failure of these cables will result in 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

Planned Replacement is the preferred investment. This alternative involves planned replacement of 7.2 circuit km of poor condition 115 kV low-pressure oil-filled underground transmission cable with oil-free XLPE cable between Esplanade TS and Terauley TS. Due to their deteriorated condition and the increased risk of cable failure and oil leaks, planned replacement will mitigate risks to reliability and the environment. The replacement of the deteriorated cables will address reliability concerns associated with operating poor condition assets.

G. EXECUTION RISK AND MITIGATION

As described in TSP Section 2.10, Hydro One follows a Transmission Capital Project Delivery Model, throughout which project risks are identified and mitigation plans are implemented. The following risks can impact this investment:

- Schedule Delays: Potential schedule delays due to changes in traffic management and/or poor contractor performance. This risk will be mitigated through daily supervision and monitoring, bi-weekly schedule updates and robust language in tendering and contract documents.

- Permit and Application Delays: For example, a groundwater discharge permit is required, this is an onerous application and can take several months to obtain. To mitigate this risk, hydro-geological investigations will be conducted to support an early application. Necessary permits and approvals will be sought well in advance.
- Site Conditions During Tunnel Construction: Difficult and unanticipated ground conditions encountered during construction may lead to large cost claims from the contractor. To mitigate this risk a comprehensive geotechnical investigation along the tunnel route and at all shaft sites is currently being conducted to identify expected ground conditions. This investigation will be completed prior to construction.

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T-SS-01	**NANTICOKE TS: CONNECT HVDC LAKE ERIE CIRCUITS**
Primary Trigger:	Interconnections
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
Net Cost	0.0	0.0	0.0	0.0	0.0	0.0

Summary:

This is a non-discretionary investment in response to a Hydro One customer's request to connect its facilities to Hydro One's transmission system at Nanticoke TS. Pursuant to the Capital Cost Recovery Agreement (CCRA), all connection costs associated with this investment will be fully recovered from the customer. The current planned in-service date is Q2 2024.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to facilitate the request from Hydro One's customer, Lake Erie Connector LLC (ITC), to connect a 1,000 MW high-voltage direct current (HVDC) line between Ontario and Pennsylvania to the Ontario grid at Nanticoke TS. In accordance with section 4.1 of the OEB's Transmission System Code (TSC) and section 8 of Hydro One's Electricity Transmission License, Hydro One is required to connect customers' facilities to its transmission system upon request from a customer.

B. INVESTMENT DESCRIPTION

ITC is constructing a 117 km long, underwater 1,000 MW HVDC cable line between converter stations in Nanticoke, Ontario and Erie, Pennsylvania, USA. Short alternating current (AC) lines will connect the converter stations to the Ontario and Pennsylvania transmission systems. The proposed investment involves connecting ITC's 500kV line at Nanticoke TS. This requires the expansion of the Nanticoke TS 500kV switchyard to accommodate the connection, including the following elements:

- Extension of the 500kV main busses;
- Addition of a new 500kV diameter with two new 500kV breakers;
- Protection and control modifications to incorporate the new line; and
- Relocation of one 500kV transmission tower.

A map showing the project location in Ontario is provided below.

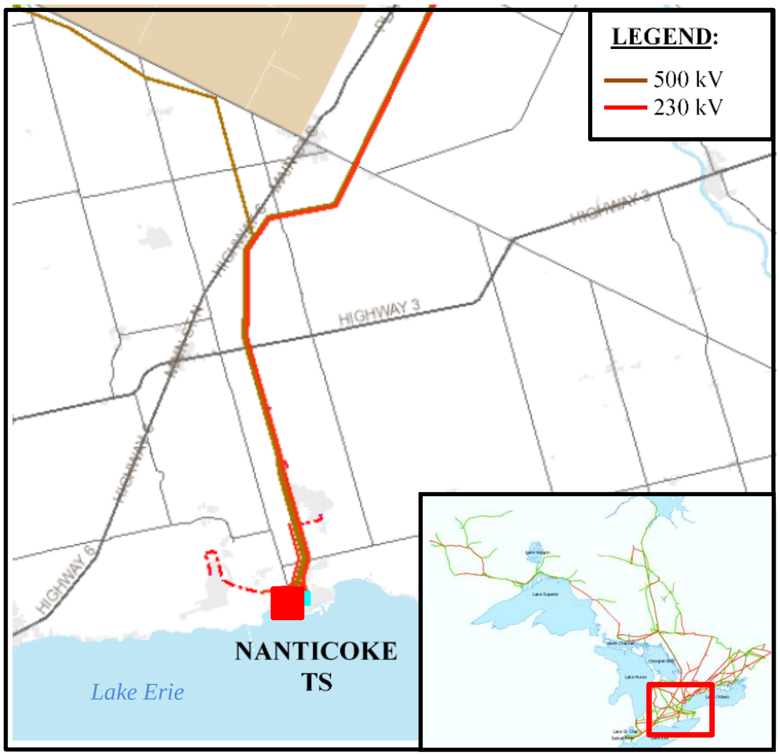

Figure 1: Nanticoke TS

The System Impact Assessment and Customer Impact Assessment have been completed for this investment. These assessments confirm that this investment will not negatively impact the reliability of the IESO-controlled grid or degrade the electricity service of the customers.

ITC has obtained the necessary approvals for its cross-border interconnection project. The National Energy Board (NEB) issued a Certificate of Public Convenience and Necessity on June 26, 2017, and the US Department of Energy granted a Presidential Permit for the investment on January 12, 2017.

Commencement of the project is subject to the signing of a Capital Cost Recovery Agreement (CCRA) with the customer. ITC has advised that its projected in-service date has been revised and the current planned in-service date is anticipated to be in Q4 2024.

C. OUTCOMES

The following table presents the anticipated outcomes of the investment:

Table 1 - Outcomes Summary

Customer Focus	• Satisfy ITC's request for connection.
Operational Effectiveness	• Increase operating flexibility of the transmission system by providing a new interconnection between Ontario and Pennsylvania
Public Policy Responsiveness	• Comply with Hydro One's obligations under the TSC and its Electricity Transmission License to connect neighboring transmitters and provide customers with non-discriminatory access.

D. EXPENDITURE PLAN

This investment is non-discretionary. The investment's costs, as presented in the table below, are fully recoverable through capital contributions from ITC in accordance with the CCRA. The investment's costs and capital contribution amounts are considered preliminary, as they will be finalized once the project is placed in-service. The capital contributions will be determined as per Hydro One's Transmission Customer Contribution Policy, developed in accordance with the TSC.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have been incurred prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	3.1	10.2	4.1	0.0	0.0	0.0	-	17.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**3.1**	**10.2**	**4.1**	**0.0**	**0.0**	**0.0**	-	**17.4**
Less Capital Contributions	3.1	10.2	4.1	0.0	0.0	0.0	-	17.4
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	-	**0.0**

E. ALTERNATIVES

This investment is non-discretionary pursuant to Hydro One's obligations under the TSC and its Electricity Transmission License. As such, no alternatives were considered.

F. 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 investment, such as availability of the outage that is required to execute the work. These risks will be mitigated by setting a schedule that aligns with the outage availability. There is also a risk that the customer requirements may change resulting in a delay or cancellation of the need for this investment. 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-SS-02	ST. LAWRENCE TS: PHASE SHIFTERS REPLACEMENT
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	6.0	0.0	0.0	0.0	0.0	6.0

Summary:

This investment is required to replace the phase shifters (PS33, PSR34) at St. Lawrence TS. Phase shifter (PS33) failed in April 2018 and is no longer serviceable. Phase shifter (PSR34) has exceeded its expected service life of 40 years and is to be replaced to avoid the risk of another unexpected phase shifter failure at the intertie. The planned in-service date for this investment is Q1 2023.

The New York Independent System Operator (NYISO), the New York Power Authority (NYPA), the Ontario Independent Electricity System Operator (IESO) and Hydro One all agree that the existing interconnection is needed and that both phase shifters are required to be replaced to maintain interconnection capability.

Hydro One is obligated to provide facilities as required to maintain the reliability and integrity of its transmission system in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in a reduction of the interconnection capacity and the reliability of the Ontario – New York intertie at St. Lawrence TS.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to replace the phase shifters (PS33, PSR34) at St. Lawrence TS. These phase shifters are part of the Ontario-New York 230kV interconnection circuits (L33P/L34P) at St. Lawrence TS. Phase shifters provide an important and preferred means of achieving active power flow control in a transmission system, including enforcing power flow and rebalancing line loading. In this case, phase shifters (PS33, PSR34) are used to control flow on the Ontario-New York interconnection lines, maximize east-west transfers in Ontario and help reduce overall losses. The planned in-service date for this investment is Q1 2023.

Following a phase shifter (PS33) failure event, the New York Independent System Operator (NYISO), the New York Power Authority (NYPA), the Ontario Independent Electricity System Operator (IESO) and Hydro One discussed the future of the Ontario-New York 230kV interconnection at St. Lawrence TS. All parties agreed that the existing interconnection is still needed and that both phase shifters are required to be replaced to maintain interconnection capability.

Hydro One is obligated to provide facilities as required to maintain the reliability and integrity of its transmission system in accordance with its Transmission License and the Transmission System Code. Not proceeding with this investment would result in a reduction of the interconnection capacity and the reliability of the Ontario – New York intertie at St. Lawrence TS.

B. INVESTMENT DESCRIPTION

In response to the unavailability of phase shifter PS33 and to maintain interconnection capability on the Ontario-New York intertie at St. Lawrence TS, Hydro One plans to:

- Replace phase shifter PS33 and its associated voltage regulator transformer (R33) and disconnect switches. The new unit will have a similar rating as the existing unit but will combine the phase shifter and voltage regulator transformer functions in one unit; and
- Replace the existing phase shifter PSR34, which is a combined phase shifter and regulating transformer, as well as its associated disconnect switches. The new unit will have a similar rating as the existing unit.

To ensure that the capability of the Ontario – New York interconnection is restored as soon as possible Hydro One has placed a High Priority on this investment. The replacement of phase shifter PS33 is to be completed by 2022 and phase shifter PSR34 by 2023.

A map showing the project location is provided below.

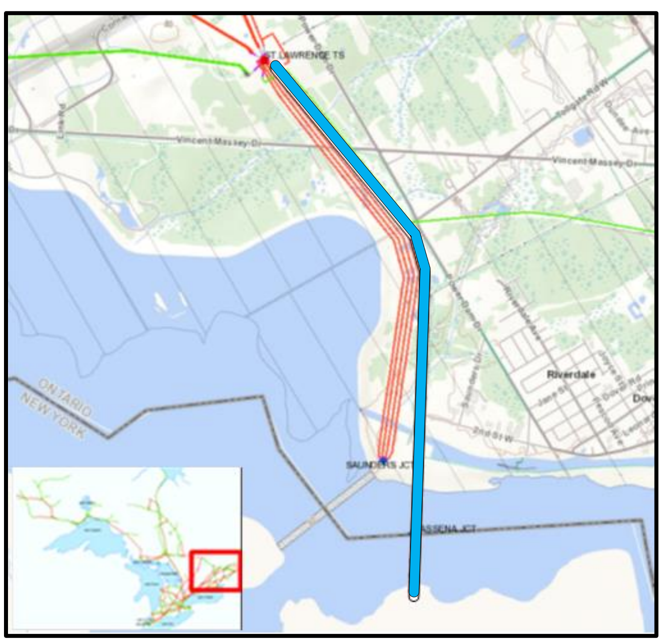

Figure 1: St. Lawrence TS

C. OUTCOMES

This investment will maintain interconnection capability between Ontario and New York.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Restore and maintain security of the bulk transmission system for reliable supply to customers.
Operational Effectiveness	• Eliminate operating constraints resulting from having only one phase shifter in-service.
Public Policy Responsiveness	• Maintain interconnection capability between Ontario and New York.
Financial Performance	• Costs will be shared equally with the NYPA. Hydro One's share of the costs will be recovered from the network rate pool.

D. EXPENDITURE PLAN

The project costs, as presented in the table below, will be shared equally between Hydro One and NYPA. Hydro One's share of the project costs will be recovered from the network rate pool as these phase shifters are network assets.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	56.2	12.0	0.0	0.0	0.0	0.0	-	68.2
Less Removals	0.4	0.0	0.0	0.0	0.0	0.0	-	0.4
Capital and Minor Fixed Assets	**55.8**	**12.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**67.8**
Less Capital Contributions	27.9	6.0	0.0	0.0	0.0	0.0	-	33.9
Net Investment Cost	**27.9**	**6.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**33.9**

E. ALTERNATIVES

There is no cost effective alternative to replacing the phase shifters (PS33 and PSR34) at St. Lawrence TS for restoring the interconnection capacity between Ontario and New York. Replacement of the two phase shifters is the preferred and recommended option.

F. 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: the procurement of the specialized and complex phase shifter equipment and availability of the outage that is required for the work to be executed. These risks will be mitigated by setting a schedule that aligns with equipment and outage availability.

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T-SS-03	MERIVALE TS TO HAWTHORNE TS: 230KV CONDUCTOR UPGRADE
Primary Trigger:	Capacity
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	9.0	0.0	0.0	0.0	0.0	9.0

Summary:

This investment involves replacing the existing conductors on the 230kV circuits M30A and M31A between Hawthorne TS and Merivale TS with a higher current-rated conductor. This investment will increase the loading capability of the M30A and M31A circuits to meet forecast future demand and facilitate increased bulk power transfers from eastern Ontario towards the GTA. In addition, reinforcement of circuits M30A and M31A will enable 1250-1650 MW of capacity imports from Quebec. The planned in-service date for this investment is Q4 2023.

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. Not proceeding with this investment would result in Hydro One not meeting its obligation as the capacity of the M30A and M31A circuits would be exceeded and bulk power system transfers limited. The IESO has requested that Hydro One undertake this investment. Hydro One has assigned it a High Priority in order to meet system needs.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to increase the loading capability of the 230kV double circuit line (M30A/M31A) between Hawthorne TS and Merivale TS. Currently the circuits are operating near capacity under summer peak load conditions supplying Ottawa loads and carrying power from eastern Ontario generation to the GTA. The planned in-service date for this investment is Q4 2023.

On February 1, 2019, the IESO provided a handoff letter[1] to Hydro One, requesting Hydro One to proceed with uprating circuits M30A and M31A. This investment will increase the circuit capacity, to meet forecast future demand and facilitate increased bulk power transfers from eastern Ontario towards the GTA. Reinforcement of circuits M30A and M31A also will enable 1250-1650 MW of capacity imports from Quebec, as identified in the 2017 Quebec interconnection study. The IESO's handoff letter indicates that enabling capacity imports from Quebec is expected to increase competition in the Ontario capacity auction, resulting in lower prices.

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. Not proceeding with this investment would result in Hydro One not meeting its obligation as the capacity of the M30A and M31A circuits would be exceeded thereby limiting flows on the bulk power system. This investment is assigned a High Priority in order to meet this obligation.

[1] IESO Letter, "Upgrading 230 kV Circuits M30/31A between Hawthorne TS and Merivale TS in Ottawa", dated February 1, 2019.

B. INVESTMENT DESCRIPTION

Hawthorne TS and Merivale TS are the two main supply stations for the Ottawa area. The flow on the 230kV circuits (M30A and M31A) connecting Hawthorne TS to Merivale TS is largely dependent on eastern Ontario generation dispatch and system demand.

The conductors comprising the two M30A and M31A 230kV circuits between Hawthorne TS and Merivale TS require upgrading to meet growing load in the Ottawa area and facilitate bulk power transfer from eastern Ontario, including eastern Ontario generation, towards the GTA. This proposed investment involves replacing the existing conductor with a two conductor bundle thereby allowing the circuit rating to be increased from 648MW to about 1080MW. A map showing the investment location is provided below.

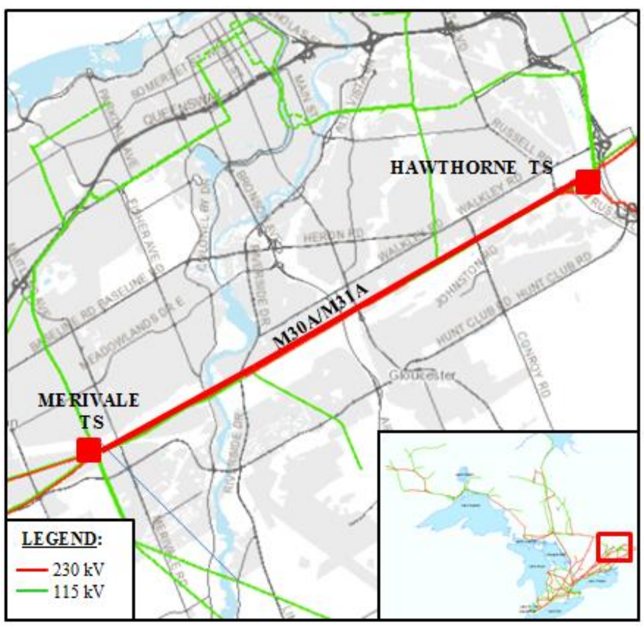

Figure 1: Map of the Investment location

The IESO's System Impact Assessment has been completed for this investment and confirms that the incorporation of these facilities will not adversely impact the reliability of the IESO-controlled grid. Hydro One's Customer Impact Assessment (CIA) was completed in Q1 2021. The final CIA has been provided to area transmission connected customers and concludes that the project is not expected to adversely impact them.

On December 2, 2020, Hydro One applied for "Leave to Construct" approval under Section 92 of the Ontario Energy Board Act (EB-2020-0265). A summary of the need, investment description, risk, and costs have been presented herein; with specific details provided in the Section 92 application. On April 22, 2021 Hydro One received OEB-approval for its "Leave to Construct" application to replace the conductors on the 230kV circuits M30A and M31A.

C. OUTCOMES

This investment will increase loading capability of the 230kV circuits between Hawthorne TS and Merivale TS to meet forecast future demand and facilitate bulk power flows from eastern Ontario, towards the GTA.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Facilitate future bulk system supply capacity in western Ottawa • Increase competition in the IESO Capacity Auction
Operational Effectiveness	• Increase operating flexibility of the transmission system by providing increase in transfer capacity
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and the Transmission System Code to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth
Financial Performance	• Costs are recovered from the network rate pool

D. 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 230kV circuits are network assets and thus no capital contribution is required from customers.

below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	10.7	10.6	0.0	0.0	0.0	0.0	-	21.3
Less Removals	0.0	1.6	0.0	0.0	0.0	0.0	-	1.6
Capital and Minor Fixed Assets	**10.7**	**9.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**19.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**10.7**	**9.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-**	**19.7**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The Status Quo option is not considered viable as the capacity of the M30A/M31A circuits would be exceeded and bulk power flow transfer would need to be limited.

ALTERNATIVE 2:

Install 230 kV underground cables (~ 11.9km) between Hawthorne TS to Merivale TS on the existing right-of-way (ROW) along with necessary terminal equipment at the two stations.

ALTERNATIVE 3:

Build a new 230kV double circuit overhead line (~ 85km) from St. Lawrence TS in Cornwall to Merivale TS and install terminal switching facilities at both stations.

ALTERNATIVE 4 (RECOMMENDED):

Replace the existing conductors of 230 kV circuits M30A and M31A between Hawthorne TS and Merivale TS with a higher current-rated conductor. The existing facilities are adequate and additional switching facilities are not required under this alternative.

While each of alternatives 2, 3, and 4 would address the need, Alternatives 2 and 3 were significantly more expensive[2] and were not considered further due to the higher costs and broader impact to the environment, landowners, and community. Alternative 4 has the lowest cost and also has the least environmental and community impact. It adequately addresses the need over the medium- and long-term, and is therefore the recommended alternative.

F. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would result from potential delays in securing the Section 92 approval. This risk has been mitigated by applying for approval under Section 92 in a timely manner and securing the necessary OEB-approval on April 22, 2021.

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. As the affected tower lines carry multiple circuits critical for supplying Ottawa, it may be challenging to schedule the necessary outages to complete the required work. These risks will be mitigated by setting a schedule that aligns with outage availability.

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[2] *See,* IESO Letter contained in footnote 1.

T-SS-04	**RICHVIEW TS X TRAFALGAR TS 230 KV CONDUCTOR UPGRADE**
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	12.6	16.4	12.1	2.4	0.0	43.5

Summary:

This investment is in response to the IESO's request to facilitate the increased bulk power flow from the west to the Greater Toronto Area (GTA). Hydro One's Richview Trafalgar TS circuits will soon be exceeding their capacity, and to address the issue, Hydro One will be replacing the existing conductor on the two double-circuit lines R14T/R17T and R19T/R21T between Richview TS and Trafalgar TS with a higher current-rated conductor. This investment is required to reduce the risk to reliability in having to acquire a large amount of capacity east of the GTA and to enable more resources to be available to meet provincial needs. The planned in-service date of this investment is Q1 2026.

In accordance with the Transmission System Code (TSC) and its Electricity Transmission Licence, Hydro One is obligated to provide facilities 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. To fulfill these obligations, Hydro One has assigned this investment a high priority.

A. NEED AND OUTCOME

The Flow East Towards Toronto (FETT) is a transmission interface that delivers electricity from the western to eastern part of Ontario. It consists of the following three paths: (a) four 500 kV circuits into Claireville TS from the west, (b) four 230 kV circuits between Trafalgar TS and Richview TS, and (c) two 230 kV circuits between Orangeville TS and Essa TS. Typically, the power transfers on this interface are in the west-to-east direction and are limited by the summer current ratings of the transmission circuits.

Supply capacity in eastern Ontario is expected to decline over the next decade, which contributes to a provincial need for capacity. Due to the limits on the transfer capability of the FETT interface, approximately 4,000 MW of that capacity will have to be sited east of the FETT interface by 2026. To reduce the amount of capacity that must be sited in eastern Ontario, the IESO requested Hydro One to upgrade the two double-circuit lines R14T/R17T and R19T/R21T between Richview TS and Trafalgar TS. As a result, this investment would reduce the risk to reliability in having to acquire a large amount of capacity in eastern Ontario and would enable more resources to compete to meet provincial needs.

Hydro One is obligated to provide facilities 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 in accordance with its Transmission License and the TSC.

B. INVESTMENT DESCRIPTION

The proposed investment involves upgrading the two double-circuit lines R14T/R17T and R19T/R21T between Richview TS and Trafalgar TS with higher current-rated conductor. Approximately 86 circuit-km of conductor is required to be replaced. As discussed above, the new facilities will increase the transfer capability of the 230kV circuits between Richview TS and Trafalgar TS.

A map showing the project location is provided below.

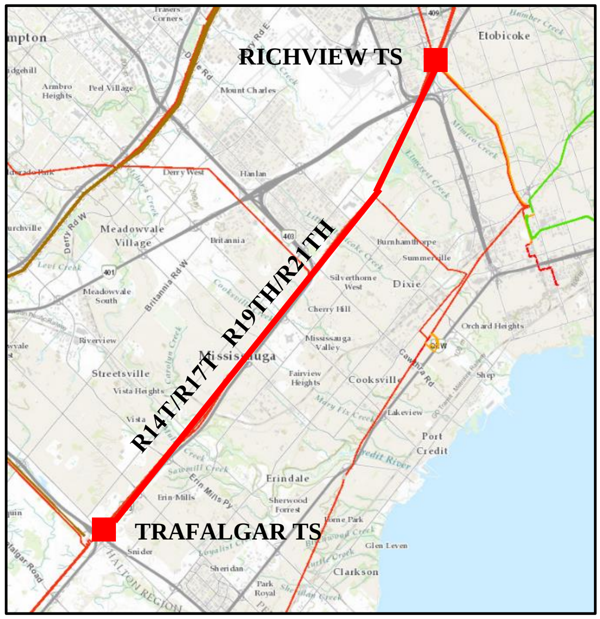

Figure 1: Map showing the project location

Hydro One is working on “Leave to Construct” approval under section 92 of the *Ontario Energy Board Act*, *1998*, as well as a Class Environmental Assessment approval under the *Environmental Assessment Act*. A summary of the need, project description, risk, and associated costs have been presented herein, with specific details to be provided in the section 92 application. All land matters will be addressed in the section 92 application. In June 2021, Hydro One filed the section 92 application with the OEB (EB-2021-0136). The application is ongoing and final approval is pending. Cost differences between this ISD and the section 92 are discussed in TSP Section 2.9.

The project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission-connected customers. The System Impact Assessment and Customer Impact Assessment will be completed to confirm the above prior to the submission of the section 92 application.

C. OUTCOMES

This investment will provide adequate bulk power system transfer capability from Southwest Ontario to the GTA.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - 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 transfer capacity.
Public Policy Responsiveness	• Comply with Hydro One's obligations under its Transmission License and the TSC to maintain the reliability and integrity of its transmission system and to reinforce or expand its transmission system as required to meet load growth. • Comply with IESO request to increase transfer capability.
Financial Performance	• Costs are recovered from the network rate pool.

D. EXPENDITURE PLAN

This investment is non-discretionary. The associated costs, as presented in the table below, will be recovered through the Uniform Transmission Rates (UTRs). In particular, given that the upgraded 230kV circuits fall within the network assets, investment costs will be recovered from the UTRs' Network Rate Pool.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	6.4	13.6	17.6	13.0	2.6	0.0	-	53.2
Less Removals	0.4	1.0	1.2	0.9	0.2	0.0	-	3.7
Capital and Minor Fixed Assets	**6.0**	**12.6**	**16.4**	**12.1**	**2.4**	**0.0**	**-**	**49.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**6.0**	**12.6**	**16.4**	**12.1**	**2.4**	**0.0**	**-**	**49.5**

E. ALTERNATIVES

Given the IESO direction and the urgency to meet the 2026 in-service date, there are no practical alternatives to the investment. As such, no other alternatives were considered.

F. EXECUTION RISK AND MITIGATION

The risks with respect to execution of this investment as planned, would be as a result of potential delays in securing the section 92 and environmental assessment approvals. These risks will be mitigated by initiating the section 92 application process and environmental assessment process in a timely manner.

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T-SS-05	MERIVALE TS: ADD 230/115KV AUTOTRANSFORMERS
Primary Trigger:	Regional planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	25.0	30.0	22.0	0.0	0.0	77.0

Summary:

This investment involves the installation of a 250MVA, 230/115kV autotransformer at Merivale TS and the modification and expansion of the existing 230kV and 115kV switchyards at the station to incorporate the new autotransformer. The investment is required to increase the 230/115kV transformation capacity at Merivale TS to support the continued load growth in the Ottawa West 115kV area as identified in the Greater Ottawa area Regional infrastructure plan and the IESO's Ottawa Integrated Regional Resource Plan. The planned in-service date of this investment in Q2 2025.

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.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to increase the 230/115kV transformation capacity at Merivale TS to support the continued load growth in the Ottawa West 115kV area as identified in the Greater Ottawa area Regional infrastructure plan and the IESO's Ottawa Integrated Regional Resource Plan (SPF 1.2, Attachment 3). The planned in-service date of this investment in Q2 2025.

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. Not proceeding with this investment would result in Hydro One not meeting its obligation and not addressing the need for adequate transformation capacity to supply load growth in the Ottawa West 115kV area. This investment is assigned a High Priority in order to meet this obligation.

B. INVESTMENT DESCRIPTION

In order to address the need for additional 230/115kV transformation at Merivale TS, it is proposed to install a third autotransformer at Merivale TS.

The scope of this project involves the following:

- Installation of one 230/115kV, 250MVA autotransformer and associated switching facilities at Merivale TS.
- Modification and expansion of the 230kV GIS switchyard to connect the new autotransformer.
- Modification and expansion of the 115kV switchyard to connect the new autotransformer.

A map showing the project location is provided below.

Figure 1: Map

The project is not expected to adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be completed by Q2 2022 to confirm the above expectations.

C. OUTCOMES

This investment will provide supply capacity to meet the area load growth in the Ottawa West 115kV area. The investment will prevent overloading of the existing transformers and improve reliability of supply to customers.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 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
Financial Performance	• Costs are recovered from the network rate pool

D. 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 230/115kV transformation facilities are network assets and no capital contributions are required from customers.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	3.0	25.0	30.0	22.0	0.0	0.0	-	80.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**3.0**	**25.0**	**30.0**	**22.0**	**0.0**	**0.0**	**-**	**80.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**3.0**	**25.0**	**30.0**	**22.0**	**0.0**	**0.0**	**-**	**80.0**

E. ALTERNATIVES

The following alternatives were further assessed before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

The status quo will not satisfy the need for the station expansion and increased 230kV/115kV transformation capacity at Merivale TS. This alternative is not recommended as it would result in overloading of the existing autotransformers resulting in outages to customers. For this reasons, and as noted above, the investment is non-discretionary.

ALTERNATIVE 2:

This alternative would convert 115kV circuit L2M and its load (approximately 90MW) to 230kV to reduce the loading on the Merivale TS autotransformers. This option would require expansion of the 230kV yard only. This option would also require the conversion of two (2) 115kV transformer stations to 230kV supply.

ALTERNATIVE 3:

Increase the transformation capacity at Merivale TS by installing two (2) 230kV/115kV autotransformers in parallel with the existing ones. This option would not require expansion of the 230kV yard since the existing 230kV autotransformer connections would be shared. However, this option would require further expansion of the 115kV yard to allow the connection of one more transformer.

ALTERNATIVE 4 (RECOMMENDED):

This alternative would install one 230/115kV 250MVA autotransformer and expand/modify the 115kV and the 230kV switchyards.

Alternative 2 would not sufficiently relieve the 230kV/115kV autotransformer loading and was not considered further. Alternative 3 would address the 230kV/115kV autotransformer loading concerns, but it requires two new autotransformers and additional upgrades to the 115kV switchyard. Alternative 4 requires 230kV switching facilities but only one autotransformer and minimizes 115kV switching facilities. It also has a lower cost than Alternative 3 and is the lowest cost of all the options that address the 230kV/115kV autotransformer loading issues. For these reasons, it is the preferred and recommended alternative.

F. 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 availability of the outages that are required for the work to be executed. This risk will be mitigated by setting a schedule that aligns with outage availability.

T-SS-06	**SOUTHWEST GTA TRANSMISSION REINFORCEMENT**
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	6.5	7.5	3.0	0.0	1.0	18.0

Summary:

This investment involves reinforcing the transmission system between Richview TS and Manby TS to increase supply capacity in the South-West GTA. The work will be done in two stages: Stage 1 covers rebuilding an idle double circuit 115kV line as a double circuit 230kV line; and Stage 2 covers the station work to be completed later in coordination with future 230kV breaker replacement work at Manby TS. The in-service date for Stage 1 work is Q2 2025 and for Stage 2 work is Q2 2030.

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. 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. This investment is assigned a High Priority in order to meet this obligation.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to increase the transfer capability between Richview TS and Manby TS to support the continued load growth in the South-West GTA area, as identified in the Toronto Regional Infrastructure Plan (Toronto RIP found at SPF Section 1.2, Attachment 8). The planned in-service date of the project is Q2 2025 for Stage 1 and Stage 2 following later in Q2 2030.

The 230kV 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. The corridor has two 230kV double-circuit lines (R1K/R2K and R13K/R15K) and one idle 115kV double-circuit line. The Toronto RIP and the IESO's Toronto Integrated Regional Resource Plan (IRRP) identified the need to reinforce the transmission system on the South-West GTA transmission corridor by rebuilding the existing idle 115kV transmission line as a new 230kV double circuit line and connecting it to Manby TS and Richview TS.

In Q4 2020 the IESO initiated a study addendum to the Toronto IRRP to explore the impact of COVID-19 and energy efficiency programs on the timing of the need and preferred alternatives for the investment. Completion of this Addendum is expected in Q3 2021. Hydro One's expectation is that the study will confirm the planned date for the work.

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. Not proceeding with this investment would result in Hydro One not meeting its obligation and not addressing the need to provide adequate transmission capacity to supply load growth in the South west GTA area. This investment is assigned a High Priority in order to meet this obligation.

B. INVESTMENT DESCRIPTION

The proposed project involves reinforcing the transmission system on South-West GTA transmission corridor. Hydro One proposes to execute the project in two stages. Stage 1 will address the line work and Stage 2 will address the station work in order to coordinate with future 230kV breaker replacement work at Manby TS, as follows:

Stage 1: Line Work (Planned In-Service date is Q2 2025)

- Rebuild the existing 6.5 km idle 115kV double-circuit line as a 230kV double-circuit line;
- Connect the new 230kV conductors in parallel with existing 230kV circuits (R2K and R15K) at Richview TS and Manby TS; and
- Modify the protection and control settings at Richview TS and Manby to incorporate the new line.

Stage 2: Station Work (Planned In-Service date is Q2 2030)

- Remove the parallel connections made in Stage 1 and terminate the two new circuits into Manby TS 230kV switchyard;
- Connect new circuits at the Richview TS end to two of the existing 230kV 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 below.

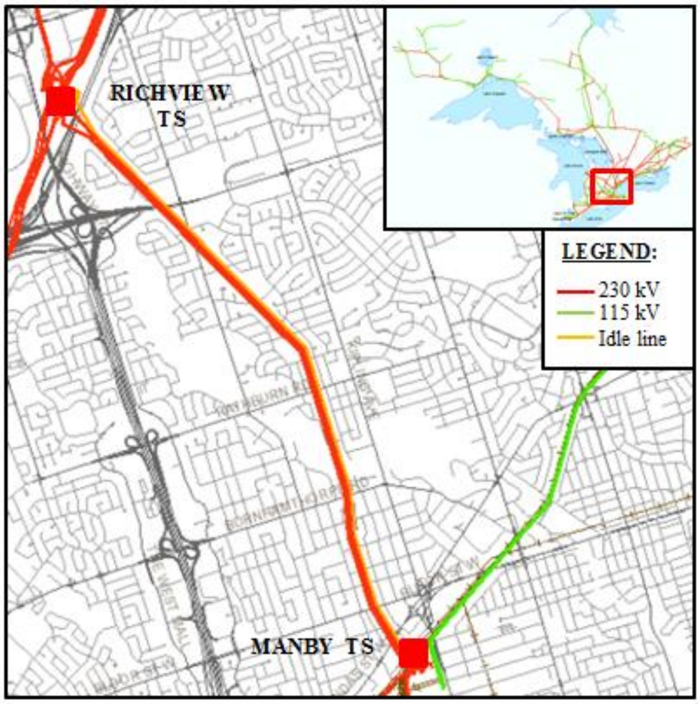

Figure 1: Map

Hydro One has initiated work under the Class Environmental Assessment process, as required under the Environmental Assessment Act, and approvals are expected to be obtained by Q3 2022.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the Ontario Energy Board Act in Q2 2022. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment have been completed.

C. OUTCOMES

This investment will provide the required increase in supply capacity to support future load growth and maintain reliability for customers in Toronto and southern Mississauga/Oakville areas.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - 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
Financial Performance	• Costs are recovered from the network rate pool

D. EXPENDITURE PLAN

This investment is non-discretionary because it has been identified as the preferred 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 230kV facilities are network assets and no capital contributions are required from customers.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in "Forecast 2028+" are investment costs forecast beyond 2028.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	6.1	6.5	7.5	3.0	0.0	1.0	18.5	42.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**6.1**	**6.5**	**7.5**	**3.0**	**0.0**	**1.0**	**18.5**	**42.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**6.1**	**6.5**	**7.5**	**3.0**	**0.0**	**1.0**	**18.5**	**42.6**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This investment is non-discretionary and is needed to ensure supply reliability for the customers in Toronto and southern Mississauga/Oakville areas and support future load growth. The status quo will not provide the necessary transmission system reinforcement on the South-West GTA transmission corridor and is therefore not a viable alternative.

ALTERNATIVE 2: UPGRADE THE TWO EXISTING DOUBLE CIRCUIT 230KV LINES

Replace the existing conductor on the existing two double circuit 230kV transmission lines R1K/R2K and R13K/R15K between Richview TS and Manby TS with higher current-rated conductor.

ALTERNATIVE 3 (RECOMMENDED): REPLACE EXISTING IDLE 115KV TRANSMISSION LINE WITH NEW 230KV DOUBLE CIRCUIT TRANSMISSION LINE

Rebuild the existing idle 115kV transmission line on the Richview to Manby transmission corridor as a 230kV double circuit transmission line and connect at Manby TS and Richview TS.

ALTERNATIVE 4: BUILD A NEW 230KV TRANSMISSION LINE BETWEEN OAKVILLE TS AND TRAFALGAR TS

Extend the existing 230kV transmission line between Cooksville TS and Oakville TS to Trafalgar TS.

Alternative 2 provides lower supply reliability and construction will be very challenging because of the difficulty in obtaining outages. Alternative 4 requires building a line on a new right-of-way resulting in a higher cost. Alternative 3 is the lowest cost alternative, and maintains reliability during the construction phase. Alternative 3 is therefore the recommended alternative. This is in line with the recommended plan in the Metro Toronto Area Regional Infrastructure Plan

F. EXECUTION RISK AND MITIGATION

The risks in executing this investment are potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment 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. These risks will be mitigated by setting a schedule that aligns with outage availability.

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T-SS-07	WEST OF CHATHAM REINFORCEMENT
Primary Trigger:	Bulk Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	8.3	20.4	5.2	0.0	0.0	33.9

Summary:

This investment involves the expansions at the terminal stations, Lakeshore Transformer Station (TS) and Chatham Switching Station (SS), to facilitate the connection of the new 230kV double circuit to (i) increase the transfer capability of the bulk transmission system west of Chatham, (ii) permit resources and bulk facilities in the region to operate efficiently and (iii) maintain existing interchange capability on the Ontario-Michigan interconnection between Windsor and Detroit. The primary trigger of the investment is the need for the reinforcement of the bulk transmission system west of Chatham to support near to mid-term electricity needs as further identified in the 2019 bulk planning study completed by the IESO. In accordance with its electricity transmission license and the Transmission System Code, Hydro One is obligated to provide facilities required to maintain the reliability and integrity of its transmission system and reinforce or expand it as required to meet load growth.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to reinforce the transmission system in the Windsor – Essex region and to increase load supply capability in the Leamington area. The existing bulk transmission in the Windsor – Essex region consists of the four 230kV circuits (C21J, C22J, C23Z and C24Z). These circuits pass through the Leamington Junction, which is the location of the new Lakeshore TS planned for completion mid-2022, and where 230kV circuits (C21J and C22J) are tapped off to supply Leamington TS and the planned transmission-connected customer stations. Hydro One Distribution has indicated a substantial increase in requests for load connection in the Leamington – Kingsville area driven by expansion in the greenhouse sector and the existing transmission system cannot support this additional load demand.

The need for transmission reinforcement has been highlighted by the IESO in the Scoping Assessment as part of its development of the 2019 Windsor-Essex Integrated Regional Resource Plan. In addition, the IESO also completed a bulk study for the area west of Chatham on June 13, 2019 titled, "*Need for Bulk Transmission Reinforcement in the Windsor-Essex Region*" that recommended the construction of a new double circuit 230kV transmission line from Chatham SS to the new Lakeshore TS. Hydro One received formal direction from the IESO in a hand-off letter on June 11, 2019 to proceed with the development of the new double circuit transmission line and associated station expansions to facilitate the required connections.

In accordance with its electricity transmission license and the Transmission System Code, 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 light of its obligations, Hydro One has assigned a high priority to this investment.

B. INVESTMENT DESCRIPTION

The proposed investment involves constructing the necessary expansions at the terminal stations, Lakeshore Transformer Station (TS) and Chatham Switching Station (SS), to facilitate the connection of the new 230kV double circuit to increase the transfer capability of the bulk transmission system west of Chatham, permit resources and bulk facilities in the region to operate efficiently and maintain existing interchange capability on the Ontario-Michigan interconnection between Windsor and Detroit. The investment is scheduled to be completed in 2025.

Included in the station expansion at Chatham SS is the extension of the high voltage 230kV busses, construction of a new 230kV diameter and installation of three (3) new 230kV circuit breakers and associated protection, control and telecommunications equipment. The proposed project also includes the necessary termination work to connect the two new 230kV transmission circuits into the station. Similarly, at Lakeshore TS, this project will result in the construction of the necessary protection, control, and telecommunications equipment and termination work to connect the two new 230kV transmission circuits into the station.

The new 230kV transmission circuits are expected to be owned by and included in the rate base of a newly licensed partnership. These assets will not form part of Hydro One’s rate base and, as such, the associated capital expenditures have been excluded from the 2023-2027 forecast. Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169). Further information may be found in Exhibit A-03-01.

A map showing the project location is provided below.

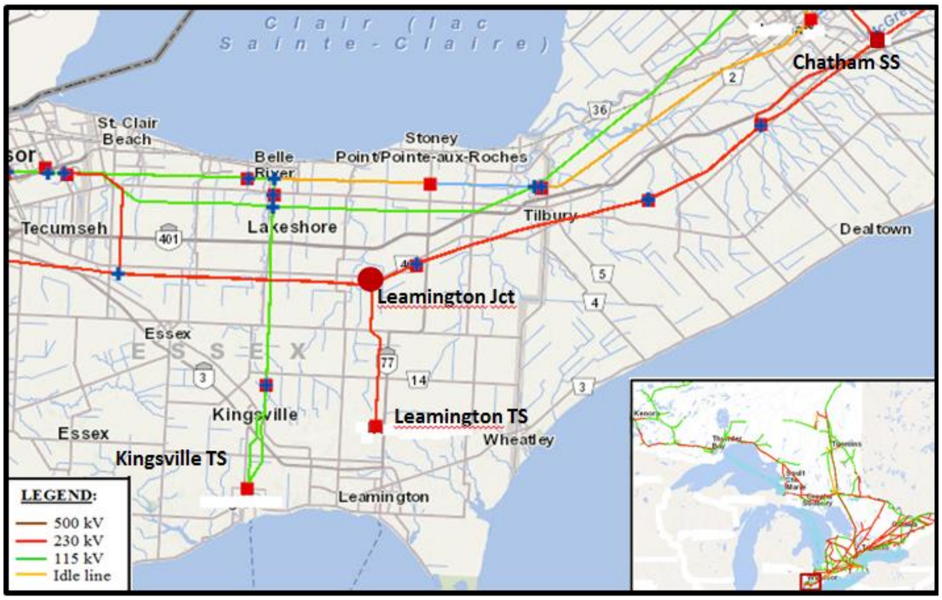

Figure 1: Map

Hydro One initiated a Class Environmental Assessment process, as required under the *Environmental Assessment Act*, for this project in Q1 2019 and approvals are expected to be obtained by Q3 2021.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the *Ontario Energy Board Act, 1998* in Q4 2021. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application. All land matters will be addressed in the Section 92 application.

Hydro One studies show that the project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be undertaken to confirm the above prior to the submission of the Section 92 application.

C. OUTCOMES

This investment will provide the required increase in supply capacity to support future load growth and maintain reliability for customers in the Kingsville-Leamington and the broader Windsor-Essex region in the near and mid-term.

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the OEB's RRF:

Table 1 - 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 • Maintain existing interchange capability on the Ontario-Michigan interconnection

D. 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 230kV facilities are network assets and no capital contributions are required from customers.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in "Forecast 2028+" are investment costs forecast beyond 2028.

Table 2 – Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	2.0	8.3	20.4	5.2	0.0	0.0	0.0	35.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**2.0**	**8.3**	**20.4**	**5.2**	**0.0**	**0.0**	**0.0**	**35.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.0**	**8.3**	**20.4**	**5.2**	**0.0**	**0.0**	**0.0**	**35.9**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This investment is non-discretionary and is needed to ensure supply reliability for the customers in the Kingsville-Leamington and broader Windsor-Essex region and support future load growth. The status quo will not satisfy the need for this investment and is therefore not a viable alternative.

ALTERNATIVE 2: CONNECT THE NEW 230KV TRANSMISSION LINE BETWEEN CHATHAM SS AND LAKESREHORE TS (RECOMMENDED)

Connect the new 230kV double circuit line between Chatham SS and Lakeshore TS. This alternative provides the required higher capacity and maintains system reliability during the construction phase and will meet near and mid-term needs for the region. This alternative will ensure compliance with the IESO’s Ontario Resource and Transmission Assessment Criteria (ORTAC).

F. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would include, potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment 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. These risks will be mitigated by setting a schedule that aligns with outage availability.

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T-SS-08	FUTURE TRANSMISSION REGIONAL PLANS
Primary Trigger:	Regional Planning
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness, Public Policy Responsiveness, Financial Performance

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	10.7	20.0	20.4	20.4	20.4	91.9

Summary:

This investment is required to enable Hydro One to accommodate future transmission regional plan projects that may be triggered during the regional planning process for which need and scope have yet to be determined.

Regional plans are initiated based on customer needs for load supply capability and reliability. Hydro One is obligated to meet these needs when requested by customers. Not proceeding with this investment is not an option as it would violate Hydro One's Transmission License. This investment is assigned a High Priority to ensure customer future needs are addressed in a timely manner.

A. NEED AND OUTCOME

A.1 INVESTMENT NEED

This investment is required to enable Hydro One to accommodate future transmission regional plan projects that may be triggered during the second cycle of the regional planning process, as documented in SPF Section 1.2. The need for and scope of these projects have yet to be determined.

Regional plans are initiated based on customer needs for load supply capability and reliability. Hydro One is obligated to meet these needs when requested by customers. Not proceeding with this investment is not an option as it would violate Hydro One's Transmission License. This investment is assigned a High Priority to ensure customer future needs are addressed in a timely manner.

B. INVESTMENT DESCRIPTION

This investment covers future local area supply projects anticipated in the test period. These projects' need and scope have not yet been identified at this time. Local area supply projects are identified during regional planning and address issues with supply facilities that connect and deliver power to a group of load stations in an area or region. Each project would be initiated based on a need identified within a Regional Infrastructure Plan.

The scope of these projects may include: new or modified transformation connection facilities, construction of new connection lines and/or stations, and installation of breakers and/or circuit switchers. Each project would be specific to the local area and entail Hydro One constructing one or more of the above listed facilities.

The start of each project depends on obtaining all necessary regulatory and environmental approvals. A System Impact Assessment and Customer Impact Assessment will also be carried out for each project to ensure that there are no adverse impacts to the system or other transmission connected customers.

C. OUTCOMES

C.1 OEB RRF OUTCOMES

This investment will address specific needs for various local areas as identified in the second cycle of the regional planning process.

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - Outcomes Summary

Customer Focus	• Ensure adequate supply capacity for the local area.
Operational Effectiveness	• Comply with Hydro One's obligation under its Transmission License to provide customers with non-discriminatory access.
Public Policy Responsiveness	• Comply with Hydro One's obligation under its Transmission License and the Transmission System Code to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth
Financial Performance	• The investment costs are recoverable through incremental rate revenue from the appropriate rate pool and/or capital contribution from customers.

D. EXPENDITURE PLAN

This investment is non-discretionary. The project costs, as presented in the table below, have been forecasted based on typical costs incurred to complete local supply projects over the past five-year period. The project costs will be recovered from the appropriate rate pool and capital contribution from customer(s), determined on a project-by-project basis in accordance with the Transmission System Code and Hydro One's Transmission Customer Contribution Policy.

The projects' actual in-service costs would be included in the rate base when the projects go into service. For any projects that require "Leave to Construct" approvals, under Section 92 of the Ontario Energy Board Act, the prudence of the proposed expenditures will be tested during the Section 92 process.

Table 2 below summarizes historical and projected spending on the aggregate investment level.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	-	10.7	20.0	20.4	20.4	20.4	-	91.9
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Capital and Minor Fixed Assets	**-**	**10.7**	**20.0**	**20.4**	**20.4**	**20.4**	**-**	**91.9**
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**-**	**10.7**	**20.0**	**20.4**	**20.4**	**20.4**	**-**	**91.9**

E. ALTERNATIVES

This investment will fund projects proposed in response to a specific need identified during the regional planning process; alternatives (if any) will be reviewed as part of this planning process.

F. 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: the outage availability that is required for the work to be executed. These risks 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

Capital Expenditures:

($ Millions)	2023	2024	2025	2026	2027	Total
Net Cost	4.2	4.2	18.7	60.9	54.8	142.8

Summary:

This investment involves constructing the necessary expansion and connection work at terminal networks stations to facilitate the connection of new 230kV double 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. 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 in the near and mid-term as identified by the IESO as part of bulk system planning. 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.

A. NEED AND OUTCOME

A.1 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 near- to mid-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 – in Kingsville and 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",* 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 SS and the Kingsville-Leamington area. At that time, transmission system constraints *east* of Chatham were also identified and that additional assessments were required.

The IESO is currently conducting a bulk planning study for the west of London area targeted for completion in Q3 2021. Preliminary findings indicate that to supply the forecasted electricity demand beyond 2028 and to maintain the capability of the transmission system to deliver the output of generation resources in the Lambton-Sarnia area, the area bulk transmission facilities need to be reinforced. The IESO recommends as the first stage, a new 230 kV, double-circuit transmission line be built between Lambton TS and Chatham SS. As indicated by the IESO, the bulk planning report will also make additional recommendations, around further transmission or resource solutions, as required, to continue meeting bulk system needs into the long-term.

Hydro One received formal direction from the IESO in a hand-off letter on March 26, 2021 to proceed with the development of the new double circuit transmission line from Lambton TS to Chatham SS and associated station expansions to facilitate connection.

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. Not proceeding with this investment would result in Hydro One not meeting its obligation and not addressing the need to provide adequate transmission capacity to supply load growth in the west of Chatham. This investment is assigned a High Priority given the requirement to meet system and customer needs in a timely manner.

B. INVESTMENT DESCRIPTION

The proposed investment involves constructing the necessary expansions at the terminal stations, Lambton Transformer Station (TS) and Chatham Switching Station (SS) for Stage 1 to facilitate the connection of the new 230kV double circuit line 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. As indicated by the IESO, subsequent reinforcement – Stage 2 - will be required to continue to meet bulk system needs into the long-term. Consequently, based on preliminary discussions with the IESO, the proposed investment also anticipates constructing the necessary expansions at the terminals stations, Longwood TS and Chatham TS for Stage 2 to facilitate potential 230kV (or 500kV) lines between London and Chatham. The planned in-service date of the project is Q3 2027 for Stage 1 with Stage 2 following later in Q3 2028.

Hydro One proposes to execute the project in two stages. Stage 1 will address the station work to connect the new double-circuit transmission line from Lambton TS to Chatham SS. Formal hand-off from the IESO has been received on March 26, 2021 to initiate development. Stage 2, whose scope is currently under assessment by the IESO and will be published as part of the bulk planning study in Q3 2021, includes station work to connect a potential new double-circuit transmission line between Longwood TS and Chatham SS.

Stage 1: Station Work – Lambton TS to Chatham SS (Planned In-Service Date: Q3 2027)

- Station expansion at terminal stations, Lambton TS and Chatham SS, including the extension of existing high voltage busses, construction of new diameters and associated high voltage breakers;
- Construction of new protection, control, and telecommunications systems for the new double-circuit transmission line;
- Connection of new circuits into the respective terminal stations.

Stage 2: Station Work – Longwood TS to Chatham SS (Planned In-Service Date: Q3 2028)

- Station expansion at terminal stations, Longwood TS and Chatham SS, including the construction of new high voltage breakers;
- Construction of new protection, control, and telecommunications systems for the new double-circuit transmission line;
- Connection of new circuits into the respective terminal stations;
- Scope of Stage 2 is currently under assessment by the IESO and will be finalized as part of the publication of the west of London bulk planning study in Q3 2021.

The new transmission circuits are expected to be owned by and included in the rate base of a newly licensed partnership(s). These assets will not form part of Hydro One's rate base and, as such, the associated capital expenditures have been excluded from the 2023-2027 forecast.

Hydro One submitted an application to the OEB to establish a Deferral Account for these Affiliate Transmission Projects and the approval for the account is pending (EB-2021-0169). Further information may be found in Exhibit A-03-01.

A map showing the project location is provided below.

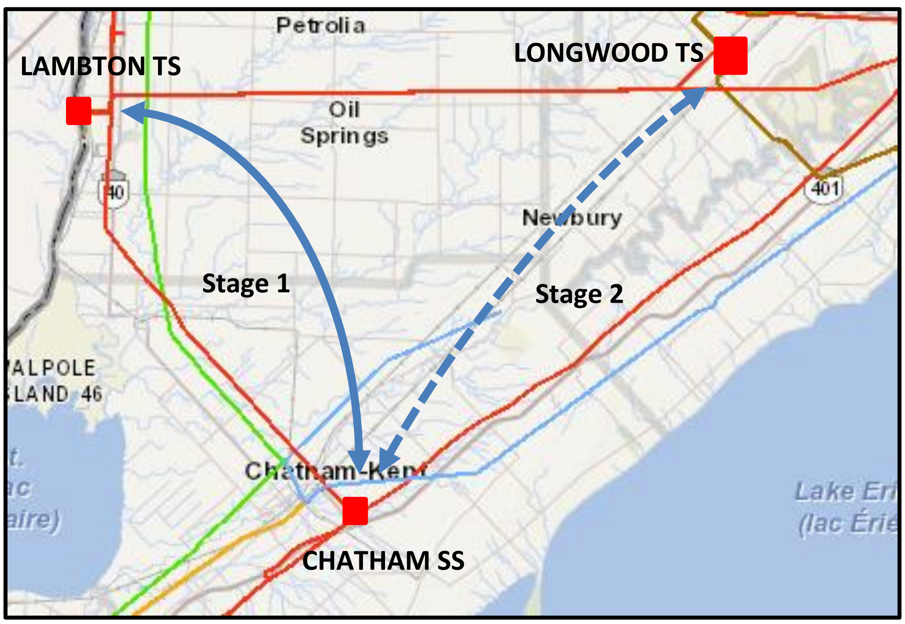

Figure 1: Map Showing Location of the New Facilities

Hydro One plans to initiate work under the Environmental Assessment process for Stage 1, as required under the Environmental Assessment Act, and approvals are expected to be obtained by Q4 2024.

Hydro One will apply for a "Leave to Construct" approval under Section 92 of the Ontario Energy Board Act in Q4 2024. A summary of the need, project description, risk, and costs have been presented herein; with specific details to be provided in the Section 92 application.

The timeline for Environmental Assessment and "Leave to Construct" approval for Stage 2 will be detailed following the release of the IESO's bulk planning study for the west of London area in Q3 2021.

Hydro One studies show that the Stage 1 project will not adversely affect the reliability of the IESO-controlled grid or service to other transmission connected customers. The System Impact Assessment and Customer Impact Assessment will be undertaken to confirm the above prior to the submission of the Section 92 application.

C. OUTCOMES

This investment will provide 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 near- to mid-term and improve the deliverability of resources in the Lambton-Sarnia area for intra-zonal and provincial supply

C.1 OEB RRF OUTCOMES

The following table presents anticipated benefits as a result of the Investment in accordance with the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF):

Table 1 - 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.

D. 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 230kV facilities are network assets and no capital contributions are required from customers.

Table 2 below summarizes historical and projected spending on the aggregate investment level. The "Previous Years" costs are the direct investment costs for investments noted above that have incurred costs prior to the 2023 test year. Likewise, the costs noted in "Forecast 2028+" are investment costs forecast beyond 2028.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2023	2024	2025	2026	2027	Forecast 2028+	Total
Gross Investment Cost	1.0	4.2	4.2	18.7	60.9	54.8	11.2	155.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Minor Fixed Assets	**1.0**	**4.2**	**4.2**	**18.7**	**60.9**	**54.8**	**11.2**	**155.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.0**	**4.2**	**4.2**	**18.7**	**60.9**	**54.8**	**11.2**	**155.0**

E. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

ALTERNATIVE 1: STATUS QUO

This investment is non-discretionary and is needed to ensure supply reliability for the customers in the Windsor-Essex region and support future load growth. The status quo will not satisfy the need for this investment and is therefore not a viable alternative.

ALTERNATIVE 2: CONNECT NEW 230KV TRANSMISSION LINES BETWEEN LAMBTON TS AND CHATHAM SS AND LONGWOOD TS AND CHATHAM SS

Connect the new 230kV double circuit line between Lambton TS and Chatham SS for Stage 1 and between Longwood TS and Chatham SS for Stage 2. This alternative provides higher capacity and maintains system reliability during the construction phase and will meet near and mid-term needs for the region. This alternative will ensure compliance with the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).

F. EXECUTION RISK AND MITIGATION

The risks with respect to the execution of this investment as planned would include, potential delays in securing the Section 92 and environmental assessment approvals. These risks will be mitigated by initiating the Section 92 application process and environmental assessment 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. These risks will be mitigated by setting a schedule that aligns with outage availability.