TORONTO HYDRO®

DISTRIBUTION SYSTEM PLAN

2025 – 2029

SERVICE AREA

18%
of the provincial demand

1,245[1]
employees

37
terminal stations

17,060[1]
primary switches

61,300[1]
distribution transformers

139
in-service municipal substations

15,393[1]
circuit kilometres of overhead wires

13,765[1]
circuit kilometres of underground wires

183,620[1]
poles

4
operation centres

1
control centre

790,000[1]
Total customers

707,178
Residential Service customers
(includes houses, apartments and condominiums)

82,820
General Service customers with monthly peak demand of less than 5,000 kW
(includes schools, restaurants and most shopping malls)

42
Large Users with monthly peak demand of 5,000 kW or greater[2]
(includes hospitals, universities and large manufacturers)

[1] Figures are approximate.

[2] Averaged over a 12-month period.

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A Distribution System Plan Overview

A1 Introduction

Toronto Hydro's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's capital investment plans and supporting information for the 2025-2029 period. The capital programs described and justified in this plan address urgent and necessary work related to the distribution system assets that safely power the City of Toronto, as well as the general plant assets that keep the utility's "24/7" operations running and responsive to customer needs and requests.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving and operating within a dense, mature, and growing major city. In addition, this plan allows Toronto Hydro to meet the demands of a more dynamic environment driven by evolving customer preferences and increases in future customer demand due to an unprecedented energy transition.

Toronto Hydro is on track to successfully complete its previous plan for 2020-2024, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Due to the imposition of a 0.9 percent stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity;

- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition; and
- Staying on track to complete the Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time and within budget.

Despite the progress achieved during the 2020-2024 rate period, investing in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system, while preparing the system to meet the demands of increased electrification, remains a priority for the utility. Extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, evolving energy needs driven by decarbonization efforts, increased electrification, the proliferation of Distributed Energy Resources ("DERs"), the digitalization of the economy, increasing technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand. This is adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.

The 2025-2029 DSP strikes a balance between these system needs and customer preferences, including:

- Price and reliability as top priorities, with reliability becoming increasingly important to residential customers, especially reducing the length of outages during extreme weather events;
- Expectations to invest in new technology to reduce costs and make the system better even if the benefits are not immediate, as long as the costs and benefits are clear; and
- Proactive investment in system capacity to ensure high growth areas do not experience a decrease in service levels.

The resulting five-year capital expenditure plan represents the minimum level of investment needed to confront the many and diverse challenges that the utility faces as a steward of the grid. Through an outcomes-oriented, customer-focused integrated planning process, this plan was designed to achieve balance between price and service quality performance both in the near-and longer-term, while readying the grid with least regrets investments to serve the needs of an increasingly electrified economy.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (2022), and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the guidance in the OEB's Handbook for Utility Rate Applications (2016). In addition to the expenditure plan and forecast information for 2025-2029, the DSP provides historical and bridge year information for 2020-2022 and 2023-2024 respectively, including information on expenditures and accomplishments, material variances, and measured performance during the 2020-2024 plan period. In developing this DSP, Toronto Hydro built upon the experience of its last DSP (covering the 2020-2024 period) and the OEB's findings in the 2020 Custom IR Application, including refining successful elements (e.g. customer engagement, outcomes framework) and making substantial enhancements to certain fundamental elements (e.g. Asset Condition Assessment).

A2 DSP Organization

The 2025-2029 DSP consists of the following five major sections:

- **Section A – Distribution System Plan Overview:** Provides an overview of the key elements of the 2025-2029 DSP, including brief summaries of the 2025-2029 Capital Expenditure Plan and its drivers and outcomes; the Asset Management System including the principles, processes, and methodologies that underpin the plan; and the Customer Engagement results that informed the plan.
- **Section B – Coordinated Planning with Third Parties:** Provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, including information regarding broad regional planning efforts, and consultation with customers and telecommunication entities.
- **Section C – Performance Measurement for Continuous Improvement:** Provides an overview of Toronto Hydro's performance measurement framework and describes Toronto Hydro's historical reliability performance.
- **Section D – Asset Management Process:** Describes Toronto Hydro's asset management system, the current state of the assets and system performance challenges, and the utility's asset lifecycle optimization and risk management practices and methodologies. It also includes details on the utility's strategy to manage system capacity and modernize the grid effectively; as well as its Net Zero 2040 strategy.[1] The processes, tools, and information in this section were used to derive the 2025-2029 Capital Expenditure Plan.
- **Section E – Capital Expenditure Plan:** Describes how Toronto Hydro leveraged various substantive inputs – including Customer Engagement findings – to develop the 2025-2029 Capital Expenditure Plan and its customer-focused objectives. This section also contains detailed justifications and business cases for the 20 capital programs that constitute the plan.[2]

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[1] These strategies are provided in Sections D4, D5, and D7 respectively.

[2] The vintage of asset data used within the DSP is primarily from year end 2022, unless noted otherwise, with the exception of the system peak load forecast, which was as of Oct, 2022.

A2.1 Concordance with the Chapter 5 Filing Requirements

The structure of Toronto Hydro's DSP generally concords with the headings of the OEB's Chapter 5 Filing Requirements. This concordance is summarized in Table 1 below.

Table 1: Concordance between DSP Sections and Chapter 5 Headings

DSP Sections	Filing Requirement Headings
Section A	5.2.1 – Distribution System Plan Overview
Section B	5.2.2 – Coordinated Planning with Third parties
Section C	5.2.3 – Performance Measurement for Continuous Improvement
Section D	5.3 – Asset Management Process
Section E	5.4 – Capital Expenditure Plan

There are minor exceptions to the concordance between Chapter 5 and DSP headings as follows:

- With respect to requirements under section 5.2.3, Toronto Hydro does address reliability-related requirements within section C, but Service Quality Requirements ("SQR"), including OEB Appendix 2-G, are addressed outside the DSP within the utility's overall Historical Performance Results evidence at Exhibit 1B, Tab 3, Schedule 2. Toronto Hydro briefly discusses achievement of objectives for continuous improvement from the 2020-2024 DSP in section C, but provides amore detailed discussion in section E4 and Exhibit 1B, Tab 3, Schedule 2.
- Toronto Hydro addresses transmission or high voltage assets deemed as distribution assets (under section 5.3 of filing requirements) in Exhibit 2A, Tab 1, Schedule 1.
- Although touched on in section D4, the main narrative addressing "System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources" requirements under section 5.3 remains in the Capital Expenditure Plan section of the DSP (Section E3) for continuity with Toronto Hydro's 2020-2024 DSP structure.
- CDM Activities to Address System Needs under 5.3 are discussed at a high-level within section D (e.g. see D3.3.2.3, D4.2, or D5.2.2), and a more comprehensive discussion of these activities (i.e. demand response/flexibility services) and how they were integrated in planning is provided within the Non-Wires Solutions ("NWS") program evidence within the Capital Expenditure Plan (E7.2).

A3 System Challenges and Trends

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2025-2029 forecast period. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate, and utilization please refer to Section D2.

A3.1 Deteriorating and Obsolete Assets

Toronto Hydro owns and operates a mature distribution system. Despite its achievements in renewing the grid and improving reliability over the last decade, defective equipment continues to be a leading contributor to the duration of outages on the grid, representing approximately 40 percent of annual power interruptions experienced by customers based on duration (excluding Loss of Supply and Major Events).[3]

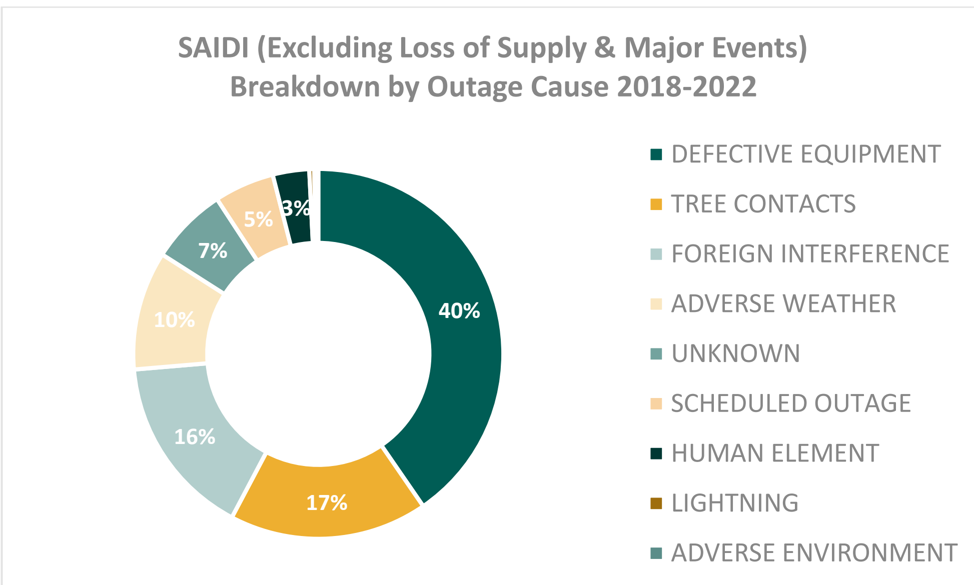

Figure 1: SAIDI (Excluding Loss of Supply & Major Events) Breakdown by Outage Cause 2018-2022

Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. The utility's Asset Condition Assessment ("ACA") demographic results, based on its Condition Based Risk Management ("CBRM") methodology, indicate substantial asset investment needs for a number of critical asset classes over the plan period. For Toronto Hydro's high-volume overhead and underground asset populations, the rate of asset deterioration expected by the end

[3] For more information on Toronto Hydro's historic reliability performance see Exhibit 2B, Section C

of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the rate of deterioration is somewhat lesser for network and stations assets, these smaller asset populations are still exhibiting significant projected deterioration and will require sustained investment to manage failure risks and other obsolescence-related risks (e.g. heightened risk of flood damage).[4]

In addition to asset condition, approximately a quarter of the utility's grid equipment continues to operate past useful life. An additional 11 percent is expected to reach that point by 2030, unless the utility invests in upkeeping system infrastructure in the 2025-2029 period.

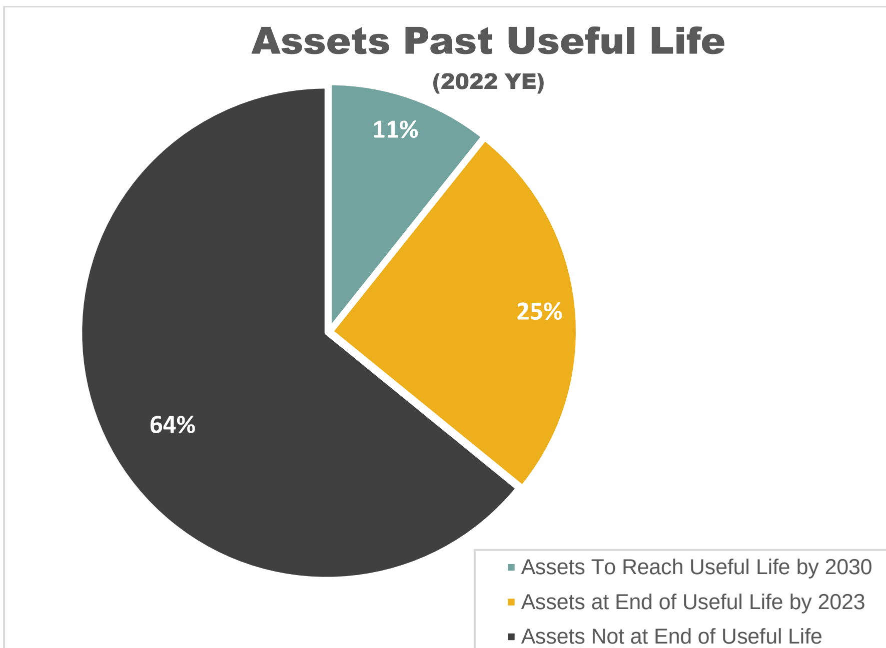

Figure 2: Percentage of Assets Past Useful Life

Allowing the number of assets past useful life, or in deteriorated condition, to grow increases the likelihood of power outages due to equipment failure, puts public and employee safety at risk, and leads to negative environmental outcomes. To manage these risks, Toronto Hydro must regularly inspect equipment to maintain its condition, or replace equipment that is in bad condition or performing poorly, before a failure occurs.[5]

[4] Refer to Exhibit 2B, Section E2.2.1.1 for an overview of asset condition demographics.
[5] Exhibit 2B, Section E2

The utility also continues to face challenges related to higher-risk, obsolete, legacy assets, and asset configurations such as rear lot plant, box construction, non-submersible network equipment, and direct-buried cable. Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often featuring obsolete components with limited or no suppliers or skilled labour to support maintenance, repair, or replacement. Due to asset-specific defects or deficiencies, these assets typically carry elevated reliability, safety, or environmental risks. For example, direct-buried cable and non-submersible network protectors are highly susceptible to moisture-related damage and continue to be significant contributors to reliability and safety risk.

In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro developed a risk-calibrated plan to invest the minimum required to prevent a decline in reliability over the short- and long-term while investing to reduce potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant.

A3.2 Complex Operating Conditions

Toronto Hydro operates in a complex urban environment based on the dense nature of the city's population, the age of the city's infrastructure, and the nature of its customer base. These each pose material challenges in the utility's day-to-day operations.

Toronto is an urban service territory with a population density of 4,428 people per kilometer.[6] Table 2 below compares Toronto's population density with the five largest cities in Ontario:

Table 2: Ontario Cities Population Density[7]

Ontario's 5 Largest Cities by Population	Population (People)	Land Mass (km^2)	Population Density (People/km)
Toronto	2,794,356	631.1	4,428
Ottawa	1,017,449	2788.2	365
Mississauga	717,961	292.74	2,453
Brampton	656,480	265.89	2,469
Hamilton	569,353	1118.31	509

Based on Census Subdivision data from 2021 Census

[6] The City of Toronto is home to approximately three million people within a land mass of 631.1km per Statistics Canada, Canada's Large Urban Centres Continue to Grow and Spread (February 9, 2022) https://www150.statcan.gc.ca/n1/daily-quotidien/220209/dq220209b-eng.htm; Statistics Canada, Defining Canada's Downtown Neighbourhoods: 2016 Boundaries (May 11, 2021)

[7] Statistics Canada, Table 98-10-0002-01 Population and dwelling counts: Canada and census subdivisions (municipalities) https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=9810000201

The density of Toronto Hydro's service territory is unique even within an international context due to the ever-increasing number of high-rise buildings. As seen in Table 3 below, New York City is the only urban centre in the world with more high-rise buildings than Toronto:

Table 3: International Cities High-Rise Buildings[8]

Rank	City	Country	Highrise Buildings
1	New York City	United States	6,223
2	**Toronto**	**Canada**	**2,598**
3	Seoul	South Korea	2,578
4	Dubai	United Arab Emirates	2,360
5	Hong Kong	China	1,916
6	Tokyo	Japan	1,533
7	Busan	South Korea	1,311
8	Kyiv	Ukraine	1,275
9	Chicago	United States	1,247
10	Shanghai	China	1,236

As a dense and old city by North American standards, Toronto also suffers from a challenging combination of legacy standards, limited availably of rights of way for locating distribution equipment, underground congestion which drives a need for increased co-ordination with other utility providers (e.g. water, transit, natural gas, telecommunications), complex permitting and approval processes, longer drive times due to traffic congestion, limitations on the size and scale of distribution assets, and disruptions related to large-scale local events. All of these considerations translate into significant planning and coordination requirements, adding both time and costs to system maintenance, renewal and enhancement investments.[9]

Beyond challenges created by service territory, density and asset vintage, the unique customer base in the downtown core places additional weight on Toronto Hydro's responsibility as a system operator. This customer composition – which includes major hospitals, the provincial legislature, and headquarters of banks, businesses and other critical financial institutions – necessitates elevated requirements for reliability and continuity of service to customers whose operations are critical to

[8] Highrise building categorized as a multi-floor building at least 12 stories or 35m in height. As per data from SkyscraperPage, Global Cities & Buildings Database https://skyscraperpage.com/cities/#notes
[9] Exhibit 1B, Tab 3, Schedule 3

the sound functioning of the provincial and federal economy. As a result, Toronto Hydro's downtown system is designed and operated with a high-level of redundancy, which in turn requires that additional prudent costs be incurred.[10]

A3.3 A Growing City

The population of Toronto is also increasing and expected to grow by approximately 23.8 percent between 2021 and 2031, a marked increase from the 6.8 percent growth over the prior decade (from 2011 to 2021).[11] The growth is concentrated in certain pockets, namely the downtown core and along the transit corridors, and is oriented vertically with a continuing trend of high-rise developments. This has resulted is a marked need for new housing, transit solutions, and infrastructure, all of which needs to be serviced by Toronto Hydro in the years to come.[12]

This growth is underscored by the fact that Toronto has led the North American crane count since 2015 by a margin that is almost equivalent to the rest of the cities combined.[13]

[10] Ibid
[11] City of Toronto, Toronto's Population Health Profile (February 2023) https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf
[12] Exhibit 2B, Section D2
[13] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023 (April 15, 2023) https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

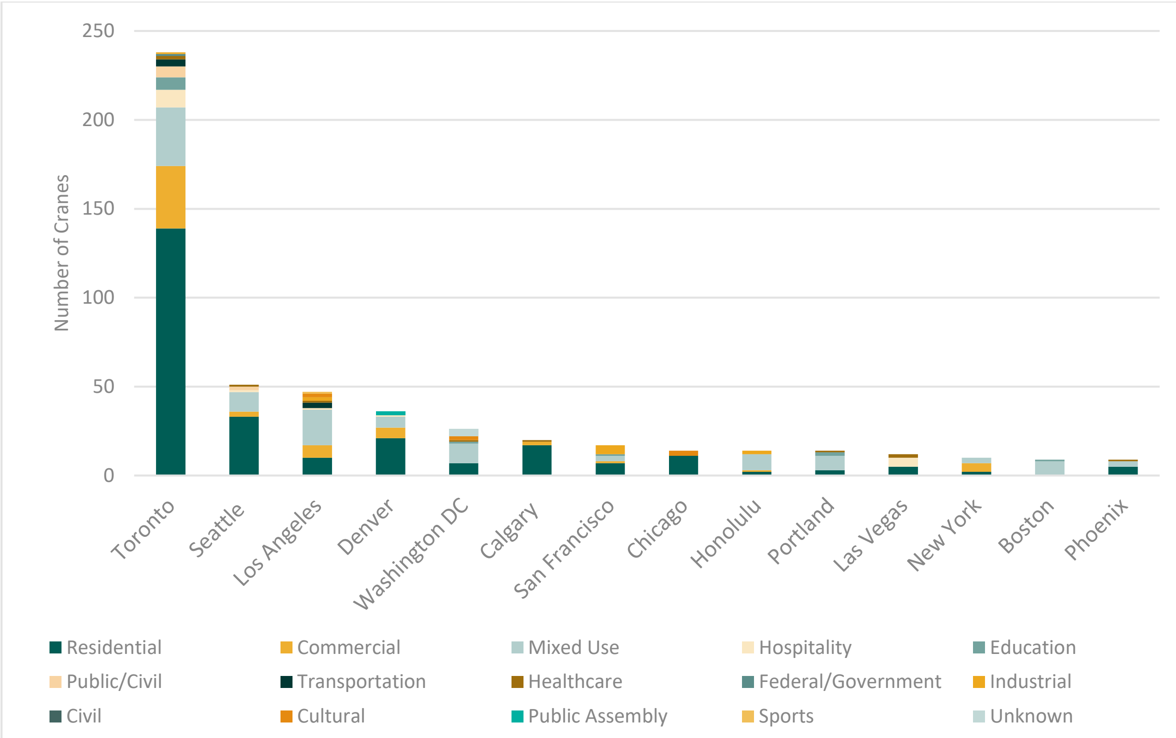

Figure 3: RLB Crane Index - Q1 2023

In addition to high-rise buildings, this growth is also driving the development of new housing communities through the redevelopment of areas such as Downsview, the Golden Mile and the Port Lands, some of which are planned as net zero communities and to meet the highest performance measures of the Toronto Green Standard.[14]

The significant expansion of transit networks is also needed to support this population growth and there are numerous new projects under construction in the city including the Yonge North Subway Extension, Finch West LRT, Scarborough Subway Extension, Eglington Crosstown LRT, Eglinton Crosstown West Extension, and the Ontario Line.[15]

Finally, this growth is also putting additional stress on the system through the incremental loads associated with technology and digitalization. In addition to organic growth, Toronto has become

[14] Exhibit 2B, Section D4
[15] Exhibit 2B, Section E5.2

Canada's largest data center market, with 107 MVA of incremental demand load connected during the 2020-2024 period and 207 MVA forecasted to come online from 2025-2029.[16]

A3.4 Climate Change and Adverse Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 110 times per year as opposed to 87 times per year currently.[17] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Extreme weather amplifies the challenge of distributing electricity to a mature, dense, and rapidly growing urban city. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall can cause major system damage and result in prolonged power outages. As evidenced by recent events outlined in Table 4 below, extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge.

Table 4: Extreme Weather (January 2020 through May 2022)

Event	Description of Impact
High Winds Storm (May 2022)	• 142,052 Customers impacted at its peak • 5 days to restore power to all customers
Flash Storm (August 2021)	• 20,000 customers impacted at peak • 2 days to restore power to impacted customers
Thunderstorm High Volume Event (July 2021)	• A line of thunderstorms with windspeeds in excess of 75 km/h. • 12,000 customers were impacted at its peak • Service restored for the majority of customers within 2 days
High Wind Event (April 2021)	• Wind expected to reach ~95hm/hr • 22,000 customers impacted at its peak • 1 day to restore power to impacted customers

[16] Exhibit 2B, Section E5.1
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

Event	Description of Impact
High Wind Event (November 2020)	• Winds in excess of 100 km/h • Estimated 8000 customers impacted and 101 outages at its peak
Flash Storm (July 2020)	• Approximately 50-70mm of rain • 50,000 customers impacted at peak • Impacted customers restored within 2 days
Adverse Weather (January 2020)	• Approximately 60mm of rain, 5-15mm of ice and 90 km/h winds • 4900 customers impacted at its peak • Impacted customers restored within 3 days

Adverse weather affects the distribution system in different ways. The underground system is vulnerable to flooding from extreme rainfall, while the overhead system is susceptible to extreme winds, freezing rain, and wet snow, resulting in damage and outages. Broken trees and the weight of ice and snow accretions can bring lines, poles, and associated equipment to the ground. For instance, in May 2022, an extreme wind event known as the Derecho Storm struck Southern Ontario and Quebec with 120+km/h winds. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment leaving approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) without power at the peak of the storm. While the majority of customers were restored within 48 hours, it took approximately 5 days and cost approximately $2.35 million to restore power to all customers.[18]

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Weather conditions of high heat, high winds, heavy rainfall, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 4 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 25 years. In both cases it is observed that there is an increasing trendline over the period. With respect to high wind days, an even steeper increase has been observed, and seven

[18] Exhibit 2B, Section D2

of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

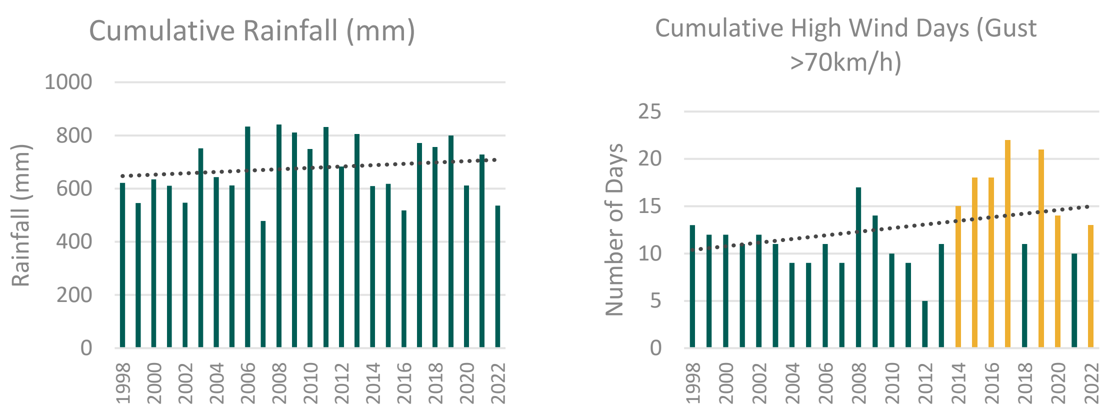

Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[19]

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[20]

These weather trends have increased reliability risks for the distribution system. Toronto Hydro analyzed system reliability data to understand the correlation between wind speed above 70 kilometres per hour, the number of forced outages on the overhead system, and SAIDI performance. This revealed a high correlation between wind speed above 70 kilometres per hour and the number of forced outages on the overhead system. It was also determined that higher wind speeds were correlated with increased SAIDI.

Toronto Hydro has recognized that existing codes, standards, and regulations with regard to historical weather data do not always account for ongoing and future changes to climate. To address this, Toronto Hydro now incorporates climate data projections into its equipment specifications and station load forecasting. In 2016, Toronto Hydro updated its major equipment specifications to adapt

[19] Government of Canada, Weather, Climate and Hazard Historical Data, http://climate.weather.gc.ca/historical_data/search_historic_data_e.html
Weather data compiled using Toronto Lester B. Pearson INTL A for January 1998 to June 2013 and Toronto INTL A for July 2013 to December 2022.
[20] *Supra* note 16.

to climate change, such as using stainless steel construction for submersible transformers and replacing air-vented, padmounted switches with more robust designs. As part of the ongoing efforts, Toronto Hydro has planned various activities between 2025 and 2029, including reconfiguring feeders and relocating assets away from the ravines in the Overhead System Renewal program, replacing submersible transformers, and implementing flood mitigation systems at vulnerable stations.

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

A3.5 Technology Advancement

Technology and innovation are also driving the need for a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed. The role of the utility continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources (DER), such as electric vehicles, solar panels, and battery energy storage systems.

Customers are showing a continued interest in participating in the electricity system as both consumers and producers of power. DER connections have grown in recent years as result of government policies and declining costs of technologies such as solar panels. By the end of the decade, Toronto Hydro expects to have over 4,400 DER connection projects representing a total installed capacity of approximately 517 MW, an increase of approximately 67 percent compared to 2022.[21]

Integrating DERs into the grid provides customers more tools to actively manage their energy needs, and enables the grid to be supplied by locally-generated renewable electricity resources. To advance these outcomes, Toronto Hydro must address the significant challenge of accommodating electrons that flow bi-directionally within a grid that was not built for this type of supply and demand. Equipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users. Toronto Hydro

[21] Exhibit 2B, Section E5.1

monitors all DER connections closely for these factors to ensure that the grid remains safe and reliable for all customers, and is building advanced grid capabilities to mitigate against these risks and enable efficient DER adoption by customers in the future.[22]

Technological advancement also poses the challenge of managing a heightened risk of digital security threats, as cyber-crime intensifies across Canada due to changing geopolitical dynamics. While smart grid systems, infrastructure automation, and other technological advancements being used by the utility and its customers offer many benefits, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This intensifying global challenge is particularly acute in major economic centers such as Toronto. Electric utilities are targets for security breaches because of the critical role they play in enabling essential service providers (e.g. hospitals, public transit, water treatment systems, communications, and traffic management) and the databases of confidential customer information they possess.[23]

Toronto Hydro needs to prepare itself to assist customers in taking advantage of technological innovation and advancements, while also protecting itself and its customers from the risks they introduce.

[22] Exhibit 2B, Section A
[23] Exhibit 2B, Section D8; Exhibit 2B, Section E8.4

A4 Development of the 2025-2029 DSP

A4.1 Business Planning & Customer Engagement

In developing a multi-year investment plan, Toronto Hydro begins from the principle that the utility is entrusted by customers and stakeholders to prepare a responsible plan that balances both price and service quality outcomes. The 2025-2029 Plan achieved that balance through an integrated and iterative business planning process that considered customer feedback from start to finish.

Toronto Hydro's 2025-2029 DSP, including the 2025-2029 Capital Expenditure Plan, was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management system ("AMS") and other operational planning activities, discussed in detail in Section D of the DSP. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 5, below.

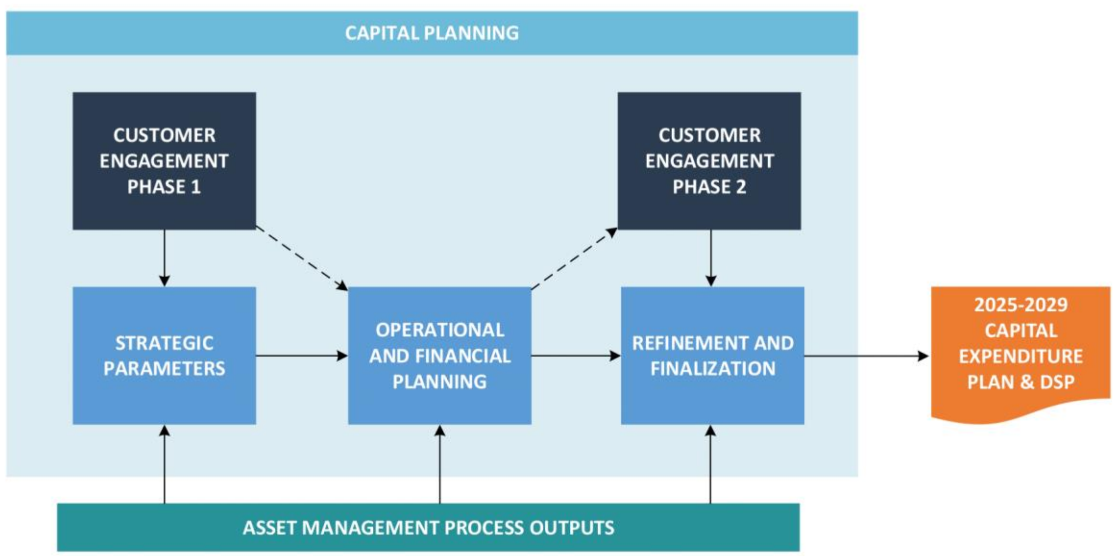

Figure 5: Capital Planning in Business Planning

Toronto Hydro began planning by engaging customers to ascertain their needs and priorities for the 2025-2029 planning period (i.e. Phase 1 of Customer Engagement), and used the customer feedback received to provide strategic direction to the planning process.

The common themes of customer priorities centered around the following:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customer are more sensitive to power interruptions and prioritize reducing the total number outages.
2. **New Technology:** Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better, even if the benefits aren't immediate, as along as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero—and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

With consideration for customers' needs, priorities and other inputs, Toronto Hydro organized its plan around the following investment priorities.

1) **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
2) **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
3) **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
4) **General Plant:** Investments in vehicles, work centers and information technology ("IT") infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For each of these strategic priorities, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

1 **Table 5: 2025-2029 Performance Objectives**

Investment Priority	Key Performance Objectives
Sustainment and Stewardship	• Maintain recent historical system reliability • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Adhere to previous commitments for safety and environmental compliance activities (e.g. removal of at-risk PCBs by 2025; complete Box Conversion by 2026) • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools. • Ensure investment pacing contributes to stable long-term investment requirements for all assets (2030+)
Modernization	• Prioritize investments that will deliver demonstrable benefits to customers, especially enhancements that will improve value-for-money in the long-term (i.e. efficiency) • Improve system reliability through enhanced fault management, leveraging automation and advanced metering through Advanced Metering Infrastructure (“AMI”) 2.0 • Enhance system observability across the system, enabling better asset management and operational decision making • Leverage technology to improve customer experience (e.g. reliability, power quality, customer tools, DER integration) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown
Growth & City Electrification	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment) • Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections • Install control and monitoring capabilities for all generators > 50kW • Accommodate relocations for committed third-party developments, including priority transit projects

Investment Priority	Key Performance Objectives
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code,[24] *Occupational Health and Safety Act,*[25] CSF, etc.) • Achieve emissions reduction by implementing Toronto Hydro's NZ40 strategy • Support modernization objectives including grid automation and customer experience. • Minimize cybersecurity risks associated with IT/OT infrastructure • Ensure IT infrastructure is available and reliable with minimal service disruption

To ensure that price was kept top-of-mind, the utility also adopted top-down financial constraints for the development of the plan:

1. **Price Limit:** Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges.[26]
2. **Budget Limits**: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period.

In developing these strategic parameters, Toronto Hydro considered a number of inputs including but not limited to:[27]

- customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- historical and forecast system health demographics and performance;
- long term asset stewardship needs;
- forecasted system use profiles and pressures;
- safety and environmental risks; etc.

Based on the aforementioned inputs, through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price

[24] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[25] *Occupational Health and Safety Act,* RSO 1990, c. O.1
[26] As calculated for the monthly bill of a Residential customer using 750 kWh.
[27] For a more exhaustive list, please refer to Exhibit 2B, Section E2.1.1.

impacts for customers, as informed by the feedback in Phase 1. Toronto Hydro selected the $4,000 million capital budget limit to achieve this balance of keeping rates reasonable without compromising performance.

These parameters guided the operational and financial planning activities that produced the Capital Expenditure Plan for 2025-2029. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with its short- and long-term performance objectives, while remaining within the financial constraints established for the 2025-2029 period. This exercise led to a $480 million reduction between the initial plan proposals and the draft plan, as described in Section E2.

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on (i) pacing and bill impacts for key investments areas in Toronto Hydro's plan; and (ii) the price of the overall draft plan and whether customers are willing to accept it. Overall, a majority (84 percent) of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[28] The program outcomes in Sections E5 through E8, as well as the 2025-2029 Performance Outcomes for the plan as whole (discussed in Exhibit 1B, Tab 3, Schedule 1 and Exhibit 2B, Section E2 respectively), have been developed and calibrated to reflect customer feedback, ensuring the performance and accomplishments of the DSP are tracked over the 2025-2029 period in relation to outcomes that are meaningful to customers.

These investment priorities are driven by critical needs that, if not adequately addressed, could impair Toronto Hydro's ability to deliver the outcomes that customers value. In some cases, these risks will materialize in the near term, such as lack of capacity to support urban intensification and economic development. However, in many cases, the risks will materialize in the medium to long term as the grid becomes more heavily-utilized and more susceptible to longer and more frequent outages that are complex and costly to resolve. Toronto Hydro must invest in the priorities described below to manage these risks.

[28] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

A4.2 Asset Management Process and Enhancements

Toronto Hydro's distribution system AM Process is explained in detail in Section D and is generally aligned with the AM Process described in the 2020-2024 DSP, with some enhancements as discussed below. The objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders, while meeting all of the utility's mandated service and compliance obligations. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

Toronto Hydro is continually monitoring and improving AM decision-support systems, enterprise systems and various inputs that support effective asset management. Recent Improvements to Toronto Hydro's AMS over the 2020-2024 period are highlighted in Figure 6 below. For more information on these improvements, please refer to Section D of the DSP.

As highlighted in Figure 6 and Section D1.3, Toronto Hydro has an extensive track record of continuous improvement in asset management. Looking ahead, the utility recognizes that the coming acceleration in decarbonization, digitalization (e.g. automation), and decentralization (i.e. two-way energy flows) within the energy economy will result in much greater asset management complexity and a more urgent need for adaptive flexibility within the utility's management systems. The utility believes that success in this more complex environment will depend in large part on having a strong management foundation in the form of a rigorous and comprehensive AMS that consistently tracks toward industry best practices.

With this context in mind, Toronto Hydro is committing to aligning its AMS to the ISO 55001 standard for asset management, with the goal of achieving certification within the 2025-2029 rate period. ISO 55001 was developed by the International Organization for Standardization and is the most recognized standard for asset management globally. It provides terminology, requirements and guidance for establishing, implementing, maintaining and improving an effective asset management system, and represents a global consensus on asset management and how it can increase the value generated by organizations like Toronto Hydro.

Fundamental to the ISO 55001 framework are the concepts of strategic alignment, risk-based decision-making and continuous improvement. By pursuing certification, Toronto Hydro is volunteering to be held accountable through independent audits for the continuous improvement of its AMS and the maturation of its risk-based decision-making frameworks. The utility believes that the effort of pursuing certification will provide the additional rigor and discipline required to deliver greater value and performance, including greater cost-efficiency, as customer and stakeholder needs rapidly evolve and operating challenges become more intense (e.g. climate risk).

To streamline Toronto Hydro's asset management process, the utility is also embarking on a transformative project to implement an Engineering Asset Investment Planning ("EAIP") solution to support investment planning and project development activities. This strategic initiative is poised to elevate Toronto Hydro's annual project portfolio and long-term asset investment strategies, while simultaneously revitalizing asset management methodologies and simplifying the scope formulation procedures. As part of its multi-year efforts to adopt the EAIP solution, Toronto Hydro is developing a custom and robust value framework to evaluate relative value of its investments, leading to more well-informed and strategic asset management decisions as discussed in Section D3 of the DSP.

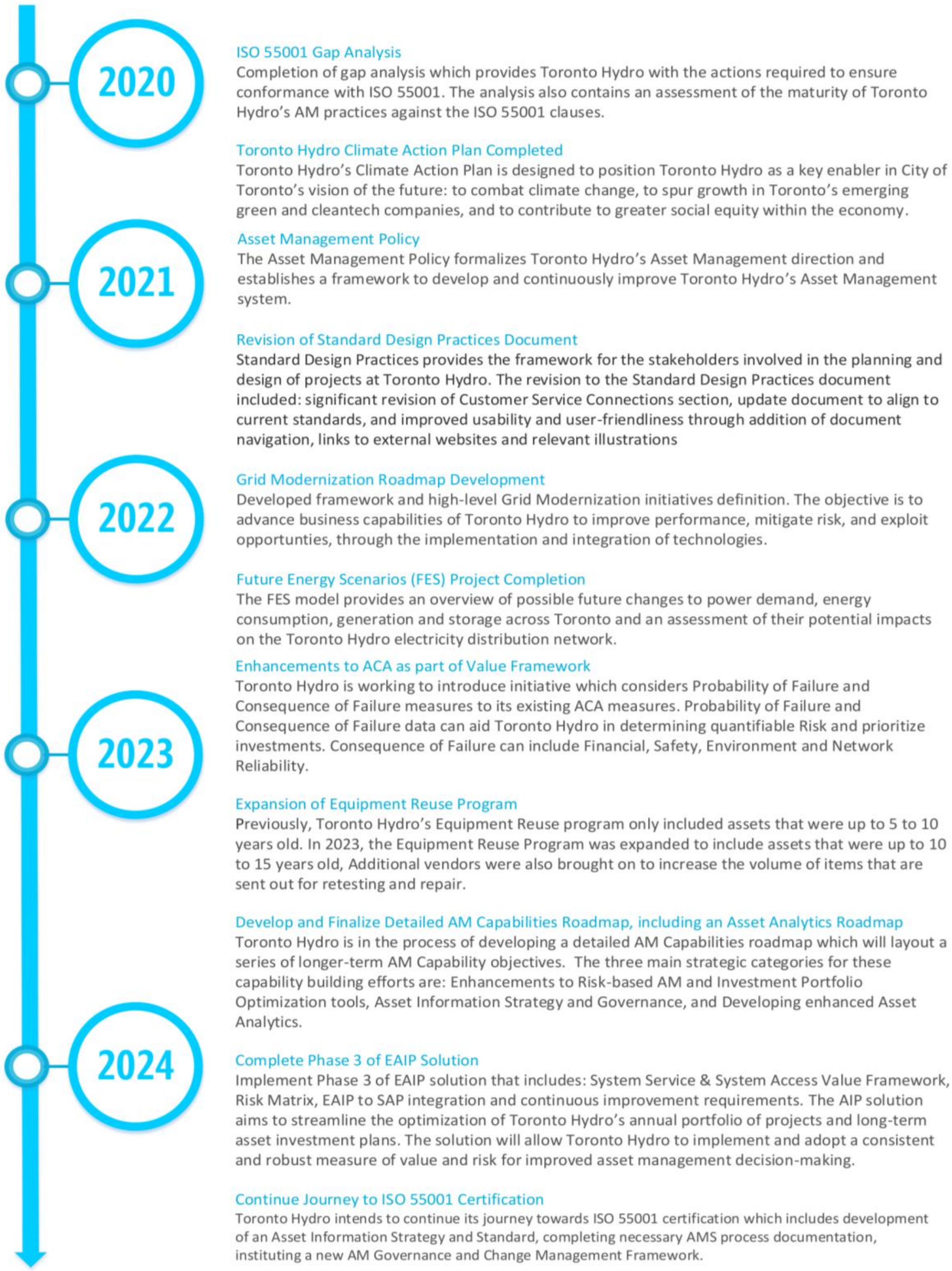

Figure 6: Recent Enhancements of the AM Process (2020-2024)

In addition to the distribution system AMS, Toronto Hydro has similarly robust AM processes for its facilities, fleet, and IT assets. The AM approach for facilities and IT are summarized in Sections D6 to D8, while the AM strategy for fleet can found in the Fleet and Equipment Services program in Section E8.3.

A5 Investment Priorities

A5.1 Sustainment & Stewardship

Sustainment investments to renew aging and deteriorating infrastructure and standardize outdated equipment continue to be the largest part of the 2025-2029 Investment Plan. These investments must be made to maintain system performance, mitigate reliability, safety, and environmental risks, and enhance the grid's capability to serve electrified technologies such as electric vehicles, solar panels, energy storage batteries, and electric heat pumps and boilers.

Past investments in the grid and operations have resulted in improvements in reliability, safety and environmental outcomes – the average duration of outages customers experience now compared to a decade ago was reduced by 26 percent over the last decade, the injury rate for employees has decreased by 60 percent, oil spills have been avoided, and the utility is on track to eliminate at risk PCB transformer from its system by 2025.[29,30] Investing in the performance and long-term stewardship of an aging, deteriorated, and more highly-utilized system remains an urgent priority for the utility, alongside getting the grid ready to serve Toronto's growing electricity needs.

System health is a leading indicator of a safe and reliable grid. Allowing system health metrics – age and condition – to deteriorate would lead to the gradual but steady degradation of system performance. As an example, underground cables are the largest contributor to defective equipment outages and continue to present significant demographic challenges in the coming years with approximately 73 percent of direct buried cables in the horseshoe area expected to be past their serviceable life by the end 2022.[31] Proactive investment in the replacement of these assets is a key part of sustaining the short and long-term performance of the grid.

[29] Exhibit 1B, Tab 3, Schedule 2
[30] Exhibit 4, Tab 4, Schedule 1
[31] Exhibit 2B, Section E6.2

Recognizing that customers are generally satisfied with current levels of reliability, and expect the utility to invest in new technology for the future,[32] Toronto Hydro right-sized the sustainment objectives of the Investment Plan to maintain (rather than improve) the overall health of the grid over the 2025-2029 period. Maintaining system health metrics is necessary to sustain grid performance and prevent the accumulation of a backlog of equipment at risk of failure, or otherwise needing to be upgraded. Renewal investment backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as high-inefficiencies in work execution. Such inefficiencies stem in part from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through paced proactive investment.[33]

Keeping pace on renewal is also important for hardening the grid against more frequent extreme weather events, and standardizing outdated equipment that poses barriers to electrification. For example, legacy 4 kilovolt stations and feeder equipment, restricts the connection of large electrified loads and distributed energy resources. To prepare the grid for electrification these assets must be gradually converted to new standards, and that work is being done in a paced way through sustainment investments that also deliver safety, reliability and environmental outcomes.[34]

Table 6 below provides a summary of Toronto Hydro's sustainment capital programs:

Table 6: Sustainment Capital Programs

Capital Program/Segment	Investment ($ Millions)
Area Conversions[35]	**$237**
Underground Renewal – Horseshoe[36]	**$476**
Underground Renewal – Downtown[37]	**$165**
Network System Renewal[38]	**$123**

[32] Exhibit 1B, Tab 5, Schedule 1, Appendix A
[33] Exhibit 2B, Section E2
[34] *Ibid.*
[35] Exhibit 2B, Section E6.1
[36] Exhibit 2B, Section E6.2
[37] Exhibit 2B, Section E6.3
[38] Exhibit 2B, Section E6.4

Capital Program/Segment	Investment ($ Millions)
Overhead Renewal[39]	**$273**
Stations Renewal[40]	**$218**
Reactive and Corrective Capital[41]	**$328**
Sustainment Capital	**$1,820**

A5.2 Growth and City Electrification

The obligation to serve customers who want to connect to the grid is at the heart of Toronto Hydro's mandate as an electricity distributor. What accompanies that core obligation is the responsibility to make reasonable investments to prepare for future growth. This responsibility is more important than ever, as customers, communities and governments at all levels are actively embarking on an unprecedented transformation of the energy system to mitigate the worst impacts of climate change.

It is clear from studies that have been done locally, provincially, and internationally that decarbonization-through-electrification imperatives are expected to drive demand for electricity in the next two decades. Experts indicate that demand could increase up to 2 to 3 times depending on the range of technologies and policy tools that are adopted.[42]

The particular drivers of demand are subject to dynamic forces of technological advancement, public policy imperatives and consumer behaviour. As an example, the decarbonization of existing housing

[39] Exhibit 2B, Section E6.5
[40] Exhibit 2B, Section E6.6 – includes HONI Switchgear renewal costs of $29M.
[41] Exhibit 2B, Section E6.7
[42] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), while Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf), Eversource (https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of its future energy scenarios (https://www.nationalgrideso.com/document/283101/download).

and industrial buildings remains a policy puzzle, and a number of options are being considered to find suitable paths.[43] To manage this uncertainty and the cost-consequences for customers, the utility must be measured-but-proactive in its investment plan (as both asset and human capital investments are long lead-time), and must be deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in all scenarios.

As outlined above, Toronto Hydro has embraced this uncertainty by prioritizing investments that can provide value under all scenarios under the "least regrets" approach. This enables the utility to meet emerging challenges without having to wait for all unknown variables to stabilize. Based on its least regrets investment philosophy, the 2025-2029 Investment Plan accommodates an increase of 23 percent in system peak demand, which includes electrification of transportation (EVs) across residential, industrial and commercial sectors, as well as major transit projects like the Ontario Line and Scarborough Subway Extension, and redevelopment plans for the Downsview, The Port Lands and Green Mile communities.[44]

The 2025-2029 Investment Plan anticipates a material increase to the customer connection portfolio (consistent with the trend observed in recent years) and expands stations capacity to alleviate future load constraints due to growth resulting from EV uptake, digitalization of the economy (e.g. data centers and digital transformations of existing sectors), and city growth and redevelopment (e.g. urban densification and transit expansion). The 2025-2029 Investment Plan also optimizes near-term system capacity through active management measures such as load transfers and balancing, equipment upgrades, and the targeted use of non-wires solutions – both demand-side measures that leverage customer DERs as well as grid-side technologies such as renewable enabling energy storage systems.[45]

By the end of this decade, DER capacity is expected to increase by approximately 67 percent.[46] Getting these resources safely connected to the grid is necessary to enable greater choice and support customers in achieving their electrification objectives (e.g. ESG, net zero, environmental conscientiousness, home/business resiliency). Moreover, integrating these resources into the system is critical to right-sizing system expansion investments, and developing a grid that is more

[43] City of Toronto, Net Zero Existing Buildings Strategy https://www.toronto.ca/wp-content/uploads/2021/10/907c-Net-Zero-Existing-Buildings-Strategy-2021.pdf
[44] Exhibit 2B, Section D4
[45] Exhibit 2B, Section D4
[46] Exhibit 2B, Section E5.1

resilient in the future as a result of greater levels of local power supply. To accommodate increasing volumes of connections in this area, the 2025-2029 Investment Plan ensures control and monitoring capabilities for all distributed generation and addresses constraints on restricted feeders through traditional investments such as station bus-ties and alternative technologies such as energy storage.[47]

While there is certainty that fundamental change is ahead, there are still degrees of uncertainty about how that change will unfold. For example, government incentives or market evolution could further accelerate customer adoption of electric vehicles or other fuel switching technologies. Similarly, provincial procurement programs could create expanded role for DERs in the deployment of coordinated infrastructure solutions to meet Ontario's energy needs.[48] As a result of such external factors, the pacing and level of certain demand-driven expenditures and revenues can change and materially deviate from the forecast. To that end, Toronto Hydro proposes a flexibility mechanism (known as a variance account) to reconcile differences between forecasted and actual demand-driven costs and revenues. During a time of unprecedented change and transformation in the economy and energy system, it is key to protect both ratepayers and the utility from structural unknowns that could have a material impact on the plan.[49]

Table 7 below outlines the programs that enable growth and city electrification:

Table 7: City Growth and Electrification Capital Programs

Capital Program	Investment ($ Millions)
Customer Connections[50]	$476
Externally Initiated Plant Relocations & Expansions[51]	$76
Load Demand[52]	$236
Generation Protection, Monitoring, and Control[53]	$35
Non-Wires Solutions[54]	$23

[47] Exhibit 2B, Section D4
[48] Exhibit 2B, Section D4
[49] Exhibit 1B, Tab 4, Schedule 1
[50] Exhibit 2B, Section E5.1
[51] Exhibit 2B, Section E5.2
[52] Exhibit 2B, Section E5.3
[53] Exhibit 2B, Section E5.5
[54] Exhibit 2B, Section E7.2

Capital Program	Investment ($ Millions)
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$1,020**

A5.3 Grid Modernization

Toronto Hydro's grid modernization strategy focuses on accelerating the deployment pace of digital field and operational technologies that can deliver future benefits to customers. These benefits include better outage restoration capabilities to improve grid reliability and resilience, and enhanced operational flexibility to manage a more heavily utilized system with increasing bi-directional power flows. Grid modernization investments, once fully implemented and integrated in the next decade, are expected to yield a material step-change improvement in reliability and operational efficiency, to help offset the added reliability and cost pressures associated with electrification.[55]

The modernization plan lays the groundwork for grid automation (commonly known as the self-healing grid) in the horseshoe area of the system starting in 2030 to provide the enhanced levels of reliability and resilience that customers will expect as they electrify their homes and business at a lower cost compared to traditional alternatives. To improve resiliency against major disruptions (e.g. extreme weather; loss of supply) for vulnerable parts of the system, the modernization plan also includes investment in: (a) the targeted undergrounding of equipment to harden vulnerable areas of the overhead system against more frequent and extreme weather events, and (b) enhanced configuration options for the downtown network which serves critical loads such as major hospitals and financial institutions.

Toronto Hydro's journey towards an intelligent self-healing grid is being implemented through an Advanced Distribution Management System ("ADMS"), a multi-faceted software platform with advanced capabilities and connected applications that integrate analytics, real-time data and control algorithms to optimize distribution network operation. The system provides a holistic view of the grid and encompasses advanced applications such as Outage Management System ("OMS"), Fault Location Isolation and Service Restoration ("FLISR"), Volt/Var Optimization, which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient

[55] Exhibit 2B, Section D5

management of DERs by optimizing voltage levels and reactive power flows throughout the distribution system.[56]

Through operational technology such as sensors and switches and software, Toronto Hydro can better monitor, predict, and control the flow of electricity across the system. These capabilities enable the utility to reduce the number and length of outages customers experience, and also pave the way for a more interactive, bi-directional grid that enables customers to choose various technologies to produce, store and sell power back to the grid.[57] In addition, Toronto Hydro plans to invest in overhead and underground line sensors and other condition monitoring and control equipment that provide the utility real-time information about critical assets in the field, and enable more cost-effective system planning and operational decisions.[58]

Modernization investments also create a foundation for the kinds of advanced, real-time and predictive analysis that would be fundamental to Toronto Hydro's evolution toward Distribution System Operator ("DSO") model, if and when such a model is either imposed or offered to distributors in an effort to further enable energy transition outcomes. In such a model, Toronto Hydro would be expected to safely and reliably coordinate, dispatch, and optimize thousands of behind-the-meter generators and flexible loads in order to help maximize the value created by the local energy system for customer, including maximizing the penetration and utilization of non-emitting energy sources. While the policy environment surrounding the role of DERs in the energy transition remains unsettled, the grid modernization capabilities advanced by the 2025-2029 Investment Plan create the foundation for this possible future while also delivering many other tangible benefits to customers irrespective of the DSO policy framework.[59]

Table 8 below outlines Toronto Hydro's modernization capital programs:

Table 8: Modernization Capital Programs

Capital Program/Segment	Investment ($M)
System Enhancement[60]	$151

[56] Exhibit 2B, Section E8.4, Appendix A
[57] Exhibit 2B, Section D5
[58] Exhibit 2B, Section E7.1
[59] Exhibit 2B, Section D5
[60] Exhibit 2B, Section E7.1

Capital Program/Segment	Investment ($M)
Network Condition Monitoring and Control[61]	$6
Metering[62]	$248
Overhead Resiliency[63]	$86
Stations Control and Monitoring[64]	$65
IT Cyber Security & Software Enhancements[65]	$95
Modernization Capital	**$651**

In addition, to the modernization capital investments summarized above, Toronto Hydro proposed to establish a $16 million 2025-2029 Innovation Fund to support the design and execution of pilot projects focused testing of innovative technologies, advanced capabilities, and alternative strategies that enable electrification grid readiness and facilitate DER integration. The Innovation Fund supports utility investment in innovation work that is more early stage, exploratory and developmental in nature, where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of transformation in the energy sector.[66]

A5.4 General Plant

Toronto Hydro needs to maintain facilities, fleet and information technology ("IT") assets and infrastructure to enable efficient business operations. To get maximum value of its work centers, stations buildings, physical security systems, and fleet, the utility monitors and manages asset age and condition with a view to optimizing total lifecycle costs.

[61] Exhibit 2B, Section E7.3
[62] Exhibit 2B, Section E5.4
[63] Exhibit 2B, Section E6.5
[64] Exhibit 2B, Section E6.6
[65] Exhibit 2B, Section E8.4
[66] Exhibit 1B, Tab 4, Schedule 2

In addition to four work centers that provide the necessary conditions for employees to work effectively, Toronto Hydro manages a broad portfolio of approximately 185 stations which house and protect critical equipment such as cables and transformers. Like electrical equipment, facilities assets that are in poor condition pose an increased risk of failure putting key outcomes such as safety, reliability, customer service and productivity at risk. For example, if a station building has a leaking roof or foundation that allows water to infiltrate, there could be permanent damage to distribution equipment leading to lengthy and costly power interruptions and posing hazards to workers and the public.[67]

Investments in the renewal and maintenance of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner. In addition to these table stakes, Toronto Hydro must also address emerging needs to provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather. The utility plans to address these needs through targeted investments in renewing stations buildings and work centres (e.g. exterior cladding, windows, and roofs where critical equipment is housed), and physical security systems (e.g. network-based cameras and access card readers).

Toronto Hydro crews also need safe and reliable vehicles to execute a wide-range of system capital and operations and maintenance work programs. Toronto Hydro's fleet investments include heavy duty and light duty vehicles and equipment (e.g. forklifts and trailers). These vehicles transport employees and materials to and from job sites, perform distribution work onsite, and serve as working space for field employees. Fleet vehicles must be available to support these operations in a safe and efficient manner. Toronto Hydro's fleet investments aim to optimize vehicle operating costs, minimize fleet downtime due to repairs, increase vehicle efficiency and safety, and importantly reduce emissions.[68]

Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to mitigate the impacts of climate change and reach "net zero" by 2040. The utility intends to reduce the emissions produced by its fleet by gradually increasing the complement of electric and hybrid vehicles. Similarly, Toronto Hydro has a paced plan to reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy

[67] Exhibit 2B, Section E8.2
[68] Exhibit 2B, Section E8.3

efficiency measures and fuel switching projects to replace natural gas fueled heaters with electric heating systems.[69]

Finally, General Plant includes investments in information and operational technology ("IT/OT") assets that support a number of business applications and systems which are essential to conducting day-to-day operations such as managing field crews, responding to outages and enabling customer self-serve tools. When these systems are not available, customers service levels decrease, power outages and operational disruptions take longer to fix, and safety of the public and employees is put at risk. Toronto Hydro must invest in upkeeping its IT/OT assets highly reliable and available for conducting critical operations.[70]

Table 9 below outlines Toronto Hydro's general plant capital programs:

Table 9: General Plant Capital Programs

Capital Program/Segment	Investment ($M)
Enterprise Data Centre (Exhibit 2B, Section E8.1)	$72
Facilities Management and Security (Exhibit 2B, Section E8.2)	$145
Fleet and Equipment Services (Exhibit 2B, Section E8.3)	$44
Information and Operational Technology (Exhibit 2B, Section E8.4)	$206
General Plant Capital	**$467**

A5.5 Expected Sources of Cost Savings during the Plan Period

Throughout the plan period, and in the course of executing its DSP, Toronto Hydro will continue to evaluate its operational efficiencies and seek ways to reduce and avoid costs, while increasing value for ratepayers. Toronto Hydro's Productivity evidence at Exhibit 1B, Tab 3, Schedule 3, describes a number of specific productivity initiatives with cost savings and/or other qualitative benefits. The capital program narratives in Sections E5 through E8, and the OM&A narratives in Exhibit 4, Tab 2,

[69] Exhibit 2B, Section D7
[70] Exhibit 2B, Section E8.4

provide several examples of the investments and initiatives that will support the utility's efforts to control costs and increase productivity. The following list highlights some of these activities.

- **Grid Modernization:** Many of Toronto Hydro's planned investments in the 2025-2029 period will support the ongoing modernization of the grid, through the introduction of technologies that support remote monitoring, sensing, protection, and control. A key example of this is the System Enhancement program (Section E7.1). Like all of the capital programs that introduce remote switching and monitoring capabilities, this program is expected to improve the productivity of field employees and system controllers when operating the system and responding to outages (for example, by allowing system controllers to perform switching operations remotely instead of relying on field crews for manual switching). In addition, Toronto Hydro anticipates cost savings related to network system maintenance due to the Network Condition Monitoring and Control program (Section E7.3), as the need for inspections will be reduced by the ability to monitor network vault condition remotely. The modernization of the network will also support more cost-effective customer connections by providing real-time load monitoring that will allow the utility to lift some of the connection capacity limitations on existing secondary networks. Further information on grid modernization benefits can be found throughout all investment categories, and summarized within Toronto Hydro's Grid Modernization Narrative (Section D5).

- **Capacity Improvements:** Capacity improvements from the utility's Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs are expected to allow for more flexibility in scheduling planned outages for maintenance at the affected stations and for the delivery of Toronto Hydro's capital plans generally.

- **Standardization:** By eliminating obsolete asset types across the system through programs such as Area Conversions (Section E6.1), Underground Renewal – Downtown (Section E6.3), and Stations Renewal (Section E6.6), Toronto Hydro expects to improve operational efficiency in a number of ways, including by improving safe and efficient employee access to the system, reducing costs associated with refurbishing and supporting non-standard assets, optimizing procurement and supply chain by reducing the number of different equipment standards on the system, and reducing line losses on 4 kV feeders. The upgrade of feeders from 4 kV to 13.8 kV or 27.6 kV feeders is expected to improve the capacity to connect customers, resulting in more cost-efficient connections. The replacement of deteriorating and obsolete cable types from the system is anticipated to reduce the potential exposure to lead and asbestos classified as Designated Substances under the *Occupational Health and Safety Act*.[71] Furthermore, this initiative is also expected to reduce costs associated with maintaining non-standard assets (e.g., PILC and AILC cable), reduce line losses and increase feeder capacity to connect customers as legacy undersized cable 250 or 350 PILC cables are upgraded to standard 500 kcmil TRXLPE.

- **Area Rebuilds:** When planning projects, Toronto Hydro uses cost-benefit and risk evaluation principles to identify opportunities to bundle multiple assets of different types into area rebuild projects. This approach reduces the risk of needing to travel and set-up in a project area on multiple occasions in a short timeframe, thereby reducing the overall cost of replacing the relevant assets and the frequency of disruption to customers. By taking this approach in programs such as Overhead System Renewal (Section E6.5) and Underground System Renewal – Horseshoe (E6.1), the utility aims to mitigate the overall cost of its System Renewal program over time.
- **Flexibility Services:** Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. From the 2025-2029 period Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. This translates to deferred and more likely avoided capital expenditures in the range of $10 million, at a projected cost of about $5.7 million in operating expenditures.
- **Safety and Environmental Costs:** Employee and public safety is paramount for Toronto Hydro and a significant driver of capital investment during the 2025-2029 period. By investing in the sustainment and improvement of safety outcomes, the utility supports secondary financial benefits, such as a decrease in Workplace Safety Insurance Board premiums resulting from the utility's safety record. Toronto Hydro's emphasis on safety not only protects its workforce and the public but also generates significant cost savings. With an exemplary safety record, the utility benefits from reduced Workplace Safety Insurance Board premiums, allowing for more resources to be allocated to vital projects and innovations. Additionally, their commitment to environmental sustainability through investments in renewable energy and eco-friendly practices not only reduces their

[71] RSO 1990, c. O.1

environmental impact but also leads to lower operating costs, ensuring both financial stability and responsible resource management.

- **Advanced Technological Solutions**: By effectively harnessing advanced technology solutions, such as infrared thermography for early anomaly detection, electronic maintenance sheets for streamlined data handling, and online partial discharge testing for proactive maintenance. Toronto Hydro can significantly enhance its work coordination during maintenance outages. This approach allows for timely identification and resolution of potential issues, leading to reduced equipment failures and unplanned downtime. Ultimately, the adoption of these cutting-edge tools fosters cost-saving measures while bolstering the overall reliability and performance of the electrical grid.
- **Facilities Asset Management System:** Toronto Hydro has a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. Through this proactive facilities management system, Toronto Hydro minimizes unnecessary expenditures on premature asset replacements, translating into significant cost savings. By precisely identifying assets in poor condition and approaching replacements strategically, Toronto Hydro can allocate its financial resources more effectively, investing in critical areas that contribute to the overall reliability and performance of its infrastructure. This approach not only emphasizes cost saving but also underscores Toronto Hydro's commitment to responsible and efficient asset management, benefiting both the organization and its customers in the long run.
- **Procurement:** Toronto Hydro maintains a strategic approach by utilizing a combination of internal and external resources to execute its extensive capital and maintenance programs. The utility employs a competitive procurement process to determine the majority of costs associated with its capital work program. Despite anticipated challenges like rising construction costs due to labor market pressures and increased congestion in Toronto, the utility's competitive procurement strategy remains instrumental in securing essential resources at reasonable rates, ensuring the successful execution of the capital plan while emphasizing cost-effectiveness. This strategic approach enables Toronto Hydro to manage financial resources efficiently, ultimately benefiting both the organization and its customers. Additionally, major world events like the COVID-19 pandemic, changes to work patterns, geopolitical conflict, and high inflation significantly disrupted the global supply chain. This led to risks in timely and cost-effective material procurement. To address these challenges

and ensure a reliable supply, Toronto Hydro updated its strategy. This revised approach includes a comprehensive assessment of supply chain risks and a mix of proactive long-term measures and reactive short-term actions. The strategy takes a 360-degree view of Toronto Hydro's current and into the short- and medium-term, as informed by engagements with business units, while simultaneously keeping track of market conditions through touchpoints with vendors and manufacturers.

In addition to the above initiatives, Toronto Hydro's overall risk-based approach to system renewal and enhancement is expected to drive value, including cost savings, over the long-term by ensuring that decisions on when to replace assets are informed by quantitative analysis and measurement. In the context of Toronto Hydro's large asset renewal backlog, risk-based approaches allow the utility to target assets that carry the greatest amount of risk cost based on age, condition, configuration, loading, and other considerations, ensuring that priorities are set in a manner that maximizes value-for-money over the long-term. For more information on Toronto Hydro's asset management lifecycle optimization and risk management approaches, please see Section D3.

A6 Capital Expenditure Plan

A6.1 Capital Programs and Drivers

The 2025-2029 Capital Expenditure Plan in the DSP consists of 20 unique capital programs. These programs are allocated to each of the OEB's four major investment categories, as defined in Table 10, based on their trigger drivers, which represent the primary reason a program must be carried out.

Table 10: Capital Investment Categories

System Access	• Toronto Hydro fulfills its obligation by undertaking necessary modifications, such as asset relocation, to ensure that customers, including generators, or groups of customers, can seamlessly access and benefit from reliable electricity services through the distribution system.
System Renewal	• Toronto Hydro optimizes its distribution system by strategically replacing and refurbishing system assets. This proactive approach ensures the reliability of electricity services for customers by managing failure risk as the utility maintains a robust infrastructure capable of meeting their energy needs in the short and long terms, while also investing in improving system resiliency.

System Service	• Toronto Hydro proactively modifies its system to effectively meet operational objectives, improve efficiency, and anticipate future customer electricity service requirements. The utility modernizes its grid to ensure reliable and efficient service delivery for its customer in line with evolving demands.
General Plant	• Toronto Hydro proactively undertakes modifications, replacements, or additions to assets beyond the distribution system, encompassing land, buildings, tools, equipment, rolling stock, and electronic devices and software. These efforts are geared towards supporting the utility's day-to-day business and operational activities, fostering efficiency, reliability, security, and adaptability in delivering energy services to its customers.

Each capital program is defined by a single trigger driver and a number of secondary drivers. The trigger drivers for Toronto Hydro's 2025-2029 DSP programs are summarized in Table 11, below. Although safety is not listed as a trigger driver, it is a significant secondary driver for many programs – especially those that are triggered by asset Failure or Failure Risk in the System Renewal category. Secondary drivers may be as, or more, consequential than the trigger drivers. Details on the trigger and secondary drivers for each program are provided in the detailed program justifications in Sections E5 through E8 of the DSP.

Table 11: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and distributed energy resource ("DER") customers to its system as efficiently as possible in alignment with its obligation under the *Distribution System Code*. This obligation holds unless it poses safety concerns for the public or employees or compromises the reliability of the distribution system. In situations where the existing infrastructure falls short of enabling a connection, the utility undertakes system expansions or enhancements to accommodate the customer's needs.
	Mandated Service Obligation	• Toronto Hydro prioritizes full compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• Specific asset types and configurations can become obsolete for a variety of technical and operational reasons. Typically, functionally obsolete assets can no longer be effectively maintained or utilized as intended. Toronto Hydro will act to

Category	Driver	Description
		retrofit or replace these assets within a timeframe that is specific to the unique circumstances of the asset population in question.
	Failure	• Toronto Hydro must reactively repair or replace assets or critical components that have failed while in service.
	Failure Risk	• Toronto Hydro takes proactive measures to identify, assess, and mitigate failure risk within its asset populations. Failure risk is determined by evaluating the likelihood of failure (e.g., by leveraging asset condition assessments) and the likely impact of failure ("criticality") on various outcomes, including safety, reliability, cost, and the environment. By prioritizing service reliability and ensuring the safety of workers and the public, the utility strives to maintain a robust infrastructure that meets the evolving needs of its customers.
System Service	***Reliability***	• Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions.
	Capacity Constraints	• Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs.
General Plant	***Operational Resilience***	• Toronto Hydro prioritizes the ability to mitigate and recover from disruptions to core business functions. Through robust strategies, contingency plans, and proactive risk management, the utility ensures prompt restoration of operations, minimizing impact and maintaining service continuity.
	System Maintenance and Capital Investment Support	• Toronto Hydro recognizes the significance of investing in day-to-day operational activities, as doing so enables the utility to prioritize the safety and well-being of its employees while maintaining an environment that fosters efficiency and reliability in delivering essential services.

A6.2 2020-2029 Capital Expenditure Plan

Table 12 shows the level of spending for the System Access, System Renewal, System Service, and General Plant investment categories, as well as the System O&M expenditures over the historical period from 2020 to 2024 and over the forecast period from 2025 to 2029. A detailed discussion of expenditure variances and trends over the 10-year 2020-2029 period is provided in Section E4.

1 **Table 12: Historical (2020 to 2024) and Forecast (2025 to 2029) Expenditures ($ Millions)**

Category	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	226.5	239.3	228.3	192.8	184.8
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.3	83.0	95.1	101.2
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6
Other	17.4	4.6	12.8	12.6	7.7	6.3	7.0	8.7	10.3	12.0
Total CapEx	448.1	533.2	597.9	582.9	625.3	734.6	767.3	836.2	837.9	825.7
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

Detailed analysis for each program is included in Sections E5 through E8 of the DSP, including analysis of historical expenditures and accomplishments, justifications for 2025-2029 expenditures, and options analysis.

A7 Outcomes and Performance Measurement

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[72] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework ("RRF") categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made reflect a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the

[72] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

performance measures identified in each category of the custom scorecard (see Table 13 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 13: 2025 – 2029 Performance Incentive Scorecard Measures

Performance	Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

A8 Third-Party Studies and Reports

The 2025-2029 DSP is supported by a several expert studies and reports.

Table 14: Third-Party Studies Filed in Support of the 2025-2029 DSP

Study	Vendor	Description/Reference
Econometric Benchmarking of Historical and Projected Total Cost and Reliability	Clearspring	Clearspring was retained to apply econometric modelling to benchmark the utility's historical and projected costs and reliability. The purpose of this review was to assess the reasonableness of Toronto Hydro's revenue forecasts and inform the appropriate stretch factor in the utility's Application. Clearspring compared Toronto Hydro's historical and projected total costs against its benchmark costs i.e. the Toronto Hydro's expected costs in any given year based on the econometric model. Clearspring's results indicated that (i) the historical average total costs for the utility, from 2020 to 2022, are 28.0 percent below benchmark expectations; and (ii) the projected total cost levels during the 2025-2029 period are 22.9 percent below benchmark expectations. Based on their findings, Clearspring states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.15 percent. Clearspring also benchmarked Toronto Hydro's reliability performance, finding that the average frequency of interruptions (SAIFI) was above the predicted benchmark by 98.8 percent, but the customer average interruption duration (CAIDI) was below benchmark by 104.1 percent. The study can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix A.
Unit Costs Benchmarking Study	UMS Group	UMS Group was retained to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in unit costs for major asset classes and maintenance activities for the 2020-2022 period. UMS compared these results to those of peer utilities across North America, considering dollar and metric conversions and accounting differences. Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. UMS also noted that if certain qualitative considerations, such as customer density, were statistically normalized for, Toronto Hydro's comparative ranking would be better than shown. The study can be found at Exhibit 1B, Tab 3, Schedule 1, Appendix C.

Study	Vendor	Description/Reference
Climate Change Vulnerability Assessment Update	Stantec	To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol. The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model. In 2022, Toronto Hydro retained Stantec to update the 2015 study, which recommended not relaxing any adaptation measures from the previous study. This information informed the development of Toronto Hydro's 2025-2029 DSP. The study can be found at Exhibit 2B, Section D2, Appendix A.
Enterprise IT Cost Benchmark & Functional Maturity Assessment	Gartner Inc.	To assess the reasonableness of the utility's level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting ("Gartner"). Gartner concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers and the increase in Toronto Hydro's 2022 IT spending compared to 2017 is similar to industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending (51.2 percent of IT spend for Toronto Hydro versus 41.9 percent for peers, largely due to the Customer Information System ("CIS") Upgrade and IT Management and Administration (14.8 percent of IT spend for Toronto Hydro versus 10.8 percent for peers, largely due to increased investment in Cyber Security services)." The study can be found at Appendix A to Exhibit 2B, Section D8.

Study	Vendor	Description/Reference
Future Energy Scenarios Report	Element Energy	To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy, who has developed a Future Energy Scenarios modelling tool. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation, and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. The report can be found at Appendix B, to Exhibit 2B, Section D4.
Review of ACA Modelling Enhancements and Customisations	EA Technology	Toronto Hydro retained EA Technology to guide and review improvements to its ACA methodology, to ensure that it continues to align with the core principles of the Common Network Asset Indices Methodology ("CNAIM"), as well as to identify opportunities for continuous improvement. EA Technology found that Toronto Hydro has made significant progress, while retaining alignment with CNAIM, but expects it to continue to evolve as part of natural process, providing specific areas for improvement. The report can be found at Exhibit 2B, Section D3, Appendix B.

B Coordinated Planning with Third Parties

B1 Introduction

This section provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, and how those consultations affect Toronto Hydro's Distribution System Plan ("DSP"). Toronto Hydro has a robust approach to coordinating and integrating third-party infrastructure planning information into its distribution system planning process. The utility coordinates infrastructure planning with a wide-range of external stakeholders including: customers (e.g., large customers, subdivision developers, and municipalities), the Independent Electricity System Operator (IESO), the transmitter ("Hydro One") and other distributors as part of regional planning process, and other entities and agencies such as telecommunication and transit providers (e.g. Metrolinx).

Generally, Toronto Hydro coordinates with third parties by participating in forums and processes that are organized and led by governmental or delegated authorities. For example, Toronto Hydro exchanges planning documents and project execution information with large developers and telecommunication entities through municipal planning and permitting processes. The City of Toronto requires infrastructure entities to circulate their plans in order to obtain permits to carry out work. Please see Section B2 Customer Coordination below for further details about Toronto Hydro's participation in the City of Toronto's infrastructure planning coordination activities.

Similarly, Toronto Hydro engages with the transmitter and other distributors, along with other local stakeholders through the IESO's Regional Planning Process ("RPP"). The RPP is part of the IESO's statutory mandate to conduct independent planning for electricity generation, demand management, conservation and transmission.[1] Given the high degree of technical alignment needed between upstream transmission assets and downstream distribution assets, the RPP requires close coordination between the IESO and transmission and distribution utilities. Please see Section B3 Electricity System Planning below for further details about Toronto Hydro's participation in RPP.

Regulations recently came into effect requiring distributors to consult any telecommunication entity that operates within its service area for the purpose of distribution system planning.[2] Please see

[1] Section 6(1) of the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A
[2] *Supporting Broadband and Infrastructure Expansion Act, 2021.* Ontario Regulation. 842/21 made under the *Ontario Energy Board Act,* S.O. 1998, Ch 15, Sched. B.

Section B4 – Telecommunication Entities below for an overview of the utility's processes for coordinating infrastructure planning with telecommunication entities within its service territory.

B2 Customer Coordination

B2.1 Overview

Toronto Hydro coordinates infrastructure planning with customers including large developers and infrastructure agencies, as well the City of Toronto. These engagements provide Toronto Hydro key planning information that can be integrated into the utility's Peak Demand Forecast described in Section D4 - Capacity Planning and Electrification. They also enable effective operational planning and execution of major infrastructure relocation projects, as well as capital projects more generally.

B2.2 Proactive Customer Engagement

Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects to understand their needs, determine their load requirements and timelines, provide technical guidance, explore innovation opportunities, and provide support in understanding the connection process.[3] These engagements usually occur up to five to eight years before an intended connection materializes, enabling a smoother connection experience for customers and providing Toronto Hydro with valuable insight into emerging technologies that customers are adopting behind-the-meter, that can drive significant load growth or change in demand patterns in certain parts of the grid. Accordingly, these engagements enable Toronto Hydro to incorporate anticipated connections into its Peak Demand Forecast with a higher degree of confidence. Based on this forecast, Toronto Hydro determines investment needs in demand-driven program such Stations Expansion and Load Demand, to manage capacity constraints and plan for future load growth on the distribution system. For further information please refer to sections E5.3 Load Demand and E7.4 Stations Expansion.

B2.3 External Requests

Toronto Hydro manages a large number of requests by third parties to relocate distribution assets in order to accommodate public infrastructure such as city works, roads and highways and other types of development projects such as public transit. When a request for relocation is received, Toronto

[3] The Development Planning team works with the Key Accounts team who is responsible for managing relationships with customers and developers. For more information about Key Accounts please refer to Exhibit 4, Tab 2, Schedule 9.

Hydro also reviews load demand projections in the vicinity of the project(s) to evaluate whether there are opportunities to efficiently increase capacity in conjunction with the relocation work. When capacity needs are identified in the surrounding area, Toronto Hydro integrates expansion work into the third party's relocation project. For more information please refer to section E5.2 Externally Initiated Plant Relocations and Expansion.

B2.4 Capital Program Delivery

Toronto Hydro coordinates the execution of its capital work with the City of Toronto through use of the City of Toronto Project Tracking Portal ("PTP") as well as regular meetings with the City of Toronto's Infrastructure Coordination Unit ("ICU") and the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC").[4][5] The ICU acts as a coordinating body for all groups – not just City agencies – that perform construction work in the city. This coordination often enables construction by different groups to be bundled together, avoiding additional disruption.[6] The TPUCC is a consortium established by the City of Toronto and utility companies to provide a forum for discussion in order to table ideas, encourage safety and implement innovative ways of reducing the impact and inconvenient of construction projects. Membership of the TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto including, Toronto Hydro, Enbridge Gas Distribution, Enwave Energy Corporation, Hydro One Networks Inc. Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Toronto Transit Commission. These engagements allow Toronto Hydro to resolve conflicts between its capital program and the City of Toronto, including by fast tracking or postponing projects to better align with other scheduled projects.

Toronto Hydro also responds to requests to adjust its work in response to social and cultural programs, such as filming requests and City of Toronto programs that permanently or temporarily affect the use of public sidewalks and roadways including CaféTO (for restaurant and bar spaces) and ActiveTO (for physical activity, community safety, and cycling spaces).

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[4] City of Toronto, Infrastructure Viewer, online, https://map.toronto.ca/toinview/

[5] More information on the TPUCC and construction coordination in the City can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/

[6] City of Toronto, Construction Coordination in the City, online, https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/

B3 Electricity System Planning

Toronto Hydro participates in the electricity system planning processes, particularly the Regional Planning Process, which produces the Toronto Region Integrated Regional Resource Plan (“IRRP”), led by the Independent Electricity System Operator (“IESO”), and in the Regional Infrastructure Plans (“RIP”) for the Toronto Region and Greater Toronto Area (“GTA”) North Region, led by Hydro One Networks Inc. Toronto Hydro’s DSP has been informed by the results of the completed regional plans, and Toronto Hydro continues to coordinate with the aforementioned parties with respect to plans that are under development. The following sections describe the coordinated planning approach and results from the ongoing Regional Planning Process.

B3.1 Regional Planning Process Consultations

Regional planning looks at supply and reliability issues at regional and local levels with a focus on the 115 kV and 230 kV portions of the provincial system. The provincial grid is divided into several regions or zones for which plans are developed.

Regional planning focuses on the facilities that provide electricity to transmission-connected customers such as distributors and large directly-connected customers. This typically includes the transformer stations that supply the load and the transmission circuits between the stations. It also includes the 115 kV and 230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers local distributed generation, Conservation and Demand Management (“CDM”), as well as other forms of Non-Wires Solutions (“NWS”) that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies (“LDCs”) conduct wires and NWS planning at the distribution level and coordinate with the transmitter and the IESO mainly on transmission supply facilities. Toronto Hydro has coordinated new or enhanced transmission supply facilities for some of its stations. These are discussed in more detail below in Section B3.2.

Regional planning can overlap with provincial system planning and distribution system planning. At Toronto Hydro, the same people responsible for the planning that informs the distribution system plan are also involved in regional planning. Overlaps with distribution system planning occur largely at the transformer stations that supply distributors, and at large directly-connected customers. For example, co-ordination is necessary when planning for the construction of new transformer stations such as the recently completed Copelands TS that serves the expanded downtown core. Regional planning may also require coordination with distribution planning when a distribution solution can address needs of the broader local area or region, for example, by providing load transfers between transformer stations.

The following subsections describe key elements of the regional planning consultations. This is an iterative process and consultations occur at different points throughout the regional planning process.

B3.1.1 Stakeholder Consultations

The Regional Planning Process includes community and stakeholder engagement, including webinars, led by the IESO. The IESO invites the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the Scoping Assessment Outcome Report and development of the IRRP that is currently underway. The inaugural webinar occurred in March 2023, and coincided with the publication of the Scoping Assessment Outcome Report. Based on discussions with the IESO, Toronto Hydro understands that stakeholder consultation on the demand forecast and supply/delivery options and recommendations will take place after the filing of the Application.

B3.1.2 Transmitter Consultations

Toronto Hydro consults with Hydro One through regional planning processes, and in particular the RIP which is led by the transmitter.

Hydro One launched the new regional planning cycle in August 2022, starting with a Needs Assessment update. The Toronto Region Needs Assessment Report was completed in December 2022, and is provided as Appendix A to this section.

The most recent Metro Toronto RIP, that covers Toronto Hydro's service area, was completed in March 2020.[7] The most recent GTA North RIP, that covers a neighbouring region important to Toronto Hydro's operations, was completed in October 2020.[8] Both reports are being updated through the regional planning cycle currently underway.

[7] Exhibit 2B, Section B, Appendix B – Toronto Regional Infrastructure Plan (March 2020).
[8] Exhibit 2B, Section B, Appendix C – GTA North Regional Infrastructure Plan (October 2020).

B3.1.3 Other Distributor Consultations

Toronto Hydro is not an embedded LDC, and does not supply any embedded LDCs. Therefore, the utility's planning consultations with other LDCs typically occur in the context of regional planning.

B3.1.4 IESO Consultations

Toronto Hydro actively consults with the IESO as part of Integrated Regional Resource Plan ("IRRP"). The most recent IRRP was completed in 2019.[9] The IESO launched a new IRRP process for the Toronto Region in the spring of 2023. Toronto Hydro is the host distributor for that IRRP and is actively consulting with the IESO, Hydro One and other stakeholders, including the City of Toronto and the public.

B3.1.5 Municipality Consultations

As part of the Regional Planning process, Toronto Hydro, the IESO, and Hydro One engage with the City of Toronto. Through these engagements, the planners put their demand forecasts and supply/delivery options and recommendations to the municipal government for feedback with the goal of aligning expectations based on the plans and priorities of the City of Toronto.

B3.2 Regional Planning Process

Distribution system planning provides inputs to regional planning through peak demand forecast that triggers a needs assessment. Planning considerations in the Toronto Region include:

- A large load that is dynamic in the city area;
- A significant number and density of transmission lines and stations;
- The presence of large generation; and
- A customer base that has experienced, and is sensitive to, major events that disrupt continuity of service.

To facilitate infrastructure planning, the IESO divides Ontario into planning regions. As planning considerations change, the boundaries of these regions are revised. In the past, Toronto Hydro's service area was split between Central Toronto and Northern Toronto. More recently, regional planning considers Toronto Hydro's service area, the City of Toronto, on a consolidated basis as the Toronto Region. Planning documents and reports that have been developed, issued, and relied upon

[9] Exhibit 2B, Section B, Appendix D – Toronto IRRP Report (August 2019).

for Toronto Hydro's plans for the 2025-2029 period are based on the planning region being the Toronto Region. Planning triggers such as changes in demand or asset condition, initiate the regional planning process and progresses through the following phases:

i. Needs Assessment (NA);
ii. Scoping Assessment;
iii. Integrated Regional Resource Plan (IRRP); and
iv. Regional Infrastructure Plan (RIP).

B3.2.1 Needs Assessment

The lead transmitter in a given region, in this case Hydro One, coordinates and leads the Needs Assessment phase with input from the local LDC(s) and the IESO. Combined, they constitute what is known as the Study Team. The Study Team is provided with a range of inputs from both the LDC, in the form of a peak demand forecast, and the IESO in the form of CDM and DER penetration forecasts. The needs of the various high voltage assets in the region are then identified over the medium and long term to ensure adequate capacity is available to connect forecasted load while continuing to operate the grid in a reliable and safe manner. At the conclusion of the Needs Assessment, the Study Team will categorize asset needs as either requiring further regional planning coordination involving more advanced stages of the process or local planning between the affected LDC and lead transmitter only. Toronto Hydro and Hydro One completed a Needs Assessment in December 2022, the details of which are in Appendix A. This report reflects key aspects of the Stations Expansion Program in section E7.4

B3.2.2 Scoping Assessment

If the Study Team recommends that additional planning is required to assess a particular need or group of needs, the IESO then initiates a Scoping Assessment phase and leads the process in collaboration with the host LDC, in this case Toronto Hydro, and the lead transmitter, Hydro One. A thorough review of the needs identified in the Needs Assessment phase is conducted with an aim to determine if a mix of wires and non-wires solutions – which may comprise conservation and demand management, and distributed generation or energy storage – can address the identified needs. Needs that can benefit from an integrated (wires plus non-wires) solution proceed to an IRRP, while those that can only benefit from a wires solution proceed to the RIP process led by Hydro One. The

IESO completed the Scoping Assessment report in March 2023, which can be found in Appendix E to this section.[10]

B3.2.3 Toronto Integrated Regional Resource Plan

The Toronto Region IRRP is currently underway. The IESO is the lead, working with Hydro One (the transmitter) and Toronto Hydro (the sole LDC).

The purpose of the IRRP is to ensure that the electricity service requirements of the Toronto Region are served by an appropriate combination of demand and supply options that reflect the priorities of the community. Planning activities include forecasting the expected growth in electricity demand for 25 years, and investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the Toronto Region**.** The result of the planning process is an integrated plan, with a long-term perspective, which recommends a balance of options that account for costs, reliable electricity service, and mitigation of environmental impacts. The regional planning cycle underway for the Toronto Region is scheduled for completion in August 2024, and the impact of the regional plan on the DSP is discussed in Section E2.4.1.

B3.2.4 Toronto Regional Infrastructure Plan

The previously prepared Metro Toronto RIP was completed in March 2020 and is attached as Appendix B to this section.

The Toronto RIP for the current cycle is scheduled for completion in March 2025. This plan is the final phase of the regional planning process following the completion of the Toronto Region's IRRP by the IESO in August 2024. The RIP may be triggered earlier if a particular need identified in the IRRP cannot be met by a non-wires solution. At that point, the IESO requests Hydro One to initiate a RIP.

B3.2.5 GTA North Regional Infrastructure Plan

The GTA North RIP was completed in October 2020. The plan is attached as Appendix C to this section.

The RIP was the final phase of the regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It followed the completion of the York Sub-

[10] Exhibit 2B, Section B, Appendix E – Toronto Scoping Assessment Outcome (March 2023).

Region Integrated Regional Resource Plan by the IESO in February 2020. Because Toronto Hydro also receives supply from the GTA North Region, Toronto Hydro is a participant of the process.

Participants of the RIP included:

- Alectra Utilities;
- Hydro One Networks Inc. (Distribution);
- Independent Electricity System Operator;
- Newmarket-Tay Power Distribution Ltd.; and
- Toronto Hydro Electric System Limited.

Toronto Hydro provided input to the GTA North Region Needs Assessment. The purpose of the Needs Assessment report is to assess if there were regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant LDCs and Hydro One and other parties as required.

Hydro One launched a new GTA North regional planning cycle in March 2023, starting with a Needs Assessment update. The Needs Assessment Report for the GTA North Region was completed on July 14. 2023, and is attached in Appendix F to this section.[11] Impacts to the DSP are described in Section E2.4.1.

B4 Telecommunication Entities

B4.1 Overview

Toronto Hydro mainly relies on two consultation processes to ensure comprehensive, timely, and efficient coordination of infrastructure planning and capital project execution with telecommunication entities ("telecoms") that operate within its service area.

The first consultation process is facilitated through the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC"), which meets once a month. Any telecom that operates within the City of Toronto is required to participate in the TPUCC in order to obtain construction permits. This forum provides Toronto Hydro a comprehensive view and opportunity to engage all telecoms that operate within its service area. The second consultation process is Toronto Hydro's attachment

[11] Exhibit 2B, Section B, Appendix F – GTA North Region Needs Assessment (July 2023).

process. Telecoms who seek to attach their infrastructure to Toronto Hydro's assets must apply and coordinate with Toronto Hydro to obtain approval.

Sections B4.2 and B4.3 below provide further details about these processes and insight into how Toronto Hydro effectively and efficiently coordinates with telecommunications entities that operate within its service area. Section B4.4 explains how telecom consultations affect the utility's capital plan.

B4.2 Municipal Forums

The City of Toronto imposes permitting requirements for the installation of infrastructure within the city of Toronto.[12] In order to maximize the efficiency of infrastructure coordination, the City of Toronto formed the TPUCC.[13] The TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto. In addition to Toronto Hydro, other members of the TPUCC include Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Hydro One Networks Inc.

In order to be granted permits from the City of Toronto, telecoms must submit "circulations", containing plans mapping out telecom facilities and details around the execution of the capital projects. These plans are circulated to other members, including Toronto Hydro. The utility examines the plans and ensures that they are compliant with Toronto Hydro's design and construction standards, especially where they are adjacent, or directly affixed to, Toronto Hydro's infrastructure. The circulations process provides a robust forum for consultation and co-ordination between Toronto Hydro and telecommunications entities operating in its service territory.

Since 2020, telecoms including Beanfield, Bell Canada, Rogers Cable and Cogeco have submitted over 3,200 circulations containing plans on capital project design and execution. Toronto Hydro processes these requests within an average of 5.4 days, reviewing and identifying whether there are any conflicts or contraventions of Toronto Hydro's design and construction standards (e.g., if adjacent infrastructure is planned to be constructed in close proximity to Toronto Hydro's poles). The utility typically resolves conflicts or contraventions identified in an average of four days.

[12] More information on Municipal Consent Requirements can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/construction-standards-permits/standards-for-designing-and-constructing-city-infrastructure/?accordion=utility-cut-permit-applications-and-municipal-consent-requirements-mcr.
[13] *Supra* Note 5

This information sharing process occurs on a rolling basis as TPUCC members upload data on the City of Toronto's Project Tracking Portal ("PTP") and Infrastructure Viewer application ("T.O.INview"). This means that Toronto Hydro regularly accesses the most up-to-date information on telecom capital project plans and similarly, telecoms can readily access Toronto Hydro's capital project plans. Toronto Hydro, Rogers Cable, and Bell Canada are also members of the Digital Map Owners Group ("DMOG"), which is responsible for the sharing of costs and maintenance of a comprehensive database mapping out underground utility features across the City of Toronto.

B4.3 Attachment Process

Separately, Toronto Hydro manages an attachment permitting process, where third-parties including telecoms, proactively request to affix their facilities onto Toronto Hydro's assets. Initially, Toronto Hydro requests advance notice and details of attachment applications from all telecoms operating within the City of Toronto for the upcoming year. However, the bulk of the permit applications are submitted on an ongoing basis. Toronto Hydro processes the applications and assesses whether the targeted assets are capable of physically supporting third-party fixtures or whether additional work is required in the form of "hydro make-ready" (HMR) work.

Toronto Hydro cross-references the HMR projects submitted through the attachment permitting process with projects in queue on the City's PTP and T.O.INview systems, and other Toronto Hydro programs, falling mainly under System Renewal category at Section E6. Where cost-effective and efficient, Toronto Hydro incorporates the HMR work into existing projects or otherwise assigns it to a contractor pre-approved by Toronto Hydro to complete the work on behalf of the telecom in accordance with Toronto Hydro's design and construction standards.

B4.4 Effects of Telecom Consultations on Capital Plans

Inputs gathered through the telecom consultations processes described above are reflected in programs under the System Renewal category of Toronto Hydro's capital plan. Specifically:

- **Area Conversions (Exhibit 2B, Section E6.1)**: This program converts pole-top box constructions to new designs, to which third-party assets – including telecom fixtures – are often attached. Toronto Hydro cross-references its program execution plans with telecom information obtained through the attachment process in order to come up with a schedule and plan that is responsive to the needs of telecoms.

- **Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)**: This program replaces underground network assets to manage failure risk. In order to complete this work, Toronto Hydro accesses its underground assets through trenches. Telecoms often situate their fibre optic networks in Toronto Hydro's underground cable chambers in the ducts. Therefore, Toronto Hydro often cross references information from telecoms that come through TPUCC circulations, which may result in, for example, modifications to trench routes to accommodate any telecom projects.
- **Overhead System Renewal (Exhibit 2B, Section E6.5)**: This program replaces poles that are in poor condition. Toronto Hydro cross references applications for wireline attachments with its own project execution plans to coordinate the pacing and order, and if needed plan any required transfers of existing telecom assets to an alternative pole.

B5 IESO Comment on Renewable Energy Generation

B5.1 IESO Comment Letter

In accordance with section 5.2.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, Toronto Hydro requested and obtained a letter of comment from the IESO with respect to planned renewable energy generation ("REG") investments. This letter is filed at Appendix G to this section.

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Toronto Region

Date: December 19, 2022

Prepared by: Toronto Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Toronto Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Toronto Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	August 23, 2022	**END DATE**	December 19, 2022

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in August 2022 for the Toronto Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Toronto Region NA includes:
a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment;
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Toronto Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The information was based on what was available and provided at the time of the NA, which does not include the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. This will be further assessed in the next phase of this RP cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:
a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification. (which does not consider the impact from the "Pathways to Decarbonization" report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle)

6. NEEDS

Needs that were identified in the last RP cycle with associated projects recently done or currently underway are:

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be done in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be complete in 2025. Transformer T1, T2 and T4 have been replaced in 2019-2021. The condition of transformer T3 and the 115 kV breakers are reviewed and considered in fair condition; no replacement in the near/medium term is needed.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026.

Other near/medium-term needs identified in the previous RP cycle and the new near/medium-term needs identified in this NA are:

Identified in the previous RP cycle	Identified in this NA
Line Capacity (Refer to section 7.2 for more details) • Richview to Manby 230 kV Corridor [2026] • Manby to Riverside Jct 115 kV Corridor [2026, with a line upgrade expected by 2028] Transformers / Autotransformers Requiring Replacement (Refer to section 7.1 for more details) • Charles TS: T3/T4 [2026] • Duplex TS: T1/T2 [2026] • Scarboro TS: T23 [2027] • Fairchild TS: T1 [2028] • Bermondsey TS: T3/T4 [2029] • Manby TS: autotransformers T7, T9, and T12, and step-down transformer T13 [2029-2030] • Leslie TS: T1 [2030] Transmission Lines Requiring Replacement (Refer to section 7.1 for more details) • H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. 115 kV overhead section [2025] • L9C/L12C: Leaside TS to Balfour Jct. 115 kV overhead section [2027]	Transformers / Autotransformers Requiring Replacement (Refer to section 7.1 for more details) • Strachan TS: T14 & T13/T15 [2025, 2031] • Basin TS: T3/T5 [2027] • Scarboro TS: T23 [2027] • Fairchild TS: T3/T4 [2028] • Malvern TS: T3 [2029] • Manby TS: T14 [2029] • Duplex TS: T3/T4 [2031] Load Restoration (Refer to section 7.4) • Loss of C14L/C17L • Loss of C18R/P22R

The long-term needs that were identified in the previous RP cycle and this NA are [beyond 2031]:

Identified in the previous RP cycle	Identified in this NA (Potential)
Station Capacity • Fairbank TS • Sheppard TS • Strachan TS • Basin TS Transformation Capacity • Manby W TS • Leaside TS Line Capacity • Leaside TS to Wiltshire TS 115 kV Corridor	Station Capacity • Glengrove TS • Finch TS / Bathurst TS • Warden TS Line Capacity • Parkway TS to Richview TS 230 kV Corridor

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need:
- Asset renewal needs for replacing the major HV equipment as listed in the table below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
- The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
- The load restoration and long-term needs as listed in the following table.

Further Regional Coordination Not Required	Further Regional Coordination Required
Asset Renewal Needs (Stations): • Strachan T14 & T13/T15 • Charles TS: T3/T4 • Duplex TS: T1/T2 & T3/T4 • Basin TS: T3/T5 • Scarboro TS: T23 • Fairchild TS: T1 & T3/T4 • Bermondsey TS: T3/T4 • Malvern TS: T3 • Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer • Leslie TS: T1 **Asset Renewal Needs (Lines):** • 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section • 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section **Line Capacity Need:** • 230 kV Richview TS to Manby TS Corridor **Station Capacity Need:** • Fairbank TS • Strachan TS	**Line Capacity Need:** • 115 kV Manby TS to Riverside Jct. Corridor **Load Restoration:** • Loss of C14L/C17L • Loss of C18R/P22R **Long-Term Needs:** • Sheppard TS – Station Capacity • Basin TS – Station Capacity • Glengrove TS – Station Capacity • Finch TS / Bathurst TS – Station Capacity • Warden TS – Station Capacity • 230/115kV Manby W Autotransformers – Transformation Capacity • 230/115kV Leaside TS Autotransformers – Transformation Capacity • 230 kV Parkway TS to Richview TS Corridor – Line Capacity • 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity

This NA assessment does not include or consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. The TWG recommends that this be assessed in the next phase of this RP cycle.

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1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update needs identified in the previous Toronto RP cycle, and recommend which needs require further assessment and regional coordination and which do not.

This report was prepared by the Toronto Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: Toronto Region TWG Participants

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Toronto Hydro-Electric System Limited ("THESL")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the Toronto Region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- Reaffirm and update needs/plans identified in the previous RP cycle;
- Identify any new needs resulting from this assessment;
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and

- Recommend which need(s) that do not require further regional coordination (i.e. can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region covers the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It includes the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the Toronto Region map. Electrical supply to this Region is provided by thirty-five 230kV and 115kV transmission and step-down stations as shown in Figure 2. The eastern, northern, and western parts of the Region are supplied by seventeen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and sixteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The region is also supplied locally by Portlands Energy Centre, a 550 MW combined-cycle power generating station. The sum of 2021 non-coincident summer station peak load of the Region was about 4,850 MW.

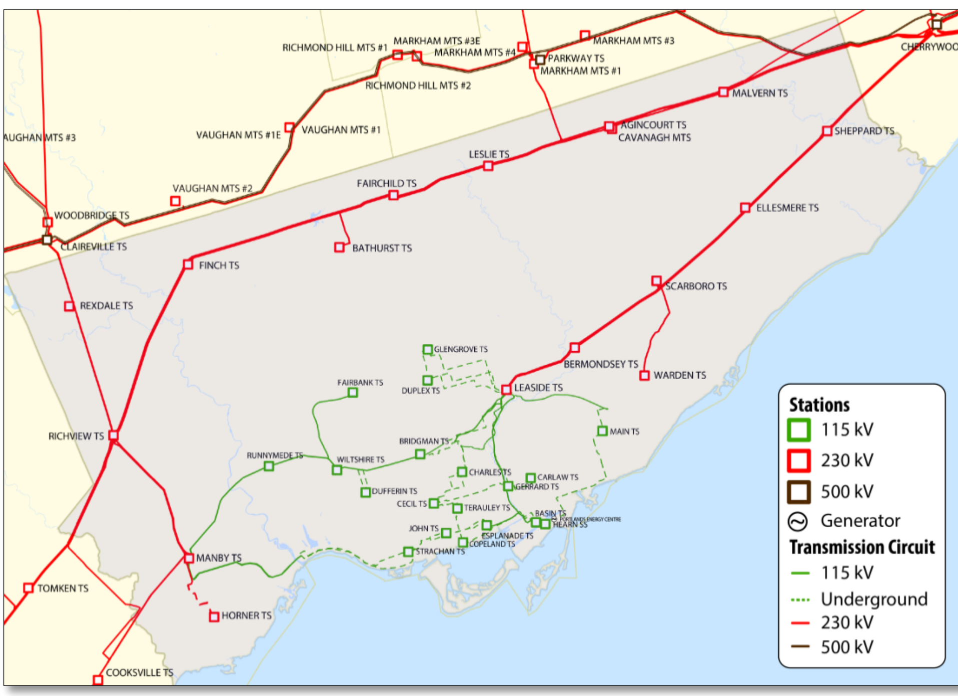

Figure 1: Toronto Region Map

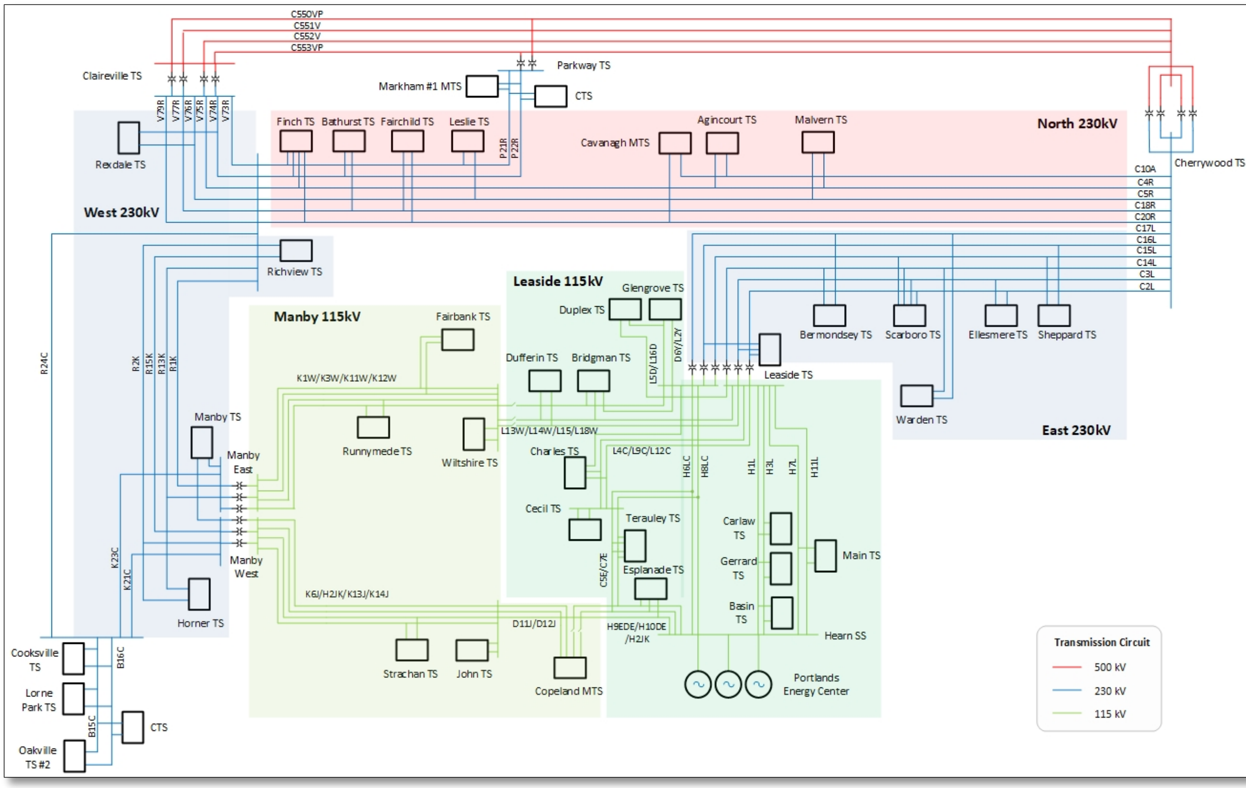

Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Toronto Region NA. The information provided includes the following:

- Load Forecast for all supply stations in the Toronto Region;
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the Toronto RP process.

The information provided was the most recent information available and provided at the time of the NA phase. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in October 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the RP process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP) (in cases where it has been produced by the municipality and the information can be translated by the LDC into the impact on peak demand). Accordingly, the OEB

RPPAG also recently developed a guideline called "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector", which lists the key MEP/CEP outputs to improve LDC load forecasts going forward. THESL has been closely coordinating with developers, provincial agencies and the City of Toronto on energy plans impacting various sections of the grid across the Toronto region. This NA report is recommending that further engagement be undertaken during the next phase of the RP cycle.

Also, it is important to be noted that, the IESO has just published the "Pathways to Decarbonization" on December 15, 2022, which evaluates a moratorium on the procurement of new natural gas generating stations in Ontario and develops an achievable pathway to decarbonization in the electricity system. It recommends that development work for priority transmission investments be identified to support decarbonization in the RP process. With this increasing focus on decarbonization and electrification, the electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this NA report. The TWG recommends that the "Pathways to Decarbonization" report and its subsequent impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region be considered and assessed in the next phase of this RP cycle.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Toronto Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the growth rates from the LDC load forecast to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. It is to be noted that even though the IESO did not have information on new and contracted DG coming into service within the planning horizon, THESL has assumed the existing DGs are to remain in-service in the base year when developing their load forecast. The extreme summer weather corrected net non-coincident peak and coincident peak load forecasts for the individual stations in the Toronto region are given in Appendices A-1 and A-2;
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment;
- System reliability and operational considerations;
- Asset renewal for major HV transmission equipment requiring replacement with consideration to “right-sizing”; and
- Sensitivity analysis to capture uncertainty in the load forecast (which does not consider the impact from the “Pathways to Decarbonization” report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle).

The following other assumptions are made in this report.

- The study period for this NA is 2022-2031.
- Transmission system adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

This section identifies any new needs in the Toronto Region, and reaffirms and provides an update on the near, medium, and long-term needs already identified in the previous RIP.

Needs that were identified in the previous RP cycle with associated projects recently completed or currently underway were reaffirmed and are briefly described below with relevant updates. These are not further discussed in later sections of this report.

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be completed in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be completed in 2025. Transformer T1, T2 and T4 were replaced in 2019-2021. Based on asset condition assessment, transformer T3 and the 115 kV breakers are not recommended for replacement in the near/medium term.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026. A 2.5 km tunnel between Esplanade TS and Terauley TS is to be built.

The planned in-service year for the above underway projects is tentative and is subject to change.

All the other near/medium-term needs and long-term needs are summarized in Table 2 and Table 3 respectively. The load restoration need was also reviewed and is discussed in Section 7.4.

Table 2: Near/Medium Term Needs Identified in Previous RIP [(1)] and/or this NA

Type of Needs	Near/Medium-Term Needs	NA Section	Timing	Recommended Plan / Status	RIP Report Section
Line Capacity	Richview TS to Manby TS 230 kV Corridor	7.2.1	2026	Project in estimate phase.	7.5
Line Capacity	Manby TS to Riverside Jct 115 kV Corridor	7.2.2	2028 [(3)]	Timing is advanced to 2026.	7.9.5
Asset Renewal Needs (Stations) [(2)]	Strachan TS: Transformers T14 & T13/T15	7.1.1	2025 2031	• T14 requires replacement with higher rated unit. • T13/T15 need replacement with higher rated unit in medium term.	NEW
	Charles TS: Transformer T3/T4	7.1.2	2026	T3/T4 require replacement with higher rated units.	2nd cycle NA
	Duplex TS: Transformers T1/T2 & T3/T4	7.1.3	2026 2031	• T1/T2 require replacement with higher rated units. • T3/T4 need replacement with higher rated unit in medium term.	2nd cycle NA NEW
	Basin TS: Transformers T3/T5	7.1.4	2027	T3/T5 require replacement with higher rated units.	NEW / 7.9.4
	Scarboro TS: Transformer T23	7.1.5	2027	T23 requires replacement with like-for-like unit.	NEW
	Fairchild TS: Transformer T1 & T3/T4	7.1.6	2028	T1 and T3/T4 require replacement with like-for-like units.	2nd cycle NA (T1), NEW (T3/T4)
	Bermondsey TS: Transformers T3/T4	7.1.7	2029	T3/T4 require replacement with like-for-like units.	7.7
	Malvern TS: Transformer T3	7.1.8	2029	T3 requires replacement with like-for-like unit.	NEW
	Manby TS: Autotransformers (T7, T9, T12), Step-down transformer (T13/T14)	7.1.9	2029 2030	• T13/T14 need replacement with similar unit per current standard. • T7/T9/T12 need replacement with similar unit per current standard. • 230 kV breakers are in fair condition; will not be replaced in the near term.	7.6, NEW (T14)
	Leslie TS: Transformer T1	7.1.10	2030	T1 requires replacement with similar unit per current standard.	2nd cycle NA
Asset Renewal Needs (Lines) [(2)]	H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	7.1.11	2025	Development and estimate work to initiate in 2023.	7.2
	L9C/L12C: Leaside TS to Balfour Jct. overhead section	7.1.12	2027	Development and estimate work to initiate in 2023.	7.3

(1) Includes needs identified in the previous RIP that do not have projects in execution yet.

(2) The replacement/refurbishment scope, timing, and prioritization are based on the best available information at the time, and are subject to change.

(3) Earliest in-service of reconductoring the overhead line K13J/K14J is expected to be around 2028 if the development and estimate work is to be initiated in 2023.

Table 3: Long-Term Needs Identified in Previous RIP and/or this NA

Type of Needs	Long-Term Needs	NA Section	Timing (2nd Cycle RIP)	Description / Update	RIP Report Section
Station Capacity	Fairbank TS	7.3.1	2030-2035	New Runnymede DESN and the underway transformers replacement at Fairbank TS will provide relief.	7.9.1
	Sheppard TS	7.3.2	2030-2035	Consideration may be given to utilizing the idle winding on transformers T1/T2.	7.9.2
	Strachan TS	7.3.3	2030-2035	Transformer T12 has been replaced with a 60/100 MVA unit. Station capacity will increase after T14 is replaced by 2025 and T13/T15 are replaced in the medium term.	7.9.3
	Basin TS	7.3.4	2030-2035	Station capacity will increase when transformers T3/T5 will be replaced with 60/100 MVA units by 2027.	7.9.4
	Glengrove TS	7.3.5	Beyond 2031	Glengrove TS is almost at capacity in 2031. The transformer replacement with higher rated units at Duplex TS will provide relief.	NEW
	Finch TS / Bathurst TS	7.3.6	Beyond 2031	Total load at Finch TS and Bathurst TS is almost reaching the combined station capacity in 2031. To be managed by load transfer between DESNs and nearby stations at distribution level in the near/medium term.	NEW
	Warden TS	7.3.7	Beyond 2031	Load demand near Warden TS exceeds its capacity from 2024. To be managed by load transfer to Scarboro TS at distribution level in the near/medium term.	NEW
Transformation Capacity	Manby W TS Autotransformers (T12)	7.3.8	2030-2035	Restricted by the lowest rated autotransformer unit T12. This unit is planned to be replaced by 2030 and will provide relief to this constraint.	7.9.6
	Leaside TS Autotransformers (T16)	7.3.9	2035-2040	Autotransformer T16 is potentially overloaded following circuit C14L, C15L, or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply if needed.	7.9.8
Line Capacity	230 kV Parkway TS to Richview TS Corridor	7.3.10	Beyond 2031	Some sections of the 230 kV circuits P21R and P22R near the Parkway TS end are approaching limit by 2031. The baseline forecast does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. This need may arise sooner.	NEW
	115 kV Leaside TS to Wiltshire TS Corridor		2035-2040	The Bayview Jct. x Balfour Jct. underground section of the 115 kV circuit L15 is potentially overloaded in the long term.	7.9.7

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second RP cycle, Hydro One and the TWG have identified some new major HV equipment replacement needs over the next 10 years in the Toronto Region, as shown in Table 4 below. These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. The scope, timing, and prioritization of these replacement needs are based on the current available information and are subject to change.

The major HV transmission equipment considered in this assessment includes the following:

- 230 / 115 kV autotransformers;
- 230 kV and 115 kV load serving step-down transformers;
- 230 kV and 115 kV breakers where:
  - Replacement of six breakers or more than 50% of station breakers, the lesser of the two; and
- 230 kV and 115 kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., Section 92) approval is required for any alternatives to like-for-like.

The asset renewal assessment considers options for “right-sizing” the equipment such as:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment with lower ratings and built to current standards;
3. Replacing equipment with similar equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement); and
6. Replacing equipment with higher ratings and built to current standards.

Table 4: New Major HV Transmission Equipment Replacement Needs Identified in this NA

Station	Timing	Need Description
Strachan TS: Transformers T14 & T13/T15	2025* 2031	T14 requires replacement in the medium term with higher rated unit. T13/T15 need replacement in the medium term with higher rated units.
Basin TS: Transformers T3/T5	2027	T3/T5 require replacement in the near term with higher rated units.
Scarboro TS: Transformer T23	2027	T23 requires replacement in the near term with like-for-like unit.
Fairchild TS: Transformer T3/T4	2028	T3 requires replacement in the medium term with like-for-like unit.
Malvern TS: Transformer T3	2029	T3 requires replacement in the medium term with like-for-like unit.
Manby TS: Transformer T14	2029	T14 need replacement in the medium term with similar unit per current standard.
Duplex TS: Transformers T3/T4	2031	T3/T4 require replacement in the medium term with higher rated units.

* Need date is advanced to support planned work at the other DESN in Strachan TS.

The newly identified major HV transmission equipment replacement need in this NA will be discussed in detail in the following subsections. The previously identified asset renewal needs from the last RP cycle, for which project execution has not yet been initiated, will also be reviewed and discussed in the following. The TWG recommends continuation of addressing all the identified needs for the Toronto Region as per the recommended plan described in each subsection. THESL has also confirmed that there is no plan to replace any major HV transmission equipment under its under ownership over the study period.

For the 115-13.8 kV 45/75 MVA step-down transformers where replacement is required, and upsizing is recommended, the largest standard size (60/100MVA) units for this voltage class will be used. The 115-13.8 kV 60/100 MVA transformer has two secondary windings and each winding has an LTR of 72 MVA which matches the 3000 A or 72 MVA metal clad switchgear that THESL has standardized on and used at 13.8 kV. Even if a larger custom size transformer is procured, no additional station capacity will be provided as it is limited by the metal clad switchgear. The estimated incremental cost of upsizing a 45/75 MVA unit to a 60/100 MVA unit is approximately $300k based on current dollars.

7.1.1 Strachan TS

Strachan TS comprises two DESN units, T12/T14 (T12 replaced in 2022: 60/100 MVA; T14: 45/75 MVA) and T13/T15 (45/75 MVA), having a summer 10-Day LTR of 171 MW. The station's 2021 actual non-coincident summer peak load was about 135 MW and is forecasted to be approximately 140 MW (net adjusted for extreme weather) in 2031.

Transformer T14 is currently about 47 years old and requires replacement in the medium term based on asset condition assessment. It is planned to replace it with a 60/100MVA unit as the companion transformer T12 was recently replaced with a 60/100 MVA unit thereby increasing the station capacity. Transformers T13 and T15 are currently about 40 years old and will also require replacement in the medium term based on their condition. The station capacity will be further increased after they are replaced with 60/100 MVA units. This will provide the additional capacity required to support the transformers and switchgear replacement work planned for Strachan TS in the medium term and accommodate the long-term growth and development need anticipated in the area subsequent to the Ontario Line subway project. Replacing the transformers with similar size equipment is not recommended since upgrading later within the lifetime of the transformer due to eventual load growth will be significantly more costly. It should also be noted that increasing capacity, as opposed to maintaining it, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. With new T12 installed this year, replacing the remaining three transformers with 60/100 MVA units will provide an additional station capacity of approximately 98 MVA at Strachan TS.

Based on the above, the TWG recommends that transformers T14, T13 and T15 be replaced with 60/100MVA units. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2025 for T14 and 2031 for T13 and T15.

7.1.2 Charles TS

Charles TS comprises two DESN units, T1/T2 (60/100 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 211 MW. The station's 2021 actual non-coincident summer peak load was about 127 MW and is forecasted to be approximately 165 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 55 years old and require replacement based on asset condition assessment.

The load at Charles TS is forecasted to be almost 80% of its LTR in the medium term. The load at three of the closest stations, Bridgman TS, Cecil TS and Terauley TS, is also forecasted to be about 80%, 65%, and 80% in the medium term.

As discussed in the 2nd cycle NA, the TWG recommends that transformer T3 and T4 be replaced with 60/100MVA units because this is the most cost-effective option that addresses the replacement need and maintains reliable long-term supply to the existing and potential customers in the area. Hydro One and THESL are coordinating this replacement work and the planned in-service date is 2026.

7.1.3 Duplex TS

Duplex TS comprises two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The station's 2021 actual non-coincident summer peak load was about 88 MW and is forecasted to be approximately 112 MW (net adjusted for extreme weather) in 2031.

Transformers T1 and T2 are currently about 54 years old and require replacement in the near term based on asset condition assessment. As discussed in the second cycle NA, replacing T1/T2 with 60/100 MVA units is recommended to allow for effective planning for long-term electricity needs, reliability and system resiliency. The forecast developed in this NA reaffirms this recommendation as the load at Duplex TS and its nearby stations Bridgman TS and Glengrove TS are to be over 85%, 80% and 95% of their station LTR respectively in 2031.

Transformer T3 and T4 are currently about 46-48 years old and require replacement in the medium term based on asset condition assessment. With the same reasons discussed above and the growing demand in the area, the TWG recommends that these transformers be replaced with 60/100 MVA units.

Hydro One and THESL will coordinate the replacement plan for transformers T1/T2 and T3/T4. The current planned in-service dates are 2026 and 2031 respectively.

7.1.4 Basin TS

Basin TS comprises one DESN unit, T3/T5 (45/75 MVA), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 57 MW and is forecasted to be approximately 85 MW (net adjusted for extreme weather) in 2031.

Transformers T3 and T5 are currently about 39 years old and require replacement in the near term based on asset condition assessment. The load at Basin TS is forecasted to be over 95% of its station LTR in 2031.

The load at its nearby stations Carlaw TS, Gerrard TS and Esplanade TS is also forecasted to be over 70-85% of their station LTR by 2031.

The City of Toronto is planning to re-develop the East Harbour land which is located in the Lakeshore and Don Roadway area in the near and medium term, as well as the Port Lands area in the longer term. These areas may see additional load in the longer term, beyond what is currently forecast in this NA. The scale and timing of additional load will depend upon the City's plan. However, the City's current re-development plans may impact the continued operation of Basin TS and several high voltage lines in their current locations in the Port Lands area. If implemented, this would significantly impact both Hydro One infrastructure and THESL infrastructure within and outside of Basin TS. No potential sites for a replacement transformer station or high voltage line routes have been identified by the City at this time. Hydro One and THESL have requested the City to revise its plans to avoid the conflicts with Basin TS and high voltage lines, and joined others in a legal appeal of the City's land plans. In December 2020, the appeal was settled provided that all parties will continue to reassess different options with and without the relocation or reconfiguration of the electricity infrastructure in the Port Lands area. There is no update or change in status at this time, but Hydro One and THESL will provide updates to the TWG as information becomes available.

Based on asset condition assessment of the existing transformers at Basin TS, the TWG recommends that transformers T3/T5 be replaced with 60/100 MVA units to address the replacement need and avoid any extended forced outages due to potential failure of these existing transformers. This will also provide an additional station capacity of approximately 46 MVA at Basin TS to help accommodate expected load growth in this area. Hydro One and THESL coordinate the replacement work.

The TWG also recommends that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process because of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle and as discussed in Section 7.3.4 of this report.

7.1.5 Scarboro TS

Scarboro TS comprises two DESN units, T21/T22 (75/125 MVA) and T23/T24 (75/125 MVA), having a summer 10-Day LTR of 340 MW. The station's 2021 actual non-coincident summer peak load was about 217 MW and is forecasted to be approximately 257 MW (net adjusted for extreme weather) in 2031.

Transformer T23 is currently about 48 years old and require replacement in the near term based on asset condition assessment. The load at Scarboro TS is forecasted to be over 75% of its station LTR in 2031. Its nearby stations Warden TS is forecasted to exceed its station capacity in the near term and need relief by transferring load to Scarboro TS. The load at other closest stations Bermondsey TS and Ellesmere TS is also forecasted to be about 80% and 85% of their station LTR by 2031.

Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing T23 is not a viable option. Upgrading the transformer is also not an option since it is already at the maximum standard size.

The TWG has recommended that transformer T23 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for the transformer and the planned in-service date is 2027.

7.1.6 Fairchild TS

Fairchild TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 346 MW. The station's 2021 actual non-coincident summer peak load was about 216 MW and is forecasted to be approximately 243 MW (net adjusted for extreme weather) in 2031. Transformers T1 is 52 years old but was rebuilt 36 years ago. The companion DESN transformer T2 failed and was replaced under emergency in 2017 with a similar 75/125 MVA unit. Transformers T3 and T4 in the other DESN are 39 years old. Transformers T1, T3 and T4 require replacement in the medium term based on asset condition assessment.

The load at Fairchild TS is forecasted to be over 70% of its LTR in the medium term. The load at the two closest stations, Bathurst TS and Leslie TS, is also forecasted to be about 95% and 90% of their respective LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing the transformers at Fairchild TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations. Upgrading the transformers is also not an option since they are already at the maximum standard size.

Based on the above, the TWG recommends that transformers T1, T3 and T4 be replaced like-for-like. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2028.

7.1.7 Bermondsey TS

Bermondsey TS comprises two DESN units, T1/T2 (75/125MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 348 MW. The station's 2021 actual non-coincident summer peak load was about 153 MW and is forecasted to increase significantly in the near term due to new load customers in the area. The load is forecasted to be approximately 275 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 57 years old and require replacement in the near term based on asset condition assessment.

The load at Bermondsey TS is forecasted to be almost 80% of its LTR in the medium term. The load at the three closest stations, Scarboro TS, Warden TS, and Leaside TS is forecasted to be over 75%, 100%[1], and 67% respectively of their LTR's in the medium term.

As evaluated in the 2nd cycle RIP and reaffirmed in this NA, transformer T3 and T4 are to be replaced with similar type and size equipment as per current standard because this is the most cost effective option that addresses the replacement need and maintains reliable long-term supply to the customers in the area. The planned in-service date of this refurbishment work is 2029.

7.1.8 Malvern TS

Malvern TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 176 MW. The station's 2021 actual non-coincident summer peak load was about 110 MW and is forecasted to be approximately 119 MW (net adjusted for extreme weather) in 2031. Transformers T3 is currently 36 years old and requires replacement in the medium term based on asset condition assessment.

The load at Malvern TS is forecasted to be almost 70% of its LTR in the medium term. The load at the three closest stations, Agincourt TS, Cavanagh MTS, and Sheppard TS is forecasted to be over 60%, 90%, and 90% respectively of their LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing the transformer at Malvern TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations.

Based on the above, the TWG recommends that transformer T3 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for this transformer. The planned in-service date is 2029.

7.1.9 Manby TS

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

Three of the autotransformers, T7, T9, and T12, and two of the step-down transformers, T13 and T14, are close to 55 years old and require replacement in the medium term based on asset condition assessment. It is to be noted that T14 was not identified as a candidate for replacement in the previous RP cycle. The autotransformers continue to be critical to the load supply to the downtown and west Toronto area and will

[1] The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by transferring some load to Scarboro TS in the near/medium term.

be replaced with similar 250 MVA units, consistent with recommendations from previous RP cycle. The expected in-service date for the autotransformer replacement is 2030.

The total summer 10-Day LTR of the six step-down transformers is 226 MW. The station's 2021 actual non-coincident summer peak load was about 237 MW which exceeds the station capacity and will be relieved in the near and medium term by transferring load to the second DESN at Horner TS recently built. The total DESN load at Manby TS, after the load transfer, is forecasted to be approximately 204 MW (net adjusted for extreme weather) in 2031, i.e. over 90% of its LTR in the medium term. Therefore, the TWG recommends transformers T13 and T14 (56/93 MVA units, non-standard size) be replaced with the current standard size units (75/125 MVA units) to address the replacement need and maintain reliable long-term supply to the customers in the area. This will potentially increase the station LTR by approximately 60 MVA. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date of this refurbishment work is 2029.

Previously, the 230 kV oil breakers were considered as candidates for replacement. Since then, the condition of these breakers has been reviewed and based on this assessment, they are not required for replacement in the near or medium term. Hydro One will continue to monitor the condition of these breakers and coordinate the future replacement plan with the phase 2 work of the Richview TS x Manby TS 230 kV Corridor Upgrade project as described in Section 7.2.1 of this report. Updates will be provided to the TWG in the next RP cycle as required.

7.1.10 Leslie TS

Leslie TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 323 MW. The station's 2021 actual non-coincident summer peak load was about 221 MW and is forecasted to be approximately 249 MW (net adjusted for extreme weather) in 2031. Transformer T1 is currently about 59 years old and require replacement based on asset condition assessment. The companion DESN transformer T2 is currently 25 years old and does not require replacement in the near or medium term.

It should be noted that transformers T1 and T2 are non-standard units with dual LV voltages (230-27.6-13.8 kV 75/125 MVA units). The 13.8 kV load that are currently supplied from Leslie TS will be diminished and the 13.8 kV supply will not be needed from Leslie TS. Excluding the capacity for the 13.8kV winding, the total station LTR for the 27.6kV load is about 280 MW. The 27.6kV load at Leslie TS will be at almost 90% of its LTR in the medium term. The load at the three closest stations, Fairchild TS, Cavanagh MTS, and Agincourt TS, is also forecasted to be over 70%, 90%, and 60% respectively of their LTR's in the medium term. THESL is also anticipating additional new load connection in the longer term at Leslie TS and Agincourt TS.

Based on the above and consistent with the recommendation from the last NA, the TWG recommends that transformer T1 be replaced with a standard unit of same size without dual LV voltages (i.e. a 230-27.6-27.6 kV 75/125 MVA unit). Hydro One and THESL will coordinate the replacement plan for this transformer. When more capacity is required at Leslie TS, the companion transformer T2 can be replaced with the same

230-27.6-27.6 kV 75/125 MVA unit to provide an increase of approximately 70 MVA for the 27.6 kV supply capacity. The planned in-service date for transformer T1 is 2030.

7.1.11 Overhead Transmission Line H1L/H3L/H6LC/H8LC

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. (about 2 route km) are required to be replaced in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2025.

7.1.12 Overhead Transmission Line L9C/L12C

The 115 kV circuits L9C/L12C provide connections between Leaside TS and Cecil TS, and supply to central downtown area including Charles TS and Cecil TS. The overhead section of this 115 kV double-circuit line between Leaside TS and Balfour Jct. (about 3.6 route km) is over 90 years old and require replacement in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2027.

7.2 Station and Transmission Capacity Needs in the Near / Medium Term

The Station and Transmission supply capacities have been reviewed. No near or medium-term station capacity need has been identified in the Toronto region. However, two transmission line capacity needs are identified below during the study period of 2022 to 2031.

7.2.1 Richview TS x Manby TS 230 kV Corridor – Line Capacity

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The need and options to increase transfer capability of this transmission corridor to support the continuous load growth in these areas has been identified and discussed in the past RP cycles. This need was also reaffirmed in an IRRP addendum done in 2021.[2]

[2] The IRRP addendum for the Richview TS x Manby TS Circuit Upgrade need has not been published or shared outside of the TWG yet. However, since it was just reviewed last year, this need is not to be re-evaluated in this NA.

As previously documented, the recommendation is to proceed with:

Phase 1: Rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits" R2K and R15K. This configuration avoids the need to build new terminations and new breakers at Manby TS. This project is currently in estimate and public consultation phase. The planned in-service date is 2026.

Phase 2: Unbundling the "supercircuits" with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS 230kV breakers replacement work when the time comes. As discussed in Section 7.1.9 of this report, the 230 kV breakers at Manby TS are currently in good condition and not planned to be in replaced in the coming 10 years. Their condition will be monitored and this phase 2 work will be coordinated with the replacement work. Updates will be provided to the TWG in the next RP cycle as required.

7.2.2 Manby TS x Riverside Junction 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Manby TS and John TS comprises four circuits K13J, K14J, K6J and H2JK, and provides supply to Downtown Toronto via three transformer stations John TS, Strachan TS and Copeland MTS. The 2021 actual total coincident summer peak load of these stations was about 370 MW and is forecasted to be approximately 513 MW and 500 MW (net adjusted for extreme weather) in 2026 and 2031 respectively. This corridor also provides backup supply to other stations that are normally connected to the Leaside / Hearn subsystem, such as Esplanade TS and Terauley TS.

The 7 km overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct., as shown in Figure 3, is potentially overloaded under the contingency of the loss of the other circuits on this corridor. This need was identified as a long-term need (2030-2035) in the previous RIP. However, the new forecast in this NA has reflected the load demand increase from the Ontario Line subway and other residential and commercial development projects expected in the near term at Copeland MTS and John TS, and therefore this need is advanced to 2026.

The companion overhead line K6J/H2JK was upgraded in 2000 and currently has a higher ampacity rating than the K13J/K14J line. The capacity of this corridor could potentially be increased by approximately 100 MVA if the overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct. is upgraded. A line upgrade project of this scope may take over 5-6 years to carry out the required work before it is in-service which includes, but not limited to, the development and estimate work, public consultation, environmental assessment, internal and external approvals, construction, outage planning and commissioning work. The earliest in-service date of the reconductoring work could be in 2028 if the development and estimate work is to begin in 2023. It is also to be noted that extended outages may be required to reconductor the line. As a result of limited load transfer capability between the Manby West and Leaside / Hearn subsystems, obtaining the said outages to complete this work could be very challenging, and worsen further as the load increases in these areas.

Considering the long timeline of the corridor upgrade and that more load could potentially be affected during construction, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers. This need will continue to be reviewed as part of the next phase of this RP cycle.

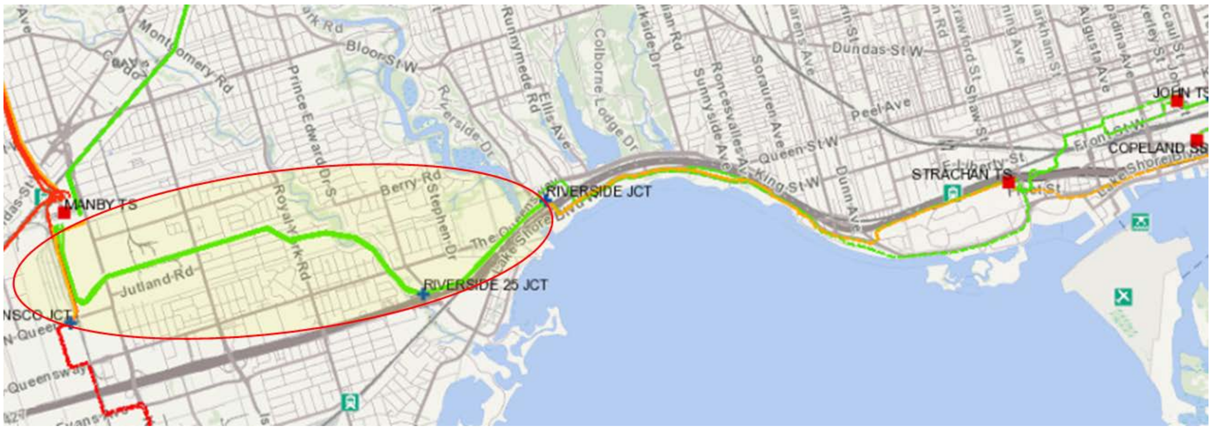

Figure 3: 115 kV Corridor between Manby TS and John TS (overhead section is circled)

7.3 Long-Term Capacity Needs

This section describes the long-term capacity needs identified from the previous RIP as well as the potential ones that are observed from this NA review.

This NA focuses on assessing and identifying the needs in the Toronto Region within the 10-year timeframe (up to 2031). It is observed that there are some transformer stations and 230 kV circuits that are approaching their limits by 2031 as listed in Table 5 below. This finding is consistent with the information shared by the TWG that the Toronto Region is about to embark on a period of growth over the short and medium term driven by electrification, and that the large-scale development and customer connection projects are expected in several areas within the Toronto Region in the coming years.

Table 5: Potential Long-Term Capacity Needs to be Further Assessed

Station / Circuit	Need Description
Glengrove TS	Total net demand is forecasted to be about 98% of station LTR by 2031.
Finch TS / Bathurst TS	Total net demand at Finch TS and Bathurst TS is forecasted to be about 100% and 97% of station LTR respectively by 2031.
Warden TS	The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by load transfer to Scarboro TS in the near/medium term.
Parkway TS to Richview TS 230 kV Corridor (P21R/P22R)	Markham #1 Jct. x Leaside Jct. section of the overhead 230 kV circuits P21R and P22R, connecting Parkway TS and Richview TS, is approaching limit by 2031.

These potential long-term capacity needs will be further reviewed in the next phases of this RP cycle.

7.3.1 Fairbank TS – Station Capacity

The long-term capacity need at Fairbank TS was identified in the previous RIP. The load at Fairbank TS was expected to exceed LTR within the 2030-2035 time period.

Fairbank TS comprises two DESN units, T1/T3 and T2/T4 (all 115/27.6 kV 50/83 MVA units), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 197 MW. The excess load is planned to be transferred to Runnymede TS where a new DESN was built in 2019 and the old DESN was rebuilt in 2021. The Fairbank TS load is forecasted to be approximately 170 MW (net adjusted for extreme weather) or 93% of its station LTR in 2031. The transformer replacement work at Fairbank TS (T1/T2/T3/T4) is also underway with planned in-service date of 2024. The station LTR at Fairbank TS is expected to increase after the transformer replacement and provide some additional capacity. Together with the new and refurbished DESNs recently built at Runnymede TS, it is expected that the existing facilities will be adequate to supply the long-term growth in the area. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.2 Sheppard TS – Station Capacity

The long-term capacity need at Sheppard TS was identified in the previous RIP. The load at Sheppard TS was expected to exceed LTR within the 2030-2035 time period.

Sheppard TS comprises two DESN units, T1/T2 (75/125 MVA units with idle winding) and T5/T6 (50/83 MVA units), having a summer 10-Day LTR of 204 MW. The station's 2021 actual non-coincident summer peak load was about 167 MW, and is forecasted to be approximately 187 MW (net adjusted for extreme weather) or 92% of its station LTR in 2031. Consideration may be given to utilizing the idle winding on transformers T1/T2. The TWG recommends the Sheppard TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.3 Strachan TS – Station Capacity

The long-term capacity need at Strachan TS was identified in the previous RIP. The load at Strachan TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.1, the transformer T12 at Strachan TS has been replaced recently with a 60/100 MVA unit. The station capacity at Strachan TS will increase after the transformer T14, and T13/T15 are also replaced with 60/100MVA units. This will provide adequate capacity to accommodate the long-term growth. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.4 Basin TS – Station Capacity

The long-term capacity need at Basin TS was identified in the previous RIP. The load at Basin TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.4, the load at Basin TS is forecasted to be over 95% in 2031 and expected to increase further in the longer term due to the development plan in the Port Lands area as well as the East Harbor area. The transformers T13/T15 (45/75 MVA units) require replacement in the near term based on asset condition assessment. The TWG recommends that Hydro One and THESL coordinate and initiate the development work for replacing the transformers T3/T5 with 60/100 MVA units, and that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process. This will include consideration of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle.

7.3.5 Glengrove TS – Station Capacity

Glengrove TS comprises two DESN units, T1/T3 and T2/T4 (all 25/42 MVA units), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 47 MW and is forecasted to be approximately 86 MW (net adjusted for extreme weather) or 98% of its LTR in 2031.

As discussed in Section 7.1.3, its closet station Duplex TS also has two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The load at Duplex TS is forecasted to be approximately 112 MW (net adjusted for extreme weather) or 88% of its LTR in 2031. The transformers T1/T2 and T3/T4 require replacement in the near and medium term. The TWG has recommended that these transformers be replaced with 60/100 MVA units to provide additional capacity in this area, and that the Glengrove TS and Duplex TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.6 Finch TS / Bathurst TS – Station Capacity

THESL has identified an emerging load growth in the Northwest Toronto area near Finch TS and Bathurst TS due to re-development plan in the Downsview area located in the Keele and Sheppard area.

Finch TS comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 366 MW. The station's 2021 actual non-coincident summer peak load was about 253 MW and is forecasted to be approximately 367 MW (net adjusted for extreme weather) in 2031.

Bathurst TS also comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 361 MW. The station's 2021 actual non-coincident summer peak load was about 241 MW and is forecasted to be approximately 350 MW (net adjusted for extreme weather) or 97% of its LTR in 2031. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.7 Warden TS – Station Capacity

Warden TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 150 MW and is forecasted to be approximately 195 MW and 185 MW (net adjusted for extreme weather) in 2024 and 2031.

The demand at Warden TS exceeds its station LTR in 2024 due to new large customer connection request in the south Toronto. THESL will manage it in the near/medium term by transferring load to its closest station Scarboro TS as discussed in Section 7.1.5. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.8 Manby W TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Manby West TS was identified in the previous RIP. Manby West TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. This NA also affirms this transformation capacity need and the autotransformer replacement plan for T12 that is expected to provide relief to this constraint as discussed in Section 7.1.9. The current planned in-service date of the T12 autotransformer replacement is around 2030. The TWG recommends that the long-term supply need in this area be reviewed as part of the next phase of this RP cycle.

7.3.9 Leaside TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Leaside TS was identified in the previous RIP. Leaside TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T16 in the fleet, and is potentially overloaded within the 2035-2040 time period, following T15 or T17 contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

7.3.10 Parkway TS to Richview TS 230 kV Corridor – Line Capacity

The 230 kV circuits P21R/P22R provide the transmission network connection between Parkway TS and Richview TS. These circuits also supply two transformer stations in the City of Markham as well as three transformer stations in the Northwest Toronto area (Leslie TS, Bathurst TS, and Finch TS) together with the other 230 kV circuits on the “Finch Corridor” between Cherrywood TS and Richview TS.

With the increasing demand forecasted on this corridor, some sections of the circuits P21R/P22R[3] are over 90% of their ratings under certain contingencies in the medium term and are potentially overloaded in the long term. Consideration may be given to reconductoring part of the circuits close to the Parkway TS end. It is to be noted that the baseline NA forecast does not reflect a number of customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may become sooner. The TWG recommends this need be monitored and reviewed in the next phase of this RP cycle.

[3] The line section between Markham #1 Jct. and CTS Jct. of the circuits P21R/P22R is found to be the most restrictive in this NA review; however, the scope and timing of the preferred plan for this need will be reviewed and determined in the next phases of this RP cycle when a more certain and longer term load forecast will become available and considered.

7.3.11 Leaside TS to Wiltshire TS 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Leaside TS and Wiltshire TS comprises four circuits L13W, L14W, L18W and L15. It provides supply to Midtown Toronto area via two transformer stations Bridgman TS and Dufferin TS. The 2021 actual total coincident summer peak load of these stations was about 257 MW and is forecasted to be approximately 280 MW (net adjusted for extreme weather) in 2031. This corridor also provides backup supply to other stations that are normally connected to the Manby East subsystem such as Wiltshire TS, Fairbank TS and/or Runnymede TS.

The line capacity need on this corridor was identified as a long-term need (2035-2040) in the previous RIP, that the 1.8 km underground section of the circuit L15 between Bayview Jct. and Balfour Jct. is potentially overloaded in the long term. In this NA review, the contingency flow on this line section is about 80% of its limited time emergency rating in 2031. The TWG recommends the loading and the line capacity need on this Leaside TS x Wiltshire TS corridor be monitored and reviewed in the next phase of this RP cycle.

7.4 Load Restoration Analysis

The contingencies from the previous load restoration analysis in the 2nd cycle IRRP are reviewed along with this new NA forecast. The potential load interrupted by configuration for the following contingencies is significantly higher than the amount from the 2nd cycle IRRP.

For the loss of 230kV circuits C14L and C17L[4] (stations connected are Warden TS and Bermondsey TS), a total load of 379 MW in 2031 will be interrupted by configuration and 129 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

For the loss of 230kV circuits C18R and P22R[5] (Bathurst TS), a total load of 350 MW in 2031 will be interrupted by configuration and 100 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

THESL has indicated that the current distribution feeder configuration and spare capacity from the nearby stations will not be adequate to resupply all of the aforementioned amount of load in excess of 250 MW within 30 minutes and recommends that these load restoration scenarios and options be reviewed in the next phase of this RP cycle.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended

[4] The circuits C14L and C17L only share the same towers along a 4 km overhead line tap supplying Warden TS.
[5] The circuits C18R and P22R only share the same towers along a 2 km overhead line tap supplying Bathurst TS.

investments. The TWG has determined that the key electric demand driver in the Toronto Region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and electrified heating.[6]

A high demand growth forecast was developed by applying + 5% on the extreme summer corrected Normal Growth net load forecast. The TWG has also considered a slower EV and electrified heating change and developed a low demand growth forecast by applying - 2.5% on the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Section 7 is summarized in Table 6.

Table 6: Impact of Sensitivity Analysis on the Identified Capacity Needs

Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario (1)
Manby TS to Riverside Jct 115 kV Corridor	2026	2026	2026
Fairbank TS	Beyond 2031	Beyond 2031	-
Sheppard TS	Beyond 2031	Beyond 2031	-
Strachan TS	Beyond 2031	Beyond 2031	-
Basin TS	Beyond 2031	2031	-
Glengrove TS	Beyond 2031	2031	-
Finch TS / Bathurst TS	Beyond 2031	2028	-
Warden TS	Beyond 2031	TBD (2)	-
Manby W TS Autotransformers (T12)	Beyond 2031	Beyond 2031	-
Leaside TS Autotransformers (T16)	Beyond 2031	2031	-
230 kV Parkway TS to Richview TS Corridor	Beyond 2031	Beyond 2031 (3)	-
115 kV Leaside TS to Wiltshire TS Corridor	Beyond 2031	Beyond 2031	-

(1) The objective of a low growth scenario analysis is to identify any deferment in the timing of needs identified in this NA. Therefore, the long-term needs will not be looked at in the low growth scenario analysis.
(2) Forecasted load demand at Warden TS exceeds its capacity from 2024 but THESL plans to manage it by transferring the excess load to Scarboro TS. A higher load growth scenario will certainly advance the need to relieve Warden TS and further assessment will be carried out during the next phases of this Regional Planning cycle.
(3) Like the normal growth scenario, the high growth scenario does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may be advanced to the medium term. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

In the high growth scenario, the timing of some of the long-term station capacity needs (Basin TS, Glengrove TS, Finch TS / Bathurst TS, and potentially Warden TS as well) is advanced to the medium-term timeframe. The timing of the long-term transformation capacity needs at Leaside TS is also advanced to 2031. The TWG recommends these needs be assessed during the next phases of this RP cycle.

The timing of the near-term capacity need on the 115 kV corridor between Manby TS and Riverside Jct. does not change in the sensitivity analysis. As discussed in Section 7.2.2, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers and this need be reviewed as part of the next phase of this RP cycle.

[6] The sensitivity analysis does not consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated in this report, and will be assessed in the next phase of this RP cycle.

9 RECOMMENDATIONS

The TWG's recommendations to address the needs identified are as follows:

a) No further regional coordination is required for the following need:
- Asset renewal needs for replacing the major HV equipment as listed in Table 7 below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
- The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
- The load restoration and long-term needs as listed in the following table.

Table 7 summarizes the above recommendations.

Table 7: Summary of Recommendations

<table>
<tr><th>Further Regional Coordination Not Required</th><th>Further Regional Coordination Required</th></tr>
<tr><td rowspan="2">Asset Renewal Needs (Stations):
• Strachan T14 & T13/T15
• Charles TS: T3/T4
• Duplex TS: T1/T2 & T3/T4
• Basin TS: T3/T5
• Scarboro TS: T23
• Fairchild TS: T1 & T3/T4
• Bermondsey TS: T3/T4
• Malvern TS: T3
• Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer
• Leslie TS: T1

Asset Renewal Needs (Lines):
• 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section
• 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section

Line Capacity Need:
• 230 kV Richview TS to Manby TS Corridor

Station Capacity Need:
• Fairbank TS
• Strachan TS</td><td>Line Capacity Need:
• 115 kV Manby TS to Riverside Jct. Corridor

Load Restoration:
• Loss of C14L/C17L
• Loss of C18R/P22R</td></tr>
<tr><td>Long-Term Needs:
• Sheppard TS – Station Capacity
• Basin TS – Station Capacity
• Glengrove TS – Station Capacity
• Finch TS / Bathurst TS – Station Capacity
• Warden TS – Station Capacity
• 230/115kV Manby W Autotransformers – Transformation Capacity
• 230/115kV Leaside TS Autotransformers – Transformation Capacity
• 230 kV Parkway TS to Richview TS Corridor – Line Capacity
• 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity</td></tr>
</table>

This NA assessment was performed before the publication of the IESO's "Pathways to Decarbonization" report on December 15, 2022, and does not include its impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region. The TWG recommends that the "Pathways to Decarbonization" and its subsequent impact be considered and assessed in the next phase of this RP cycle.

10 REFERENCES

[1]. Hydro One, "Toronto Regional Infrastructure Plan", March 6, 2020.
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Toronto%20Regional%20Infrastructure%20Plan_Mar6%202020.pdf

[2]. Hydro One, "Needs Assessment Report, Toronto Region", October 18, 2017.
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[3]. IESO, "Toronto Region: Integrated Regional Resource Plan", August 9, 2019.
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto-IRRP-20190809-Report.pdf

[4]. Planning Process Working Group Report to the Board, 17 May 2013.
http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPTECHNICAL STUDY TEAM_Regional_Planning_Report_to_the_Board_App.pdf

[5]. IESO, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0, August 22, 2007
https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.ashx

Appendix A-1: Non-Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1249**	**1317**	**1388**	**1459**	**1483**	**1513**	**1525**	**1553**	**1573**	**1575**	**1577**
Agincourt TS	T5/T6	174	88	89	91	98	102	105	106	106	108	108	108
Bathurst TS	T1/T2	183	131	120	123	125	142	160	178	176	175	174	172
	T3/T4	178	110	135	131	146	148	146	146	163	181	179	178
Cavanagh MTS	T1/T2	157	120	117	118	121	121	127	130	141	141	141	142
Fairchild TS	T1/T2	174	108	119	131	134	134	134	134	133	132	132	132
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	129	144	167	176	178	181	182	182	183	184	185
	T3/T4	186	124	132	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	9	13	14	13	10	11	0	0	0	0	0
	T1/T2 27.6	96	85	86	92	100	102	88	91	91	92	93	93
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	110	106	108	108	109	112	112	113	114	115	119
EAST 230kV		**1475**	**962**	**1018**	**1059**	**1154**	**1156**	**1158**	**1186**	**1207**	**1209**	**1212**	**1213**
Bermondsey TS	T1/T2	186	60	75	103	109	109	127	143	142	142	141	140
	T3/T4	162	93	120	124	129	132	113	131	130	129	132	135
Ellesmere TS	T3/T4	189	124	123	131	152	157	157	156	165	165	164	163
Leaside TS	T19/T20/T21 13.8	100	67	70	70	69	70	71	71	71	71	71	71
	T19/T20/T21 27.6	110	83	81	80	78	78	77	76	75	75	74	74
Scarboro TS	T21/T22	189	109	113	111	137	139	138	136	150	150	151	150
	T23/T24	151	108	112	111	112	109	108	108	108	108	108	107
Sheppard TS	T1/T2	95	76	69	70	70	70	70	70	70	81	81	82
	T5/T6 (was T3/T4)	109	91	98	100	103	105	106	108	109	103	104	105
Warden TS	T3/T4	182	150	156	160	195	187	191	188	186	186	186	185
WEST 230kV		**1239**	**768**	**752**	**796**	**837**	**810**	**828**	**864**	**862**	**870**	**879**	**889**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	147	126	147	145	145	117	115	115	114	114	113
Manby TS	T13/T14	106	85	81	82	98	98	83	83	84	84	86	86
	T3/T4	60	73	58	58	59	60	53	53	53	55	56	58
	T5/T6	60	79	64	66	65	53	55	56	57	59	59	61
Rexdale TS	T1/T2	187	102	104	108	108	93	93	140	144	148	154	160
Richview TS	T1/T2	159	111	114	112	111	109	108	106	105	104	103	102
	T5/T6	188	103	104	121	142	141	150	140	132	132	132	133
	T7/T8	113	68	70	71	71	72	74	76	77	79	80	81
LEASIDE 115kV		**1779**	**1141**	**1265**	**1318**	**1339**	**1365**	**1365**	**1369**	**1382**	**1389**	**1403**	**1416**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	147	147	147	147	147	148	150
Carlaw TS	T1/T2	73	63	43	43	42	47	49	50	51	52	53	53
Cecil TS	T1/T2	85	55	61	60	59	58	57	55	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	81	81	82
Charles TS	T1/T2	130	70	86	91	95	93	98	97	98	97	96	95
	T3/T4	81	57	62	64	60	71	71	72	71	70	70	70
Dufferin TS	T1/T3	94	46	53	64	59	63	65	66	66	67	67	67
	T2/T4	86	80	71	70	68	69	68	66	66	65	65	65
Duplex TS	T1/T2	81	55	66	68	70	70	72	73	73	75	76	78
	T3/T4	47	35	36	33	32	32	33	33	33	33	33	34
Esplanade TS	T11/T12/T13	187	125	145	150	155	157	156	155	157	158	158	158
Gerrard TS	T1/T2	128	30	55	78	80	79	80	80	84	88	91	91
Glengrove TS	T1/T3	44	17	31	33	35	35	35	35	36	36	37	37
	T2/T4	44	30	32	36	39	39	41	42	44	46	47	49
Main TS	T3/T4	77	56	60	62	62	63	63	64	64	65	66	67
Terauley TS	T1/T4	108	53	61	91	95	99	85	85	87	87	88	89
	T2/T3	108	88	92	81	86	86	88	88	88	88	88	89
MANBY E 115kV		**579**	**362**	**374**	**399**	**421**	**428**	**430**	**428**	**429**	**430**	**432**	**436**
Fairbank TS	T2/T4	90	90	96	86	89	90	91	88	89	89	90	91
	T1/T3 (to be T5/T6)	92	107	89	81	74	74	75	75	76	77	78	79
Runnymede TS	T1/T2	108	78	80	95	108	110	106	105	104	103	103	102
	T5/T6 (was T3/T4)	111	32	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	25	34	34	34	34	35	35	35	35	36	36
	T7X/T2X	129	30	47	59	67	67	66	65	65	64	64	64
MANBY W 115kV		**611**	**374**	**375**	**380**	**423**	**425**	**518**	**516**	**511**	**508**	**506**	**505**
Copeland MTS	T1/T3	130	80	104	114	120	121	182	179	177	175	174	173
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	141	140
	T5/T6	123	75	92	92	99	99	101	101	54	53	53	52
Strachan TS	T12/T14	74	52	59	56	57	57	87	86	86	86	86	87
	T13/T15	97	84	81	81	86	89	50	50	51	52	52	53
TOTAL REGIONAL LOAD		**7586**	**4856**	**5100**	**5341**	**5633**	**5667**	**5812**	**5887**	**5944**	**5979**	**6008**	**6036**

Appendix A-2: Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1173**	**1240**	**1309**	**1376**	**1401**	**1430**	**1444**	**1470**	**1490**	**1492**	**1493**
Agincourt TS	T5/T6	174	72	73	74	80	83	86	86	87	88	89	88
Bathurst TS	T1/T2	183	127	116	119	121	138	156	173	171	170	169	168
	T3/T4	178	110	135	131	146	148	146	145	163	180	179	178
Cavanagh MTS	T1/T2	157	96	93	94	97	97	101	104	113	113	113	113
Fairchild TS	T1/T2	174	106	117	129	132	132	132	131	131	130	130	129
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	128	143	166	175	177	180	180	181	181	182	183
	T3/T4	186	124	133	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	5	7	8	7	6	6	0	0	0	0	0
	T1/T2 27.6	96	74	75	80	87	89	76	79	80	80	81	81
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	96	92	94	94	95	97	98	98	99	100	104
EAST 230kV		**1475**	**865**	**915**	**950**	**1029**	**1033**	**1031**	**1056**	**1075**	**1076**	**1079**	**1080**
Bermondsey TS	T1/T2	186	48	60	82	87	87	101	114	113	113	113	112
	T3/T4	162	88	114	117	122	125	107	124	123	122	125	128
Ellesmere TS	T3/T4	189	116	115	122	141	147	146	145	154	154	153	152
Leaside TS	T19/T20/T21 13.8	100	66	69	69	68	69	70	70	70	70	70	70
	T19/T20/T21 27.6	110	79	77	76	74	74	73	72	72	71	71	70
Scarboro TS	T21/T22	189	94	97	96	118	119	118	117	129	129	129	129
	T23/T24	151	107	111	110	111	109	108	107	108	107	107	107
Sheppard TS	T1/T2	95	65	60	60	60	60	60	60	60	69	70	70
	T5/T6 (was T3/T4)	109	89	96	97	100	102	104	105	106	101	102	103
Warden TS	T3/T4	182	113	118	120	147	141	144	141	140	140	140	140
WEST 230kV		**1239**	**648**	**640**	**680**	**711**	**685**	**710**	**745**	**743**	**749**	**756**	**764**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	144	123	144	142	142	115	112	112	112	111	111
Manby TS	T13/T14	106	58	55	56	67	67	57	57	57	57	59	58
	T3/T4	60	36	29	29	29	30	26	26	26	27	28	29
	T5/T6	60	75	60	62	62	50	52	53	54	56	55	57
Rexdale TS	T1/T2	187	97	99	103	102	89	88	133	137	141	147	152
Richview TS	T1/T2	159	109	112	110	108	107	106	104	103	102	101	100
	T5/T6	188	83	84	98	114	114	121	113	106	106	107	107
	T7/T8	113	46	47	48	48	49	50	51	53	54	54	55
LEASIDE 115kV		**1779**	**1131**	**1253**	**1305**	**1326**	**1352**	**1351**	**1355**	**1368**	**1375**	**1389**	**1401**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	148	147	147	147	147	149	151
Carlaw TS	T1/T2	73	62	43	42	41	46	49	49	50	51	52	52
Cecil TS	T1/T2	85	55	61	61	59	58	57	56	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	80	81	82
Charles TS	T1/T2	130	70	86	91	94	93	97	97	97	96	95	94
	T3/T4	81	57	61	64	60	70	71	71	70	70	70	70
Dufferin TS	T1/T3	94	46	53	63	58	63	64	65	66	66	66	66
	T2/T4	86	78	69	68	66	67	66	65	64	64	63	63
Duplex TS	T1/T2	81	55	67	68	70	71	72	73	74	75	76	78
	T3/T4	47	34	35	33	31	31	32	32	32	32	33	33
Esplanade TS	T11/T12/T13	187	125	145	150	155	156	156	155	157	157	157	158
Gerrard TS	T1/T2	128	29	53	76	77	77	77	77	81	85	88	88
Glengrove TS	T1/T3	44	16	30	32	34	34	34	34	34	35	35	36
	T2/T4	44	29	31	35	37	38	40	41	43	44	45	47
Main TS	T3/T4	77	54	58	60	61	61	62	62	62	63	64	65
Terauley TS	T1/T4	108	52	60	89	94	97	83	84	85	86	87	88
	T2/T3	108	87	91	80	85	85	87	87	87	87	88	88
MANBY E 115kV		**579**	**293**	**336**	**362**	**384**	**390**	**392**	**390**	**391**	**392**	**394**	**398**
Fairbank TS	T2/T4	90	79	84	75	78	79	80	77	78	78	79	80
	T1/T3 (to be T5/T6)	92	91	75	69	62	63	63	64	64	65	66	67
Runnymede TS	T1/T2	108	69	71	83	95	97	94	93	92	91	90	90
	T5/T6 (was T3/T4)	111	1	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	23	32	32	32	32	33	33	33	33	34	34
	T7X/T2X	129	30	46	59	66	66	65	65	64	64	64	63
MANBY W 115kV		**611**	**370**	**371**	**376**	**418**	**420**	**512**	**510**	**506**	**503**	**501**	**500**
Copeland MTS	T1/T3	130	79	102	112	119	119	180	177	175	173	171	170
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	140	140
	T5/T6	123	74	91	91	98	98	100	99	53	53	52	52
Strachan TS	T12/T14	74	51	58	56	56	56	85	85	85	85	85	85
	T13/T15	97	83	80	80	85	88	49	50	50	51	52	53
TOTAL REGIONAL LOAD		**7586**	**4480**	**4756**	**4982**	**5245**	**5281**	**5426**	**5500**	**5553**	**5585**	**5611**	**5636**

Appendix B: Lists of Step-Down Transformer Stations (Current)

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L14W/L15/L18W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Copeland MTS T1/T3	115/13.8	D11J/D12J
Dufferin TS T1/T3	115/13.8	L13W/L18W
Dufferin TS T2/T4	115/13.8	L13W/L18W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10DE(C5E)/H9DE(C7E)
Fairbank TS T1/T3 (to be T5/T6)	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T2	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
Horner TS T1/T2	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	Leaside Buses HL2, HL3, HL16
Leaside TS T19/T20/T21 27.6	230/27.6	Leaside Buses HL2, HL3, HL16
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4 27.6	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1

Station (DESN)	Voltage (kV)	Supply Circuits
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T1/T2	115/27.6	K12W/K11W
Runnymede TS T5/T6 (was T3/T4)	115/27.6	K12W/K11W
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T5/T6 (was T3/T4)	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T7X/T2X	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)

Appendix C: Lists of Transmission Circuits

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RP	Regional Planning
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Toronto

REGIONAL INFRASTRUCTURE PLAN

March 6, 2020

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Prepared and supported by:

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Toronto Hydro-Electric System Limited
Hydro One Networks Inc. (Lead Transmitter)

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE TORONTO REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities ("Alectra")
- Elexicon Energy Inc. ("Elexicon")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Toronto Hydro-Electric System Limited ("THESL")
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of Toronto regional planning process, which follows the completion of the Toronto Integrated Regional Resource Plan ("IRRP") in August 2019 and the Toronto Region Needs Assessment ("NA") in October 2017. This RIP provides a consolidated summary of the needs and recommended plans for Toronto Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Midtown Transmission Reinforcement Project (completed in 2016)
- Clare R. Copeland 115 kV Switching Station and Copeland MTS (completed in 2019)
- Manby SPS Load Rejection (L/R) Scheme (completion in 2019)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/ H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE TORONTO REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, Alectra Utilities ("Alectra"), Elexicon Energy Inc. ("Elexicon"), Hydro One Networks Inc. (Distribution), the Independent Electricity System Operator ("IESO"), and Toronto Hydro-Electric System Limited ("THESL") in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Toronto Region is comprised of the area within the municipal boundary of the City of Toronto. Electrical supply to the region is provided by thirty-five 230 kV and 115 kV step-down transformer stations ("TS") as shown in Figure 1-1. The outer parts of the region to the east, north, and west are supplied by fifteen 230/27.6 kV and two 230/27.6-13.8 kV step-down transformer stations. The central area is supplied by two 230/115 kV autotransformer stations at Leaside TS and Manby TS, and sixteen 115/13.8 kV and two 115/27.6 kV step-down transformer stations.

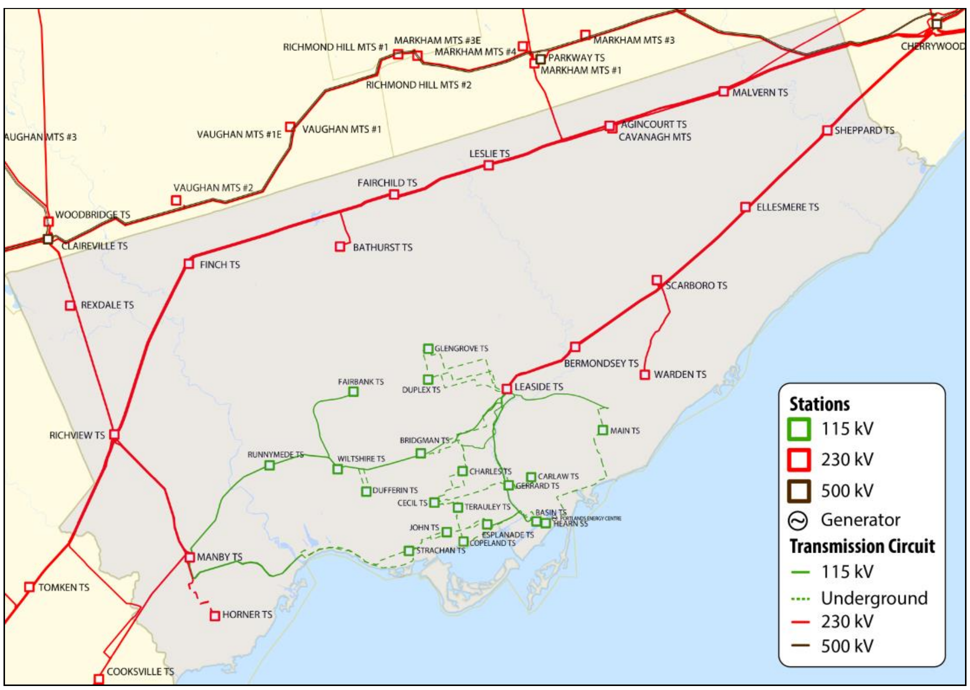


Figure 1-1: Toronto Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the Toronto Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;

- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

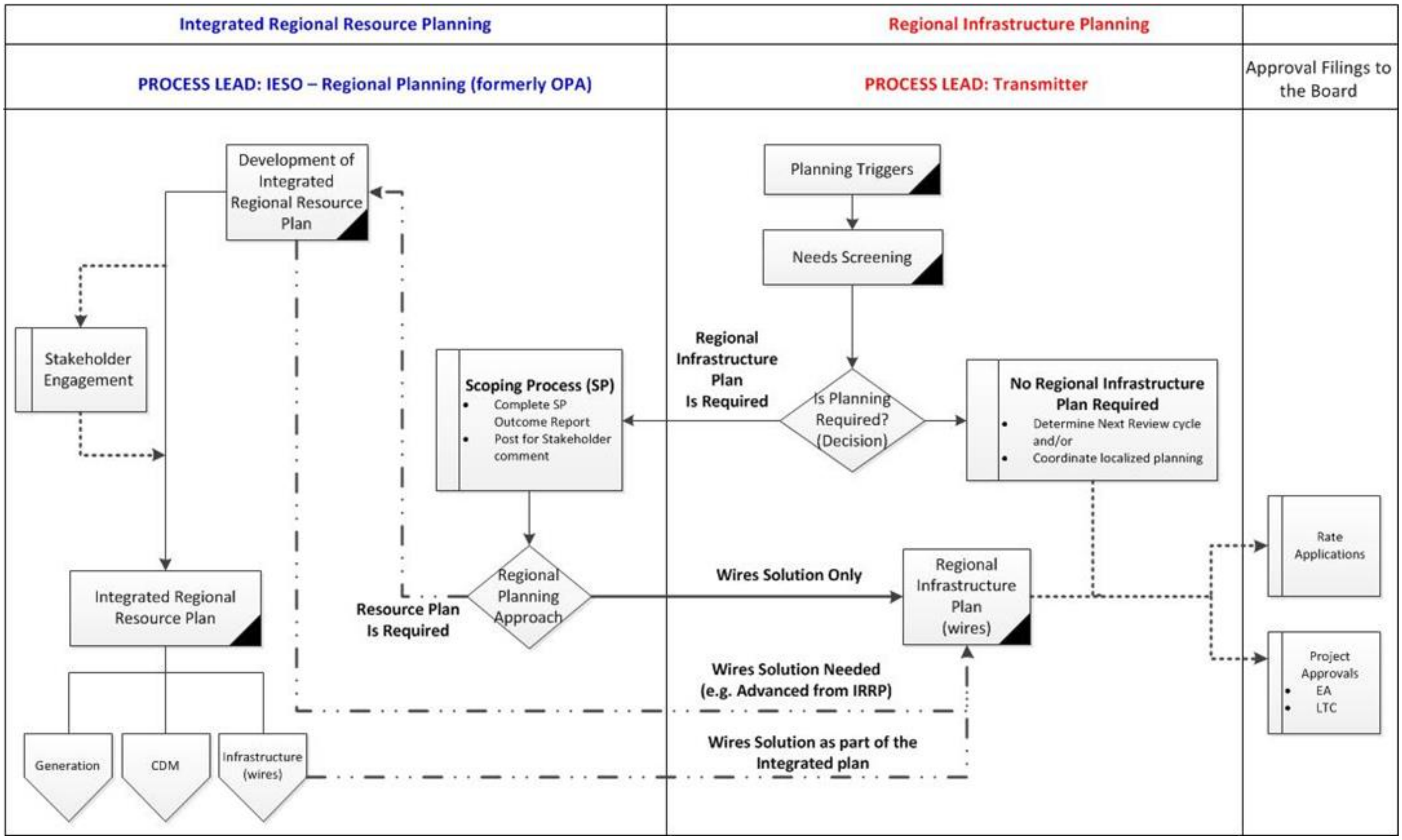


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

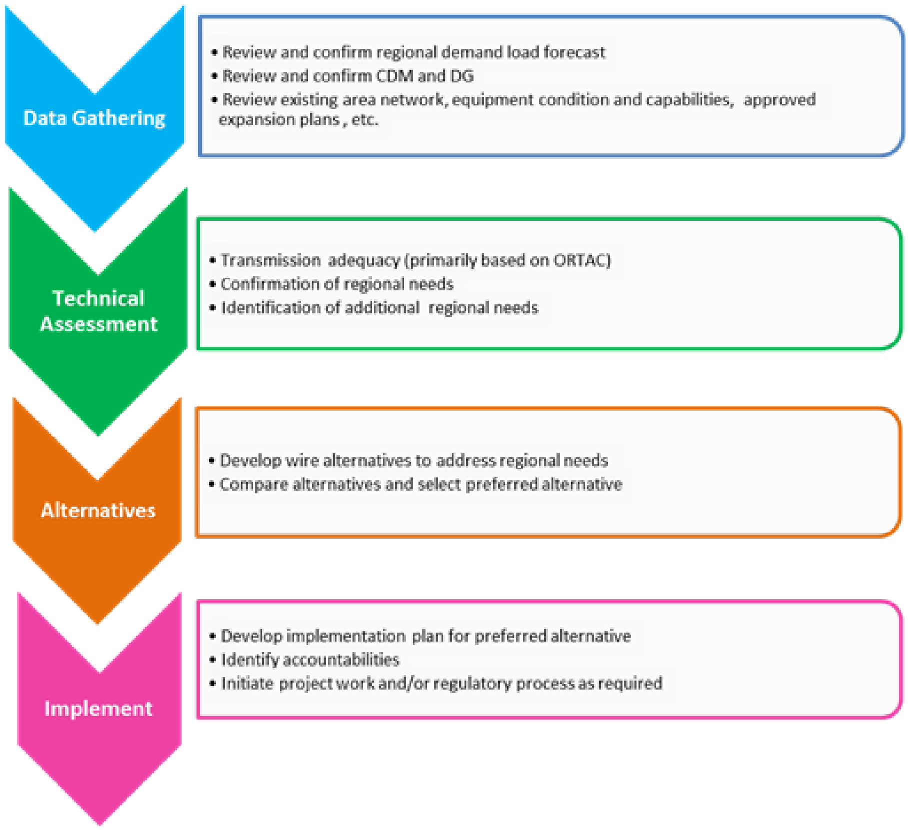


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST, AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Toronto Region is provided through three 500/230 kV transformers stations at Claireville TS, Cherrywood TS, and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near the Downtown area and connected to the 115 kV network at Hearn Switching Station (“SS”). The Toronto Region summer coincident peak demand in 2018 was about 4,660 MW which represents about 20% of the gross total demand (23240 MW) in the province.

Toronto Hydro-Electric System Limited (“THESL”) is the main Local Distribution Company (“LDC”) which serves the electricity demand in the Toronto Region. Other LDCs supplied from electrical facilities in the Toronto Region are Hydro One Networks Inc. Distribution, Alectra Utilities and Elexicon Energy Inc. The LDCs receive power at the step-down transformer stations and distribute it to the end-users – industrial, commercial and residential customers.

A single line diagram showing the electrical facilities of the Toronto Region is provided in Figure 3-1. Copeland MTS is a new THESL owned transformer station which serves the Downtown area and came into service in Q1 2019.

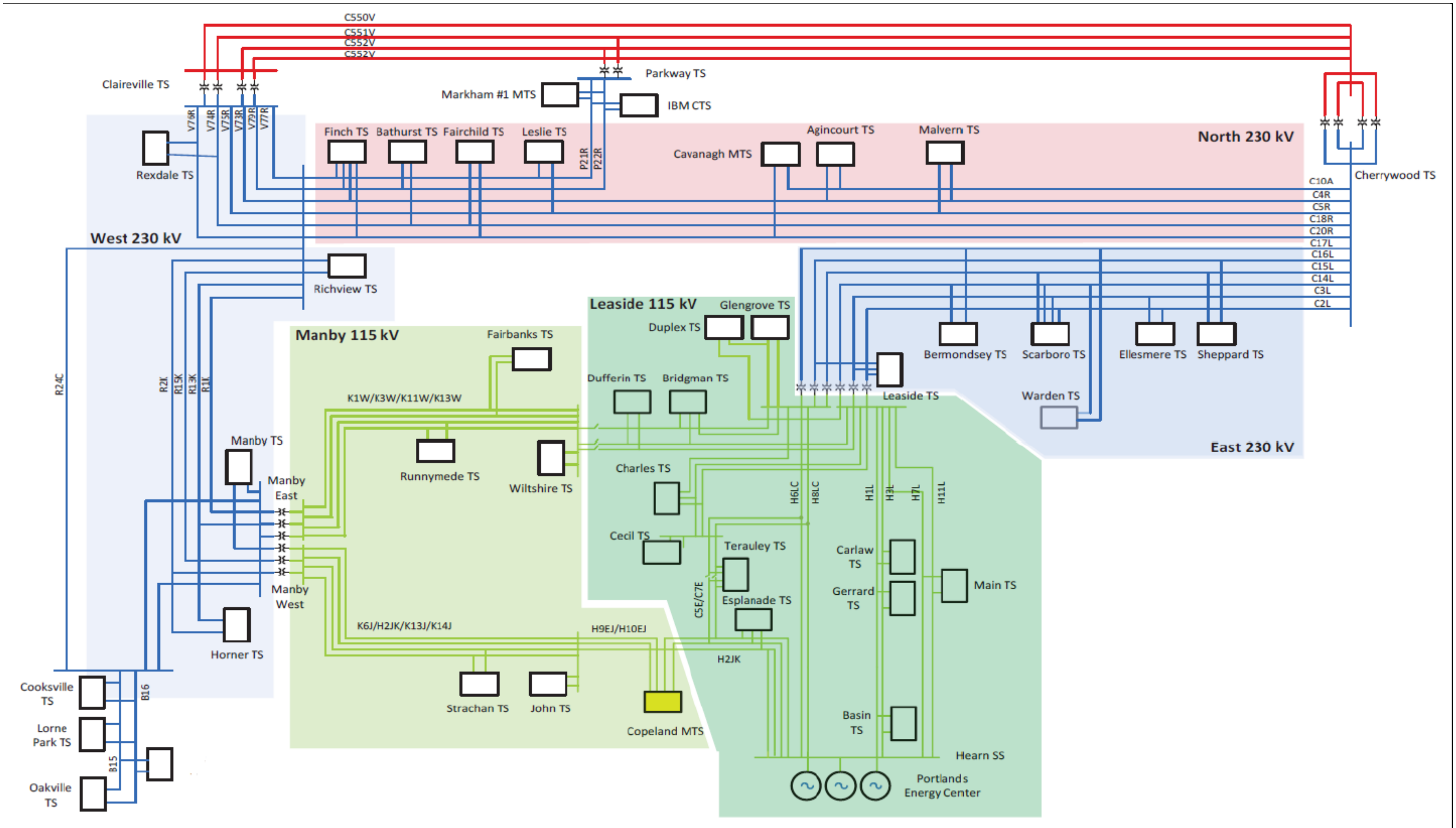


Figure 3-1: Single Line Diagram of Toronto Region's Transmission Network

The thirty-five Toronto's transformer stations can be grouped into five electrical zones based on their HV supply network:

1. **Leaside 115 kV Area:** The transformer stations in this area are supplied by the Leaside TS 230/115 kV autotransformers, and serve roughly the customers in the eastern part of Central Toronto. A list of the transformer stations in this area is provided below.
    - Basin TS
    - Bridgman TS
    - Carlaw TS
    - Cecil TS
    - Charles TS
    - Dufferin TS
    - Duplex TS
    - Esplanade TS
    - Gerrard TS
    - Glengrove TS
    - Main TS
    - Terauley TS

2. **Manby 115 kV Area:** This area covers the western part of Central Toronto which is supplied by the Manby TS 230/115 kV autotransformers. The transformer stations in this area is listed below.
    - Copeland MTS
    - Fairbank TS
    - John TS
    - Runnymede TS
    - Strachan TS
    - Wiltshire TS

3. **East 230 kV Area:** This area includes transformer stations connected to the 230 kV circuits between Cherrywood TS and Leaside TS C2L/C3L, C14L/C15L, and C16L/C17L, serving customers in the outer-eastern part of Toronto and Scarborough areas. Below are the transformer stations in East 230 kV area.
    - Bermondsey TS
    - Ellesmere TS
    - Leaside TS
    - Scarboro TS
    - Sheppard TS
    - Warden TS

4. **North 230 kV Area:** This area covers the outer northern part of Toronto bordering the York Region. The transformer stations in this area, listed below, are supplied by the 230kV circuits connecting Richview TS, Cherrywood TS, and/or Parkway TS C4R/C5R, C18R/C20R, P21R/P22R.
    - Agincourt TS
    - Bathurst TS
    - Cavanagh MTS
    - Fairchild TS
    - Finch TS
    - Leslie TS
    - Malvern TS

5. **West 230 kV Area**: The transformer stations in this area serve customers in the outer western part of Toronto including Etobicoke, and includes stations supplied by the Claireville TS to Richview TS 230 kV circuits V73R/V74R/V75R/V76R/V77R/V79R and the Richview TS to Manby TS 230 kV circuits R1K/R2K and R13K/R15K. Below are the transformer stations in West 230 kV area.
    - Horner TS
    - Manby TS
    - Rexdale TS
    - Richview TS

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE TORONTO REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Incorporation of the 550 MW Portland's Energy Centre (2009) – Covered modification to the Hearn 115 kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS, and Manby TS (2013, 2014) – Includes replacement of the aging 115 kV switchyard at Hearn SS with a new gas-insulated switchgear ("GIS") and replacement of all 115 kV oil breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – Re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance and improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – Covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (completed in 2016) – Covered replacement of the aging L14W underground cable and addition of a new 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115 kV Switching Station (completed in 2019) – Built to connect a new THESL owned 115/13.8 kV step-down transformer station (Copeland MTS) in Downtown Toronto.

- Runnymede TS DESN#2 and Manby TS to Wiltshire TS Circuits Upgrade Project (2018) – covered building of a second 50/83MVA, 115/27.6kV DESN at Runnymede TS and reinforcement of the Manby TS to Wiltshire TS 115kV circuits to accommodate increasing load demand in the area.

- Manby SPS Load Rejection (L/R) Scheme (2019) – Built to ensure that loading on in-service equipment at Manby TS is not exceeded for loss of two out of three autotransformers in the Manby East TS and Manby West switchyards.

- Horner TS DESN #2 Project (2022) – covers construction of a second 75/125MVA, 230/28 kV, DESN at the Horner TS site to meet the load growth in the south west Toronto area.

- Richview to Manby Corridor Reinforcement (R X K) Project (2023)– Adding a third double-circuit line between Richview TS and Manby TS, aimed to increase the transmission line capacity between the two stations to meet forecast load demand in the South West GTA.

- Multiple Station Refurbishment Projects – Work is also under way on refurbishing Bridgman TS, Fairbank TS, Main TS and Runnymede TS DESN#1. These projects are expected to be completed between 2021 and 2024.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Toronto Region is anticipated to grow at an average rate of 0.9% over the next ten years. Figure 5-1 shows the Toronto Region's summer peak load forecast developed during the Toronto IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. Figure 4-1 also shows the Toronto region's non-coincident load forecast developed using the individual station's peak loads and which was used to determine the need for station capacity.

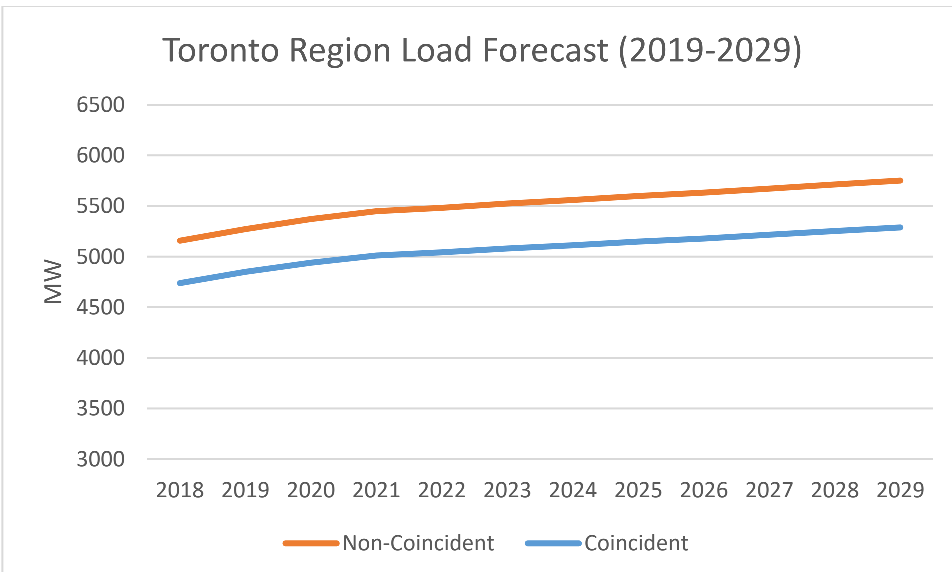


Figure 5-1: Toronto Region Load Forecast

The IRRP forecast shows that the Region peak summer load increases from 4850 MW in 2019 to 5290 MW by 2029. The corresponding non-coincident summer peak loads increase from 5270 MW to about 5750 MW over the same period. The IRRP and non-coincident load forecasts for the individual stations in the Toronto Region is given in Appendix D, Table D-1 and Table D-2.

The IRRP had provide an estimated of the energy-efficiency savings resulting from building codes and equipment standards improvement in Ontario. This has the potential to lower the demand growth in the region to approximately 0.6% annually. Details for the individual stations peak loads considering the energy-efficiency are given in Appendix D, Table D-3 and Table D-4.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect three Traction Power Substation (TPSS) to Hydro One's 230 kV circuits in Toronto area for GO Transit electrification – Mimico TPSS to K21C and K23C close to Manby TS; City View TPSS to V73R and V77R north of Richview TS; and Scarborough TPSS to C2L and C14L at Scarboro TS. Metrolinx have advised that their current electrification schedule is uncertain and new facilities would be built likely beyond 2023. Appendix F of the 2019 Toronto IRRP ("Richview TS x Manby TS Study") verified that the reinforcement of Richview TS to Manby TS Transmission Corridor is required by 2021 and that Metrolinx new load do not affect the need and timing of the project. After the completion of Richview TS to Manby TS Transmission Reinforcement, the new TPSS loads can be connected without need of any new facilities.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE TORONTO REGION OVER THE PLANNING PERIOD (2019-2039). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Toronto Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2017 Toronto Region Needs Assessment ("NA") Report
- 2019 Toronto Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the Metro Toronto Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D from a loading perspective. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 are in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
Second DESN at Horner TS	2022
Richview to Manby 230 kV Corridor Reinforcement	2023
Copeland MTS Phase 2	2024

6.1 230 kV Transmission Facilities

The Metro Toronto 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1):

a) Cherrywood TS to Leaside TS 230 kV circuits: C2L, C3L C14L, C15L, C16L, and C17L
b) Cherrywood TS to Agincourt TS 230 kV circuit C10A
c) Cherrywood TS to Richview TS 230 kV circuits: C4R, C5R, C18R, and C20R
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R
e) Claireville TS to Richview TS 230 kV circuits: V73R, V74R, V75R, V76R, V77R, and V79R
f) Richview TS to Manby TS 230 kV circuits: R1K, R2K, R13K, and R15K

The Cherrywood TS to Richview TS circuits, the Parkway TS to Richview TS circuits, and the Claireville TS to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate[2] over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh MTS. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230 kV circuits supply the Leaside TS 230/115 kV autotransformers as well as serve local area load. These circuits are adequate over the study period.

The Richview TS to Manby TS circuits supply the Manby TS 230/115 kV autotransformer station as well as Horner TS. With the Richview to Manby 230 kV Corridor Reinforcement in-service in 2023, the circuits will be adequate over the study period.

6.2 230/115 kV Autotransformers Facilities

The autotransformers at Manby TS and Leaside TS serve the 115 kV transmission network and local loads in Central Toronto. A 550 MW generation facility Portlands Energy Centre ("PEC") is situated in Central Toronto, connecting to the 115 kV transmission system at Hearn Switching Station ("SS").

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Manby East TS 230/115 kV autotransformers: T7, T8, T9
b. Manby West TS 230/115 kV autotransformers: T1, T2, T12
c. Leaside TS 230/115 kV autotransformers: T11, T12, T14, T15, T16, T17

Manby East and West TS autos supply two distinct 115 kV load pockets. Manby East TS autos supply Runnymede TS, Fairbank TS, and Wiltshire TS through the Manby TS to Wiltshire TS circuits. Manby West TS autos normally supply the Strachan TS, John TS, and Copeland MTS through Manby TS to John TS circuits. The Manby TS autotransformer facilities are adequate over the study period.

Leaside TS autos supply the rest of the 115kV transformer stations – Basin TS, Bridgman TS, Carlaw TS, Cecil TS, Charles TS, Dufferin TS, Duplex TS, Esplanade TS, Gerrard TS, Glengrove TS, Main TS, and Terauley TS. The Leaside TS autotransformer facilities are adequate over the study period.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities in the Metro Toronto Region serve local station loads in the Central Toronto area and are connected to the rest of the grid via Manby TS and Leaside TS autotransformers. The 115 kV transmission facilities can be divided into nine main corridors summarized below.

a. Manby East TS x Wiltshire TS – Four circuits K1W, K3W, K11W, and K12W

[2] Adequate – means that current flows are with conductor or equipment thermal limits and all area bus voltages meet the Ontario Resource and Transmission Assessment Criteria (ORTAC) under normal and contingency conditions.

b. Manby West TS x John TS – Six circuits H2JK, K6J, K13J, K14J, D11J, and D12J
c. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C
d. Leaside TS x Hearn SS – Six circuits H6LC, H8LC, H1L, H3L, H7L, and H11L
e. Leaside TS x Wiltshire TS – Four circuits L13W, L14W, L15, and L18W
f. Leaside TS x Duplex TS and Glengrove TS – Four circuits L5D, L16D, L2Y, and D6Y
g. Cecil TS x Esplanade TS – Two circuits C5E and C7E
h. John TS x Esplanade TS x Hearn SS – Three circuits H2JK, H9DE/D11J, and H10DE/D12J

The Manby East TS to Wiltshire TS 115 kV circuits supply Runnymede TS, Fairbank TS, and Wiltshire TS and were identified as requiring reinforcement in the 2016 Metro Toronto RIP. This work was completed in November 2018. With the completion of this work, the corridor circuits are adequate over the study period.

The Manby West TS to John TS 115 kV circuits supply Strachan TS, John TS and Copeland MTS. The corridor circuits are adequate over the study period.

The Leaside TS to Cecil TS 115 kV circuits and the Leaside TS to Hearn SS 115 kV circuits supply Basin TS, Carlaw TS, Cecil TS, Charles TS, Gerrard TS, and Main TS. The circuits are adequate over the study period.

The Leaside TS to Wiltshire TS corridor supply Bridgman TS and Dufferin TS. It has been recently reinforced with the addition of the L18W circuit in 2016 (Midtown transmission reinforcement). With the completion of this work the existing corridor circuits are adequate over the study period.

The Leaside TS to Duplex TS and Glengrove TS circuits (L5D, L16D, L2Y, and D6Y) are radial circuits that supply loads at Duplex TS and Glengrove TS. The circuits are adequate over the study period.

The Cecil TS to Esplanade TS circuits supply Terauley TS. The circuits are adequate over the study period.

The John TS to Esplanade TS and Hearn SS supply Esplanade TS. The circuits are adequate over the study period.

6.4 Step-Down Transformer Station Facilities

There are a total of 35 step-down transformers stations in the Toronto Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations summer peak load forecast are given in Appendix D Table D-1.

Table 6-2: Toronto Step-Down Transformer Stations

230 kV Connected		115 kV Connected		
Agincourt TS	Leslie TS	Basin TS	Esplanade TS	Fairbank TS
Bathurst TS	Malvern TS	Bridgman TS	Gerrard TS	Copeland MTS
Bermondsey TS	Rexdale TS	Carlaw TS	Glengrove TS	John TS
Cavanagh MTS	Scarboro TS	Cecil TS	Main TS	Strachan TS
Ellesmere TS	Sheppard TS	Charles TS	Terauley TS	Horner TS
Fairchild TS	Warden TS	Dufferin TS	Wiltshire TS	Manby TS
Finch TS	Richview TS	Duplex TS	Runnymede TS	
Leaside TS				

With the construction of the second DESN at Runnymede TS (completed in 2018) and the second DESN at Horner TS (planned to be in-service by 2022), there will be adequate transformer station capacity over the study period.

6.5 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040. The results indicate that the following facilities may be overloaded or reach capacity over this period.

- Manby West TS 230/115 kV autotransformers, which is limited by the lowest rated unit T12 in the fleet. T12 autotransformer replacement, planned to be completed by 2025, is expected to relieve this constraint.
- Leaside TS 230/115 kV autotransformers. This capacity need is based on the assumption that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. Refer to Appendix D of 2019 Toronto IRRP ("Planning Study Results") for more details.
- Table 6.3 and 6.4 provide the adequacy summary of the transmission circuits and transformer stations potentially requiring relief within the 2030-2040 period.

Table 6-3: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability	Limiting Element	Limiting Contingency	Need Date
	2030	2035	2040				
115 kV Leaside TS x Wiltshire TS corridor	309	332	342	340	L15	L14W	2035-2040
115 kV Manby W TS x Riverside Jct. corridor	487	517	547	510	K13J	H2JK	2030-2035

(1) The sum of station's coincident summer peak load adjusted for extreme weather, excluding energy-efficiency savings, assuming normal supply configuration, without load transfer

Table 6-4: Longer Term Adequacy of Step-Down Transformer Stations

Facilities	Station MW Load (1)			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Fairbank TS	182	188	193	182	2030-2035
Sheppard TS	203	216	224	204	2030-2035
Strachan TS	167	182	193	169	2030-2035
Basin TS	85	91	95	88	2030-2035

(1) Station's non-coincident summer peak load, adjusted for extreme weather, excluding energy-efficiency savings

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE TORONTO REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the Toronto Region and plans to address these needs. The electrical infrastructure needs in the Toronto Region are summarized below in Table 7.1 and Table 7.2. Except for the Richview to Manby Reinforcement, these needs are primarily associated with the replacement of end-of-life equipment.

Table 7-1: Identified Near and Mid-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.1	Main TS	End-of-life of transformers T3 and T4	2021
7.2	H1L/H3L/H6LC/H8LC	End-of-life of overhead line section between Leaside 34 Jct. & Bloor St. Jct.	2023
7.3	L9C/L12C	End-of-life of overhead line section between Leaside TS & Balfour Jct.	2023
7.4	C5E/C7E	End-of-life underground cables between Esplanade TS & Terauley TS	2024
7.5	Richview TS to Manby TS 230 kV Corridor	Additional load meeting capability upstream of Manby TS (Richview TS to Manby TS 230 kV corridor)	2023
7.6	Manby TS	End-of-life of autotransformers T7, T9, T12, step-down transformer T13, and the 230 kV switchyard at Manby TS	2025
7.7	Bermondsey TS	End-of-life of transformers T3, T4 at Bermondsey TS	2025
7.8	John TS	End-of-life of T1, T2, T3, T4, T5, T6 transformers, 115 kV breakers, and LV switchgear at John TS	2026

Table 7-2: Identified Long-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.9.1	Fairbank TS	Station capacity exceeded	2030-2035
7.9.2	Sheppard TS	Station capacity exceeded	2030-2035
7.9.3	Strachan TS	Station capacity exceeded	2030-2035
7.9.4	Basin TS	Station capacity exceeded	2030-2035
7.9.5	115 kV Manby W TS x Riverside Jct. corridor	Manby TS x Riverside Jct section of circuit K13J overloaded for circuit H2JK contingency	2030-2035
7.9.6	Manby W TS Autotransformers	Autotransformer T12 overloaded for T1 or T2 contingency	2030-2035
7.9.7	115 kV Leaside TS x Wiltshire TS corridor	Leaside TS to Balfour Jct. section of circuit L15 overloaded for circuit L14W contingency	2035-2040
7.9.8	Leaside TS Autotransformers	Autotransformer T16 overloaded for circuit C15L or C17L contingency, assuming 160 MW at Portlands GS	2035-2040

7.1 Main TS: End-of-Life Transformers

7.1.1 Description

Main TS is a 115/13.8 kV transformer station serving the eastern part of Central Toronto including the Beaches and Danforth area. The station is electrically situated within the Leaside 115 kV zone, supplied via 115 kV circuits H7L/H11L (see Figure 7-1). Peak demand at Main TS has been on average 59 MW over the last 3 years and is expected to increase to 62 MW over the next 10 years.

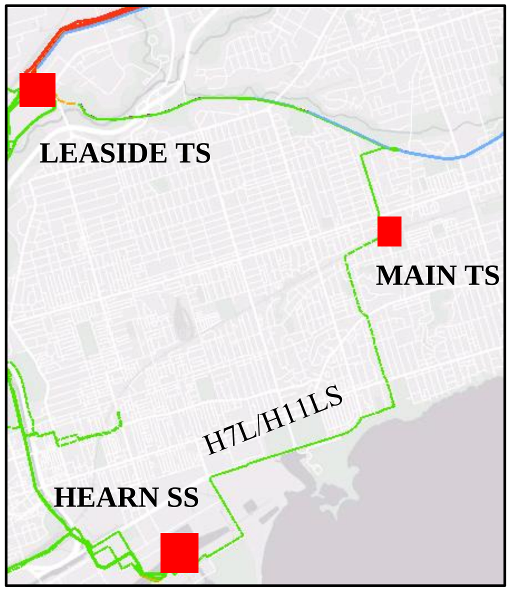


Figure 7-1: Main TS

The two transformers at Main TS (T3 and T4) are 46-51 years old 75 MVA units and are reaching their end-of-life. In addition, other equipment in the station, such as 115 kV line disconnect switches, current and voltage transformers, are also reaching their end-of-life.

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformers at Main TS are replaced with new 115/13.8 kV transformers. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 - Converting Main TS to 230 kV operation:** This alternative would require replacing the existing transformers with new 230/13.8kV transformers and building a new 230kV supply to Main TS from either Warden TS or Leaside TS. The existing H7L/H11L circuits cannot be used as they are required for Hearn TS x Leaside TS use. This alternative is significantly more costly (3-4 times) compared to Option 2 as it would require building the new 230 kV supply in addition to replacing the transformers. It was therefore not considered further.
4. **Alternative 4 - Supplying Main TS switchgear from new transformers at Warden TS:** Under this alternative instead of replacing the existing aging transformers at Main TS, new 230/13.8 kV transformers will be installed at Warden TS, a 230/27.6 kV transformer station located approximately 4.5 km north-east of Main TS. This alternative is significantly more (3-4 times) costly compared to Option 2 due to the excessive amount of distribution cables required to connect the transformers at Warden TS to the switchgear at Main TS. It was therefore not considered further.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative to refurbish Main TS. Further given the longer term potential for growth; need to provide system resiliency and flexibility; and insignificant incremental cost difference between 45/75 MVA and 60/100 MVA transformers, the Study Team recommends that Hydro One replace the existing transformers with larger 60/100 MVA units. The plan cost is estimated to be about $33 million, and is expected to in-service by end 2021.

7.2 H1L/H3L/H6LC/H8LC: End-of-Life Overhead Section (Leaside 34 Jct. to Bloor St. Jct.)

7.2.1 Description

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. are determined to be approaching their end-of-life. Figure 7.2 shows the location of the end-of-life section.

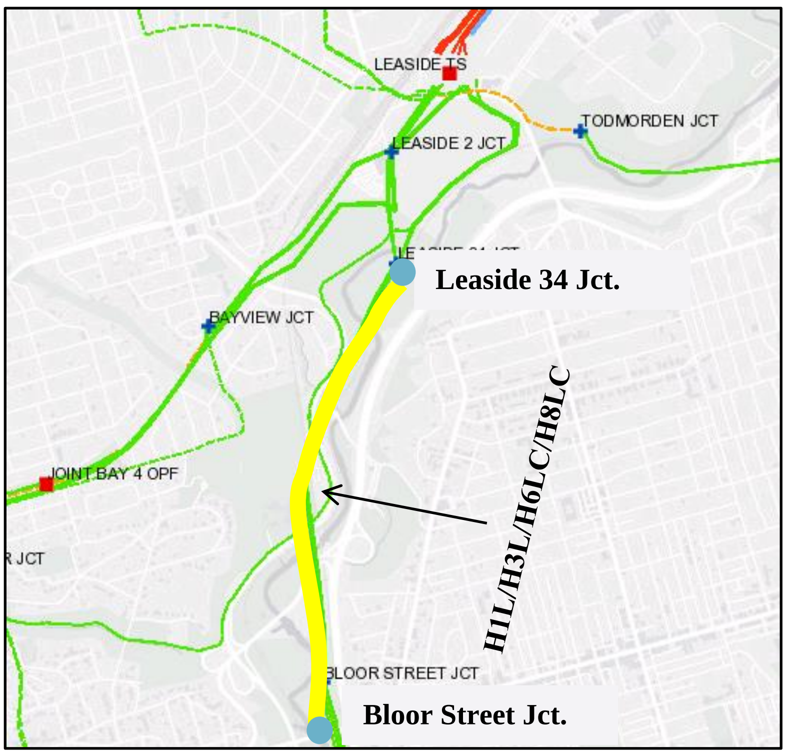


Figure 7-2: H1L/H3L/H6LC/H8LC Section between Leaside 34 Jct. and Bloor St. Jct.

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Under this alternative the existing end-of-life overhead section will be refurbished and the conductor will be replaced with largest size possible while retaining existing tower structures. This alternative addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.
3. **Alternative 3 –Replace and rebuild line for future 230 kV operation:** Under this alternative the line would be rebuilt to 230kV standards so as to be able for future 230kV operation. This alternative would be significantly more costly than Alternative 2 and with no plans to utilize the line at the higher operating voltage, was rejected and not considered further.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section. The line refurbishment work is expected to be complete by 2023.

7.3 L9C/L12C: End-of-Life Overhead Section (Leaside TS to Balfour Jct.)

7.3.1 Description

The overhead section of 115 kV double circuit line L9C/L12C between Leaside TS and Balfour Jct. is over 80 years old and has been determined to be approaching its end-of-life. Figure 7.3 shows the location of the end-of-life section.

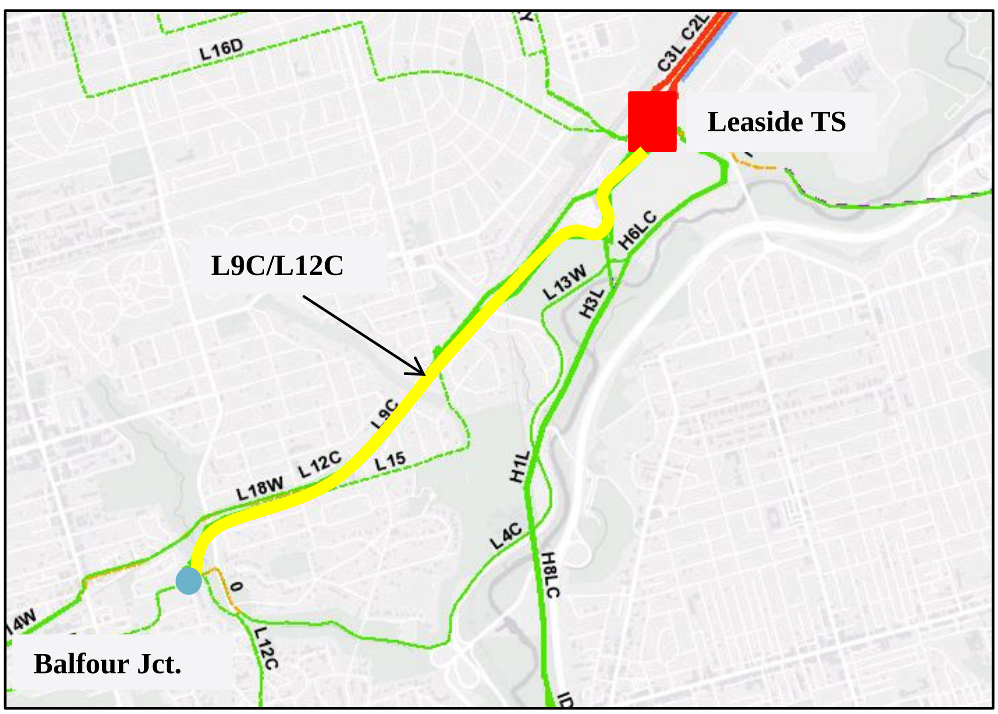


Figure 7-3: L9C/L12C Section between Leaside TS and Balfour Jct.

7.3.2 Alternatives and Recommendation

The following alternatives are considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Refurbish the end-of-life overhead section and replace conductors with the largest size possible while retaining existing tower structures. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section of L9C/L12C between Leaside TS and Balfour Jct. The line refurbishment work is planned to be completed by 2023.

7.4 C5E/C7E: End-of-Life Underground Cables (Esplanade TS to Terauley TS)

7.4.1 Description

Circuits C5E and C7E between Esplanade TS to Terauley TS are 115 kV paper insulated low pressure oil filled underground transmission cables that provide a critical 115 kV supply to Toronto's downtown core and are partially routed along Lake Ontario.

These circuits, put into service in 1959, are among the oldest cable circuits in the Hydro One's transmission system. Based on condition test results, the cable jackets and paper insulation were found to be in deteriorated condition which can lead to overheating, oil leaks, and cable failure. Figure 7.3 shows the location of the end-of-life section.

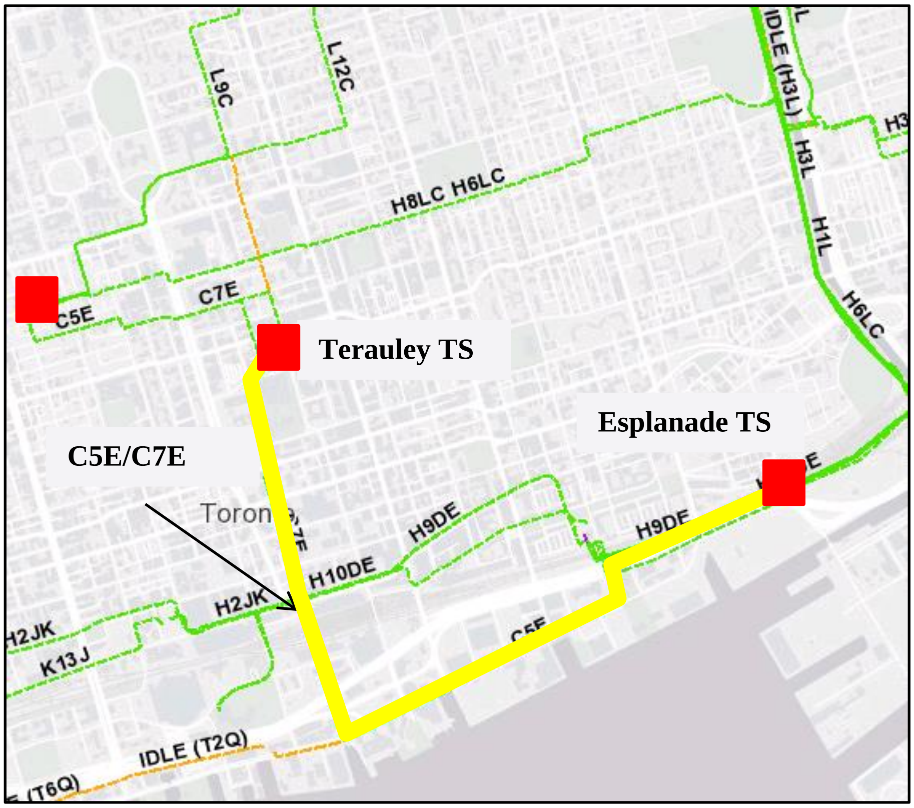


Figure 7-4: C5E/C7E Underground Cable Section between Esplanade TS and Terauley TS

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure to these cables can impact the power supply to critical facilities in Downtown Toronto. A large oil leak would have significant environmental impact and require costly environmental remediation.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative, the existing cables will be replaced with new 230 kV rated cables. The 230 kV rated cables have higher insulation and are less prone to failure. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the replacement of the end-of-life underground cables between Esplanade TS and Terauley TS. Hydro One is currently proceeding with detailed estimation of options including tunneling for evaluating the most appropriate routes and construction options. This will be an input for public consultations to obtaining permit and necessary approvals along with environmental assessments. A final route and installation option will be selected as part of the open EA process. The cable refurbishment work is planned to be completed by 2024.

7.5 Richview TS to Manby TS 230 kV Corridor

7.5.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The first cycle Metro Toronto Regional Infrastructure Plan has identified the need to increase transfer capability of this transmission corridor to support the continuous load growth in these areas.

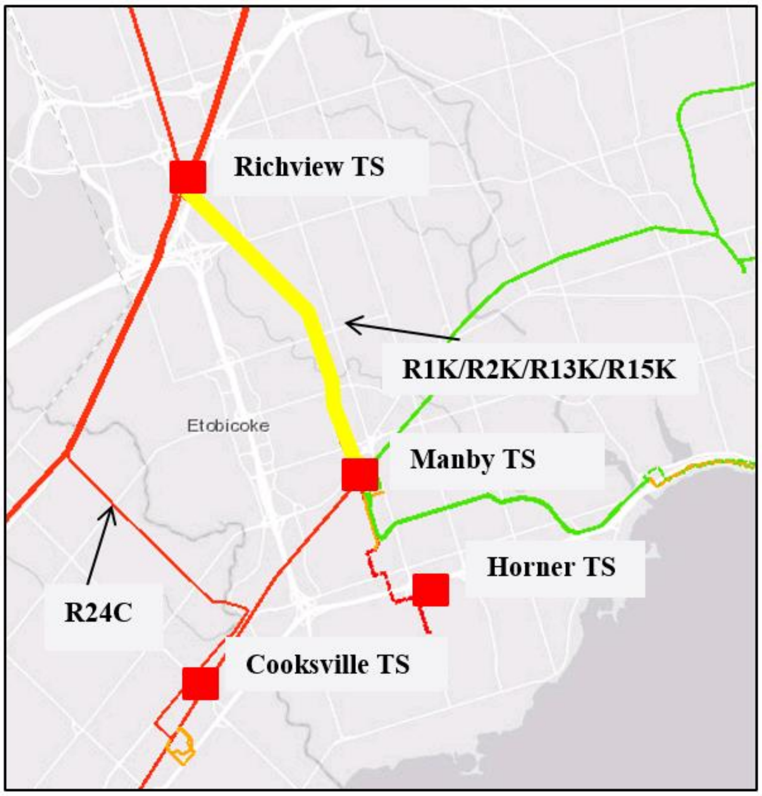


Figure 7-5: Richview TS to Manby TS 230 kV Corridor

7.5.2 Alternatives and Recommendation

A detailed assessment of the Richview TS to Manby TS corridor need was carried out in the Appendix F of the Toronto IRRP to reconfirm the capacity need of this corridor based on the changes in assumptions and the up-to-date load forecast. The assessment confirmed the need, and the Study Team continues to recommend that the reinforcement of the Richview TS to Manby TS 230 kV circuits to be completed as soon as possible.

Evaluation of alternatives was completed by the Study Team as documented in the 2015 Toronto Regional Infrastructure Plan. As per the Study Team's recommendation, Hydro One is proceeding with the Richview TS to Manby TS 230 kV transmission reinforcement project, which will be carried out in two phases:

- **Phase 1:** This phase covers rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This configuration avoids the need to build new terminations and new breakers at Manby TS. The IRRP noted the need for Phase 1 is in 2021 but the expected in-service is Q4 2023. Figure 7-6 below shows the transmission configuration after Phase 1 is completed.

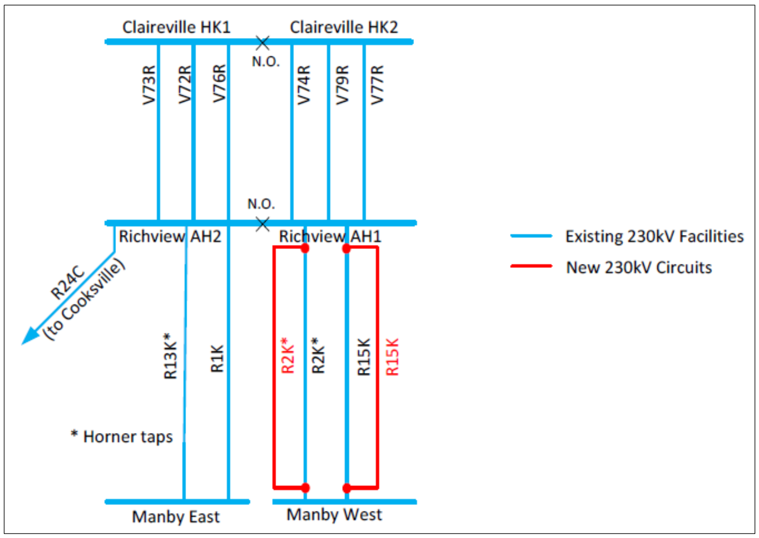


Figure 7-6: Richview TS to Manby TS 230 kV Corridor – Phase 1

i. **Phase 2:** In the second phase the super circuits will be unbundled with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS end of life refurbishment, all of which is planned to be complete by 2025. Figure 7-7 below shows the transmission configuration after Phase 2 is completed. Note that the nomenclature shown for the new circuits are for illustrative purposes only and subject to change.

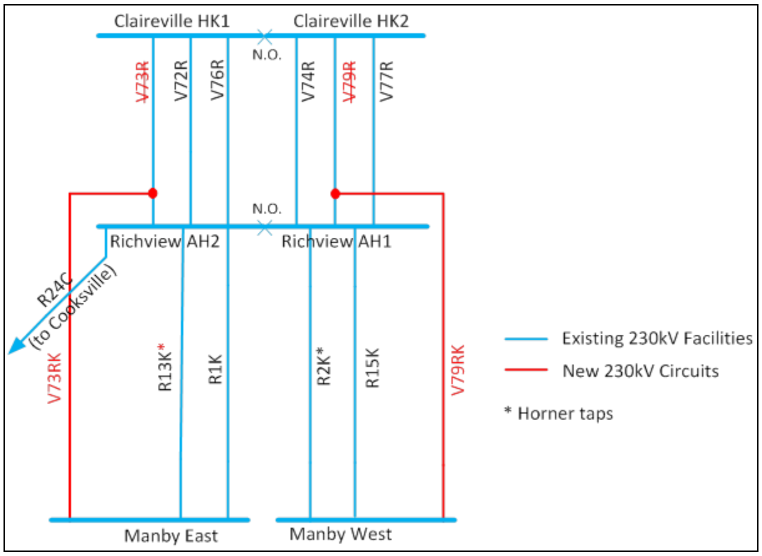


Figure 7-7: Richview TS to Manby TS 230 kV Corridor – Phase 2

7.6 Manby TS: End-of-Life Transformers and 230 kV Switchyard

7.6.1 Description

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

The Manby TS autotransformers T7, T9, and T12 and step down transformer T13 are about 50 years old and all four have been identified to be nearing the end of their useful life and require replacement in the next 5 years. All three DESNs at Manby TS are currently at capacity, and the new second DESN at nearby Horner TS (I/S 2022) is expected to pick-up the load growth in the area.

The 230 kV oil breakers have also been identified to be nearing end-of-life and require replacement over the next 5-year period. As part of breaker replacement work, the 230 kV Manby West and Manby East switchyards will be modified and an additional three breakers added to terminate the two new circuits to Richview TS described above in Section 7.5 under Phase 2 for the Richview TS to Manby TS corridor reinforcement.

Figure 7-8: Manby TS

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.
2. **Alternative 2 - Replace the end-of-life transformers with similar type and size equipment as per current standard, and rebuild/modify the 230 kV switchyard:** This alternative involves the replacement of Manby East T7, T9, and Manby West T12 autotransformers with 250 MVA units; Manby T13 DESN transformers with 75/93 MVA unit; replacement of end-of-life 230 kV oil breakers; as well as 230 kV switchyard modification and installing three new breakers to accommodate the new circuits to Richview TS (as part of the Richview TS to Manby TS Corridor Reinforcement). This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers in the area by:
   - reducing the risk of breaker failure events at Manby TS;
   - providing relief to the autotransformer capacity constraints in the long-term at Manby West TS by replacing the lowest rated unit T12; and
   - connecting the new circuits to Richview TS to support the continuous load growth in these areas.

The Study Team recommends that Hydro One proceed with Alternative 2 – the end-of-life transformer replacement and rebuilding of the Manby TS 230 kV switchyard. The project is expected to be completed by 2025.

7.7 Bermondsey TS: End-of-Life Transformers

7.7.1 Description

Bermondsey TS along with Ellesmere TS, Scarborough TS, Sheppard TS and Warden TS supply the Scarborough area and comprises of two DESNs. The T1/T2 DESN was built in 1990, has 6 feeders, an LTR of 185.8 MW and supplied a summer 2018 peak load of 43 MW. The T3/T4 DESN was built in 1965, has 12 feeders, an LTR of 162.5 MW and supplied a 2018 summer peak load of 117 MW.

The T3 and T4 transformers are about 55 years old, have been identified as nearing the end of their useful life and requiring replacement in the next 5 years.

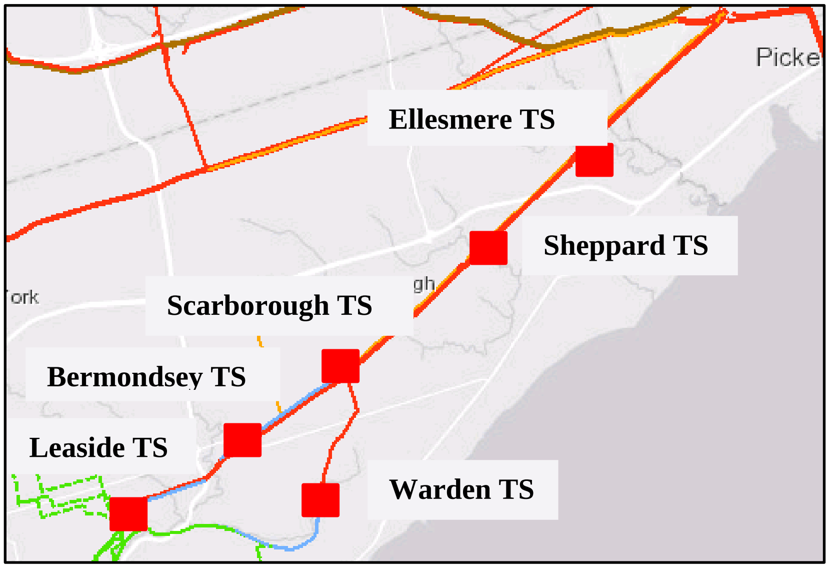


Figure 7-9: Bermondsey TS and Surrounding Stations

7.7.2 Alternatives and Recommendation

The recommendation for the end of life replacement is as follows:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 - Decommission the T3/T4 DESN at its end-of-life:** This alternative is not viable as there would be insufficient feeder capacity to supply the existing load. It was not considered further.
3. **Alternative 3 - Downsize (replace with smaller 83 MVA transformers):** This alternative would require extensive feeder transfers, and reconfiguration of the station including addition of new feeders on the T1/T2 DESN. The cost of the station reconfiguration work is expected to exceed $5M and significantly exceeds the $500-600k cost savings resulting from using the smaller size transformers.
4. **Alternative 4 - Replace with similar type and size equipment as per current standard:** This alternative is recommended as this is the most cost effective option, and addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 4 – the refurbishment of the T3/T4 DESN of Bermondsey TS and build to current standard. The refurbishment plan is expected to be in-service by 2025.

7.8 John TS: End-of-Life Transformers, 115 kV Breakers, and LV Switchgear

7.8.1 Description

John TS (also referred to as Windsor TS) is connected to the 115 kV Manby West system and supplies the western half of City of Toronto's downtown district. Station facilities include a 115 kV switchyard and six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5, T6) supplying six Toronto Hydro low voltage metalclad switchgears. The summer 10-day LTR is 311 MW. The station's 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 261 MW.

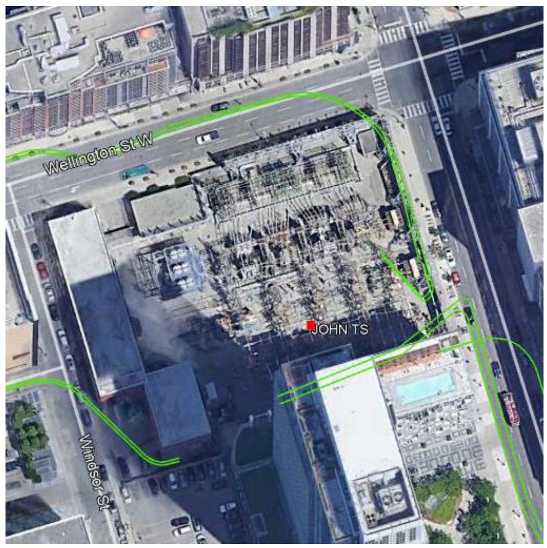


Figure 7-10: John TS

The T1 and T4 step-down transformers at John TS, both over 50 years old and in poor condition, were replaced in 2019. The step down transformers (T2, T3, T5 and T6) which range in age from 44-50 years are also at, or nearing, end of life. It is expected that these transformers will need to be replaced in the next 3-5 years. The 115 kV breakers are mostly oil type and are about 44 years old. They are also nearing end of useful life and are expected to require replacement in the next 5-10 years.

Toronto Hydro has also identified the need for renewal of their switchgear facilities at John TS. This work will be done over multiple phases and is expected to take 20-25 years to fully complete. The first phase involves relocating the feeders from switchgear at John TS to new switchgear at Copeland MTS so as to permit of the replacement of switchgear at John TS. The presence of Copeland MTS, which went into service in 2019, enables the switchgear replacement due to the capacity (transformation and feeder positions) at Copeland MTS that are not available at John TS or other neighboring stations. The load transfer to Copeland MTS is necessary to reduce load at John TS to facilitate the transformer and switchgear replacement work at John TS.

Toronto Hydro plan to initiate the switchgear renewal process starting with the Windsor Station A5-A6 and the A3-A4 metalclad switchgear buses. These buses are expected to be replaced by the new A19-A20 bus in 2022-2023 and later followed by A21-A22 bus. Hydro One will replace associated low voltage transformer breaker disconnect switches and cables in coordination with Toronto Hydro.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – Reducing the Number of Transformers from Six to Four Units:** As part of the John TS refurbishment work and the consequent reduction in loading at the station, Hydro One investigated the opportunity for reducing the number of 115/13.8 kV transformer units at John TS from the current six units to four units. Hydro One assessed with Toronto Hydro the feasibility of the following two options:
   i. Reducing the number of switchgear pairs in the station from the current six to four to match the supply from four transformers. The assessment concluded that Copeland MTS has only enough feeder positions available to pick up one bus (typically 14-16 feeders) from John TS, and therefore there are no additional feeder positions available at Copeland MTS to further eliminate another bus at John TS. As such this option is not feasible.
   ii. Reducing the number of transformer supply points to the existing six switchgear pairs through switchgear bus bundling (while not reducing the number of feeder positions at the station). This involved looking at opportunities of electrically joining presently distinct switchgear pairs while at the same time respecting equipment ratings. No opportunities were found that would respect equipment ratings. If opportunities that would respect equipment ratings had been found these would then be reviewed based upon operational factors involving customers impacted by a contingency, restoration times, etc. A first review of these operational factors found that Toronto Hydro's ability to perform bus load transfers would be limited than what it is today and its restoration times would be lengthened compared to what exists today due to the increased concentration of customers per bus. Given the lack of opportunities and the negative operational impacts even if opportunities were to be found, this option is not feasible.
   iii. Consistent with the IRRP load forecast, Toronto Hydro has cited continued electricity demand along with higher reliability from customers for new connections to its distribution system in the downtown core. The growth in new connections coupled with Toronto Hydro's distribution system for reliable service is leading to the demand for feeder positions outpacing the peak demand growth. Six switchgear pairs along with six transformer supply points are still required for John/Windsor TS.

   Based on the findings of above assessments, this alternative is not viable as Toronto Hydro feeder requirements are such that all of the six transformers are needed to supply load in the area via the six pairs of Toronto Hydro buses as described above.

3. **Alternative 3 - Similar Connection Arrangement with 60/100 MVA Transformers:** This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply

to the customers in the area. This alternative involves the replacement of the remaining T2, T3 (45/75 MVA), and T5, T6 (75/125 MVA) transformers with 60/100 MVA units, replacement of the LV switchgear in coordination with Toronto Hydro, and replacement of the existing oil filled breakers with SF6 breakers in the 115 kV switchyard. Minor modifications may be made (to the extent practically possible) to improve operational flexibility under outage conditions. Several options as described below were considered into the scope of the John TS refurbishment:

i. Downsize (replace with smaller size transformers): The renewal of John TS switchgear facilities is expected to be completed over multiple phases within the next 20-25 years. Over this time period, the load of an existing switchgear will be transferred from one transformer winding pairs to another to connect to the new switchgear. Since some of the switchgear is heavily loaded, all of the transformer windings should be able to handle the maximum load of a single switchgear (i.e., 3000 Amps). For this reason, downsizing of John TS transformers is not viable.

ii. Rebuild/reconfigure the 115 kV switchyard to a “Breaker-and-Half” configuration: The existing 115 kV breakers and buses are currently arranged in a ring-bus configuration and consideration was given to rebuilding and reconfiguring the 115 kV switchyard using a breaker and half arrangement. However, this alternative is not viable due to physical space constraints and clearances required for equipment and personnel safety. Although, practically constrained, this option will also require rerouting and retermination of high voltage cables and the cost of investment required for this reconfiguration significantly outweigh the incremental benefits.

The Study Team therefore recommends that Hydro One to proceed with Alternative 3 as described above. The John TS refurbishment plan is expected to be in service by 2026.

7.9 Long-Term Capacity Needs

A number of longer term capacity needs have been identified as described in Section 6.5 and Table 7.2. The Study team recommends that these needs be monitored and evaluated in future planning cycles. No investment is required at this time due to the forecast uncertainty and the longer-term timing of need. Preliminary comments are given below.

7.9.1 Fairbank TS Capacity Need

Fairbank TS load is expected to exceed LTR within the 2030-2035 time period. Consideration may be given to load transfer to the neighboring Runnymede TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.2 Sheppard TS Capacity Need

Sheppard TS is also forecast to exceed capacity within the 2030-2035 time period. Consideration may be given to utilizing the idle winding on transformers T1/T2. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.3 Strachan TS Capacity Need

Strachan TS is forecast to exceed capacity within the 2030-2035 time period. Consideration maybe given to provide relief to Strachan TS through permanent load transfers to Copeland MTS and/or John TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.4 Basin TS Capacity Need

Basin TS is located in the Portlands area in Downtown Toronto. The need for additional capacity at Basin TS is expected to arise in the long-term (within the 2030-2035 time period). The timing of the need is dependent on the pace of development in the area. Physical space is available at the current Basin TS site to plan and build a second DESN to meet long term needs.

The City of Toronto is planning the re-development of the Portlands. The area may see additional load beyond that which has been included in the present forecasts. The timing of any new needs will depend upon the timing of the City's plan.

However, the City's current re-development plans will end the continued operation of Basin TS and several high voltage lines in their current locations in the Portlands. This will significantly impact both Hydro One infrastructure and Toronto Hydro infrastructure within and outside of Basin TS. No sites for a replacement transformer station or high voltage line routes have been identified by the City.

Hydro One and Toronto Hydro have requested the City to revise its plans so as to avoid the conflicts with Basin TS and high voltage lines. Hydro One and Toronto Hydro have also joined others in a legal appeal of the City's land plans.

Given the appeal and lack of information currently available to Hydro One and Toronto Hydro from the City, the Study Team recommends that Hydro One and Toronto Hydro continue to monitor the situation and update the Study Team as appropriate. Plans for supplying the Portlands area will be developed as more information becomes known.

7.9.5 Manby West TS to Riverside Jct. Corridor Capacity Need

The Manby TS x Riverside Jct. section of K13J/K14J is potentially overloaded under certain contingency conditions within the 2030-2035 time period. Consideration may be given to reconductor circuit with a higher ampacity conductor. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.6 Manby West TS Autotransformers T12 Capacity Need

Manby West TS 230/115 kV autotransformers is restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. T12 autotransformer replacement, planned to be completed by 2025, is expected to provide relieve to this constraint and meet the capacity requirement at Manby West TS autotransformers facility. See Section 7.5 for more details.

7.9.7 Leaside TS to Wiltshire TS Corridor Capacity Need

The Leaside TS x Balfour Jct. section of the underground 115 kV circuit L15, connecting Leaside TS and Wiltshire TS, is potentially overloaded in the long-term within the 2035-2040 time period. The Study Team determines that no further investment is required to address this need at this time due to the level of uncertainties and amount of lead time available. This need will be reevaluated in the next planning cycle.

7.9.8 Leaside TS Autotransformers T16 Capacity Need

Leaside TS autotransformer T16 is potentially overloaded in the long-term within the 2035-2040 time period, following circuit C15L or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The Study Team determines that no further investment is required to address this need at this time due to the level of forecast uncertainty and amount of lead time available. The Study Team recommends reviewing the loading in the next planning cycle.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE TORONTO REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/ H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] **Metro Toronto Regional Infrastructure Plan (2016)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/RIP%20Report%20Metro%20Toronto.pdf

[2] **Toronto Region Needs Assessment (2017)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

[3] **Toronto Region Scoping Assessment (2018)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/Toronto-Scoping-Assessment-Outcome-Report-February-2018.pdf?la=en

[4] **Toronto Integrated Regional Resource Plan (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-20190809-Report.pdf?la=en

[5] **Toronto Integrated Regional Resource Plan - Appendices (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-Appendices.pdf?la=en

APPENDIX A. STATIONS IN THE TORONTO REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15
Dufferin TS T2/T4	115/13.8	L13W/L15
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

APPENDIX B. TRANSMISSION LINES IN THE TORONTO REGION

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

APPENDIX C. DISTRIBUTORS IN THE TORONTO REGION

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
Alectra Utilities	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
	Richview TS	Dx
Elexicon Energy Inc.	Malvern TS	Dx
	Sheppard TS	Dx

APPENDIX D. TORONTO REGION LOAD FORECAST

Table D-1: Toronto IRRP Load Forecast, without the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast												Long-Term Forecast		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	92	95	98	100	101	102	103	104	104	105	106	106	107	110	114
Bathurst TS	334	210	220	226	229	231	233	235	236	238	239	242	245	247	265	274
Cavanagh MTS	157	91	92	93	94	95	95	95	96	97	98	98	99	100	108	112
Fairchild TS	346	235	237	239	241	243	245	247	249	250	250	252	254	255	260	265
Finch TS	365	249	254	258	260	261	262	263	265	267	269	271	272	273	279	284
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	83	84	85	86	86	86	87	88	88	91	93	95	96	103	106
East 230 kV																
Bermondsey TS	348	148	152	154	156	159	160	161	162	164	164	165	165	165	166	172
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	151	156	160	163	164	165	165	167	168	168	169	169	169	171	178
Scarboro TS	340	204	207	209	211	212	213	214	216	218	218	218	219	219	230	236
Sheppard TS	205	141	144	146	148	148	150	151	153	153	153	156	159	161	171	177
Warden TS	182	106	108	109	110	111	112	113	113	113	117	120	122	124	132	136
West 230 kV																
Horner TS	365	133	137	138	140	140	142	143	144	145	149	154	158	161	177	187
Manby TS	226	191	202	205	211	212	215	216	217	219	220	222	224	226	240	251
Rexdale TS	187	123	124	125	125	127	127	129	129	129	129	127	127	125	118	110
Richview TS	460	227	213	217	219	220	222	223	224	226	224	222	219	218	213	204
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	162	170	175	177	179	181	182	183	184	182	180	178	177	177	177
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	121	124	125	125	126	127	128	130	134	135	139	142	152	156
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	162	142	145	146	146	148	148	149	150	149	147	146	143	147	148
Gerrard TS	102	35	44	47	49	49	50	50	50	51	51	51	51	51	52	53
Glengrove TS	88	48	50	50	51	51	51	51	51	51	52	54	55	56	60	62
Main TS	77	56	57	57	58	59	59	59	60	60	62	62	63	64	65	65
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	141	125	132	135	139	142	144	145	146	147	148	149	149	154	158
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	55	71	72	72	72	73	73	73	75	75	76	76	76	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	263	266	215	201	202	203	204	206	206	210	212	215	218	228	242
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

Table D-2: Toronto Non-Coincident Load Forecast, without the Impacts of Energy-Efficiency Savings

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW) 2018 (1)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Long-Term Forecast (MW) 2030	2035	2040
North 230 kV																
Agincourt TS	174	112	115	119	121	122	124	125	126	126	127	128	128	130	133	138
Bathurst TS	334	227	238	244	248	250	252	254	255	257	258	262	265	267	287	296
Cavanagh MTS	157	108	109	110	112	113	113	113	114	115	116	116	117	119	128	133
Fairchild TS	346	268	270	272	274	277	279	281	284	285	285	287	289	290	296	302
Finch TS	365	290	296	301	303	304	305	306	309	311	313	316	317	318	325	331
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	105	106	108	109	109	109	110	111	111	115	118	120	122	130	134
East 230 kV																
Bermondsey TS	348	160	164	166	169	171	173	173	175	177	177	178	178	178	179	186
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	163	169	174	177	178	179	179	181	182	182	183	183	183	186	194
Scarboro TS	340	222	225	227	229	231	232	233	235	237	237	237	238	238	250	257
Sheppard TS	205	178	182	184	187	187	189	191	193	193	193	197	201	203	216	224
Warden TS	182	123	125	126	127	129	130	131	131	131	135	139	141	144	153	157
West 230 kV																
Horner TS (2)	365	141	145	146	148	193	199	202	204	208	213	221	228	234	268	292
Manby TS (2)	226	245	258	262	269	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	138	139	139	141	141	143	143	143	143	141	141	139	131	122
Richview TS	460	279	263	268	270	271	274	275	276	279	276	274	270	269	263	252
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	166	174	179	181	183	185	186	187	188	186	184	182	181	181	181
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	120	123	124	124	125	126	127	129	133	134	138	141	151	155
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	163	143	146	147	147	149	149	150	151	150	148	147	144	148	149
Gerrard TS	102	37	46	49	51	51	52	52	52	54	54	54	54	54	55	56
Glengrove TS	88	51	53	53	54	54	54	54	54	54	55	57	58	59	63	65
Main TS	77	60	61	61	63	64	64	64	65	65	67	67	68	69	70	70
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	171	151	159	164	169	173	176	177	178	179	181	182	182	188	193
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	56	74	75	75	75	76	76	76	78	78	79	79	79	86	90
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	264	267	217	203	204	205	206	208	208	212	214	217	220	230	244
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

(1) Non-coincident station peak, adjusted to extreme weather
(2) Load transferred to the new Horner TS DESN #2 in 2022

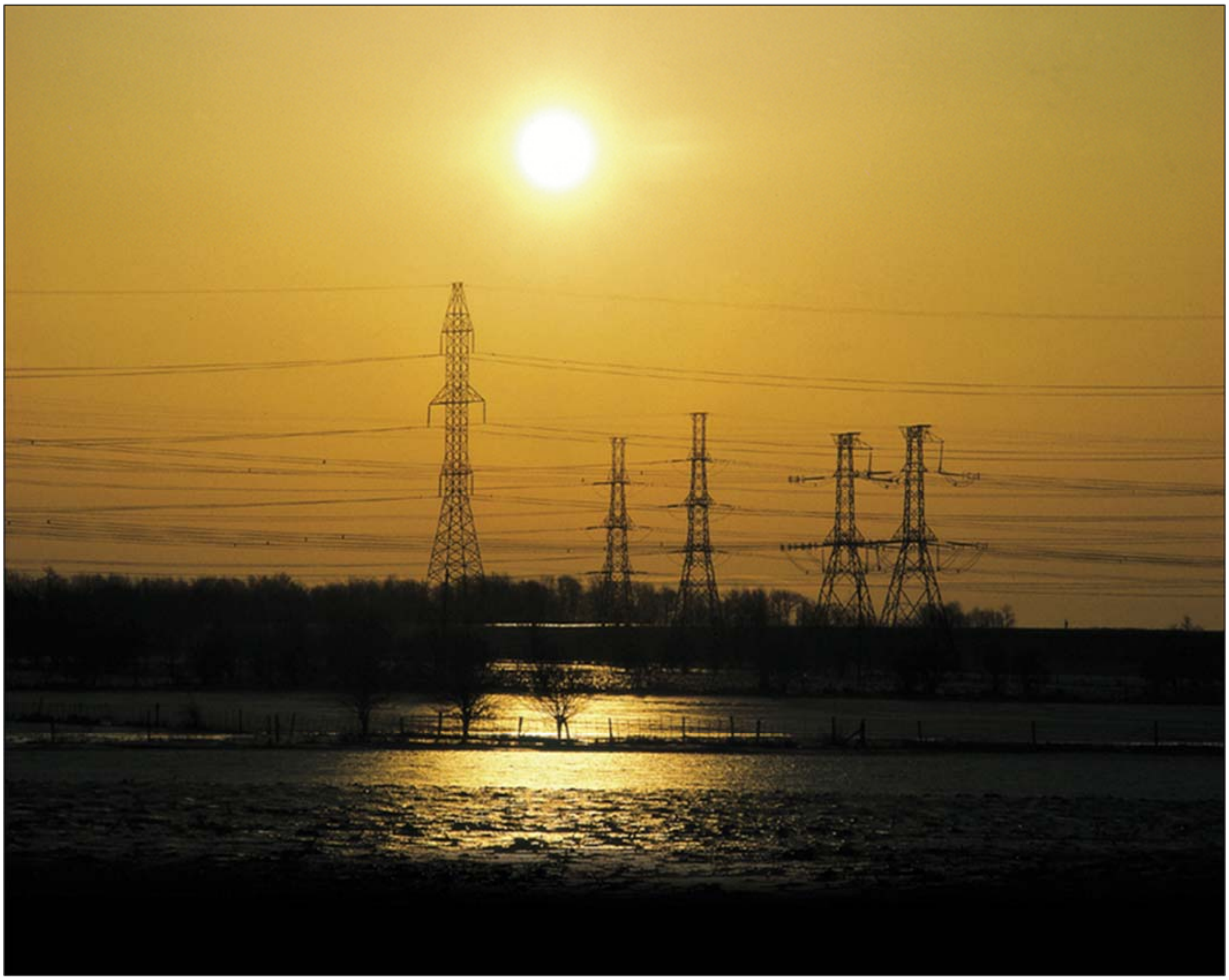
Table D-3: Toronto IRRP Load Forecast, with the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	91	94	96	98	99	100	100	101	101	102	102	102	103	105	108
Bathurst TS	334	208	217	222	225	226	227	229	229	231	231	233	235	237	252	260
Cavanagh MTS	157	90	91	92	92	93	93	93	93	94	95	95	95	96	103	107
Fairchild TS	346	232	233	234	236	237	238	239	241	241	240	241	242	242	244	249
Finch TS	365	247	251	254	256	256	256	257	258	260	261	263	263	263	267	272
Leslie TS	325	230	237	244	245	248	248	250	251	252	252	253	253	253	266	276
Malvern TS	176	82	83	84	85	84	84	85	86	86	88	90	92	93	99	101
East 230 kV																
Bermondsey TS	348	146	150	151	153	155	156	156	157	159	158	159	158	157	157	162
Ellesmere TS	189	123	124	126	127	127	128	128	128	129	128	129	129	128	128	131
Leaside TS	202	149	154	157	160	160	161	160	162	162	162	162	162	161	161	168
Scarboro TS	340	202	204	206	208	208	208	209	210	212	211	211	211	211	219	225
Sheppard TS	205	140	141	143	145	144	146	146	148	148	147	150	152	153	161	167
Warden TS	182	105	106	107	108	109	109	110	109	109	113	115	117	118	125	129
West 230 kV																
Horner TS	365	132	135	136	138	137	139	139	140	141	144	148	152	154	168	177
Manby TS	226	189	199	202	207	208	210	210	211	212	212	214	215	216	227	238
Rexdale TS	187	121	122	123	122	124	123	125	124	124	123	121	120	118	110	102
Richview TS	460	224	209	213	214	215	216	216	216	218	215	213	209	207	200	192
Leaside 115 kV																
Basin TS	88	64	70	74	75	75	75	76	77	76	78	80	80	81	86	90
Bridgman TS	212	152	151	153	154	153	156	156	156	156	157	157	157	159	169	175
Carlaw TS	73	62	63	63	63	64	63	64	64	65	64	64	64	66	65	65
Cecil TS	215	160	167	172	174	175	176	177	177	178	175	173	170	169	167	167
Charles TS	211	143	149	151	152	152	154	153	154	153	155	157	158	159	165	166
Dufferin TS	170	134	119	122	123	122	123	123	124	126	129	130	133	135	143	147
Duplex TS	128	98	99	98	96	95	91	91	93	94	94	95	95	97	102	106
Esplanade TS	187	160	140	142	143	143	144	144	144	145	144	141	140	136	139	140
Gerrard TS	102	32	41	43	45	45	46	46	46	47	46	46	46	46	46	47
Glengrove TS	88	47	49	49	50	50	50	49	49	49	50	52	52	53	56	58
Main TS	77	55	56	56	57	58	57	57	58	58	60	59	60	61	61	61
Terauley TS	249	173	185	190	186	184	183	185	185	184	183	179	177	175	171	172
Manby E 115 kV																
Fairbank TS	182	139	123	130	132	136	138	140	141	141	142	142	143	142	146	149
Runnymede TS	219	95	134	139	140	140	143	142	144	143	144	144	145	144	150	155
Wiltshire TS	133	54	70	71	71	70	71	71	71	73	72	73	73	73	78	81
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	256	258	207	193	194	194	194	196	195	198	200	202	204	211	224
Strachan TS	169	137	141	142	143	144	143	145	144	145	149	152	156	159	172	182

Table D-4: Toronto Non-Coincident Load Forecast, with the Impacts of Energy-Efficiency Savings

Area & Station	LTR (MW)	2018 (1)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
North 230 kV																
Agincourt TS	174	112	115	118	120	121	122	123	124	124	124	125	125	126	128	133
Bathurst TS	334	227	237	243	246	247	249	250	251	252	252	255	257	259	275	285
Cavanagh MTS	157	108	109	110	111	112	111	111	112	113	114	113	114	115	123	128
Fairchild TS	346	268	269	270	272	273	275	276	277	278	277	278	279	279	282	287
Finch TS	365	290	295	299	301	302	302	303	304	306	307	309	309	310	314	320
Leslie TS	325	233	240	247	248	251	251	253	255	255	255	256	256	256	270	279
Malvern TS	176	105	106	107	108	108	108	109	110	110	113	115	117	118	126	130
East 230 kV																
Bermondsey TS	348	160	164	165	168	169	170	170	171	173	172	173	172	172	171	178
Ellesmere TS	189	124	126	127	128	129	129	129	130	130	130	130	130	130	129	132
Leaside TS	202	163	169	173	176	176	176	176	178	178	177	178	177	177	177	185
Scarboro TS	340	222	224	226	228	228	229	229	231	233	232	231	232	231	241	247
Sheppard TS	205	178	180	182	185	184	186	187	189	188	188	191	194	196	206	213
Warden TS	182	123	124	125	126	127	128	129	128	128	132	135	137	139	146	151
West 230 kV																
Horner TS (2)	365	141	145	146	147	189	194	195	196	199	203	209	214	219	247	271
Manby TS (2)	226	245	257	260	267	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	137	138	137	139	138	140	140	139	139	136	135	133	123	115
Richview TS	460	279	262	266	268	268	270	270	270	272	269	266	261	259	250	240
Leaside 115 kV																
Basin TS	88	65	71	75	75	76	76	77	77	77	79	81	81	82	87	91
Bridgman TS	212	154	153	155	156	155	158	158	158	158	159	159	159	161	171	177
Carlaw TS	73	66	67	67	67	67	67	68	68	69	68	68	68	70	69	69
Cecil TS	215	166	173	178	180	181	183	183	183	184	182	179	176	175	173	173
Charles TS	211	145	150	153	154	154	155	155	156	155	157	159	160	161	167	168
Dufferin TS	170	136	119	122	123	123	123	124	124	126	129	130	133	136	144	148
Duplex TS	128	99	101	99	97	96	93	92	94	95	95	96	96	98	103	108
Esplanade TS	187	163	143	145	146	146	147	147	147	148	147	144	143	139	142	143
Gerrard TS	102	37	47	50	52	52	53	53	53	54	53	53	53	53	53	54
Glengrove TS	88	51	52	52	53	53	53	53	53	52	53	55	56	57	60	62
Main TS	77	60	61	61	62	63	63	62	63	63	65	65	66	66	67	67
Terauley TS	249	175	187	193	188	186	185	188	187	187	185	181	179	177	173	174
Manby E 115 kV																
Fairbank TS	182	171	150	158	162	167	171	173	173	174	175	176	176	175	179	184
Runnymede TS	219	96	63	115	157	156	158	157	160	159	161	161	162	164	170	178
Wiltshire TS	133	56	74	75	74	74	75	75	75	76	76	77	77	77	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	264	265	215	200	200	201	201	202	202	205	207	209	211	219	232
Strachan TS	169	139	143	144	145	146	145	147	146	147	151	155	158	161	174	184

(1) Non-coincident station peak, adjusted to extreme weather
(2) Load transferred to the new Horner TS DESN #2 in 2022



GTA North

REGIONAL INFRASTRUCTURE PLAN

October 22, 2020

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Prepared by:

Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Alectra Utilities Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Newmarket-Tay Power Distribution Ltd.
Toronto Hydro-Electric System Limited

DISCLAIMER

This Regional Infrastructure Plan (“RIP”) report was prepared for the purpose of developing an electricity infrastructure plan to address near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared (“the Intended Third Parties”), or to any other third party reading or receiving the RIP report (“the Other Third Parties”), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA NORTH REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of GTA North regional planning process, which follows the completion of the GTA North Integrated Regional Resource Plan ("IRRP") in February 2020 and the GTA North Region Needs Assessment ("NA") in March 2018. This RIP provides a consolidated summary of the needs and recommended plans for GTA North Region over the planning horizon (1 – 10 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Parkway belt switches at Grainger Jct. (completed in 2018)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purposes.

Table 1. Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other long term needs/options identified in Section 6.4 will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION BETWEEN 2020 AND 2030.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Alectra, Hydro One Distribution, the Independent Electricity System Operator ("IESO"), Newmarket-Tay Power Distribution Ltd. ("NTPDL") and Toronto Hydro-Electric System Limited ("THESL") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, sixteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

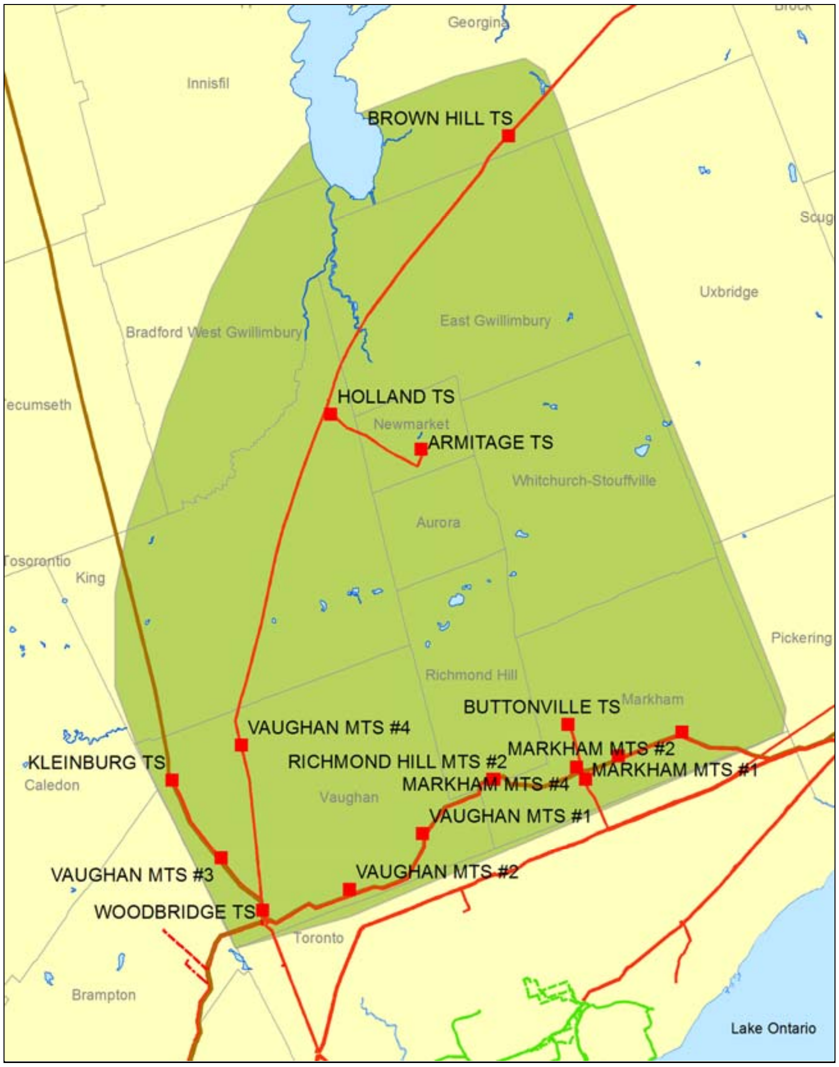


Figure 1-1: GTA North Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the GTA North Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs, as appropriate;
- Provide the status of wires planning projects currently underway or completed for specific needs; identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near, mid and long-term needs as identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and a plan to address them, as appropriate.
- Consideration of long-term needs identified in the York Region IRRP.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by Hydro One and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in Hydro One's rate filing submissions and as part of LDC rate applications with a planning status letter provided by Hydro One.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

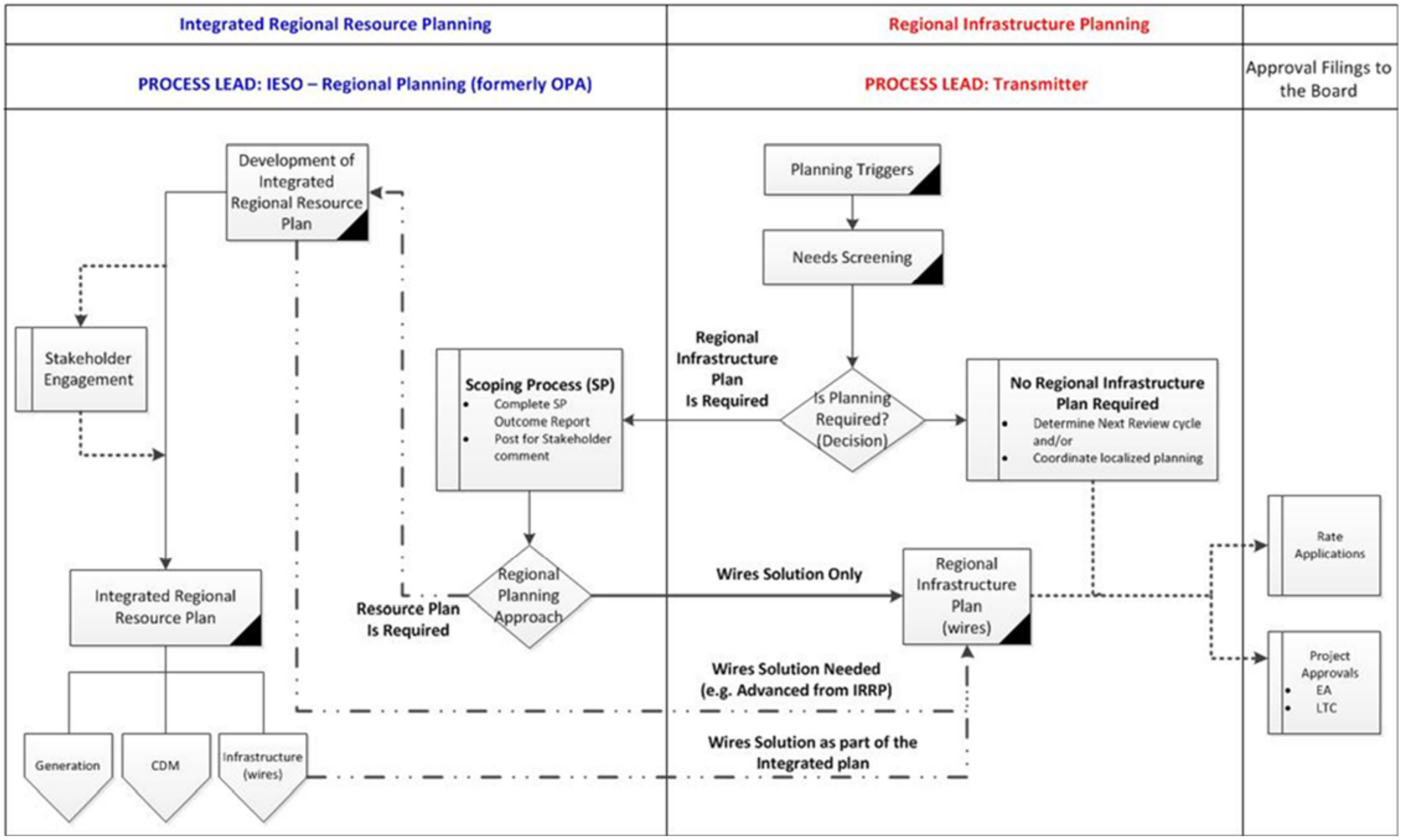


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other

relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

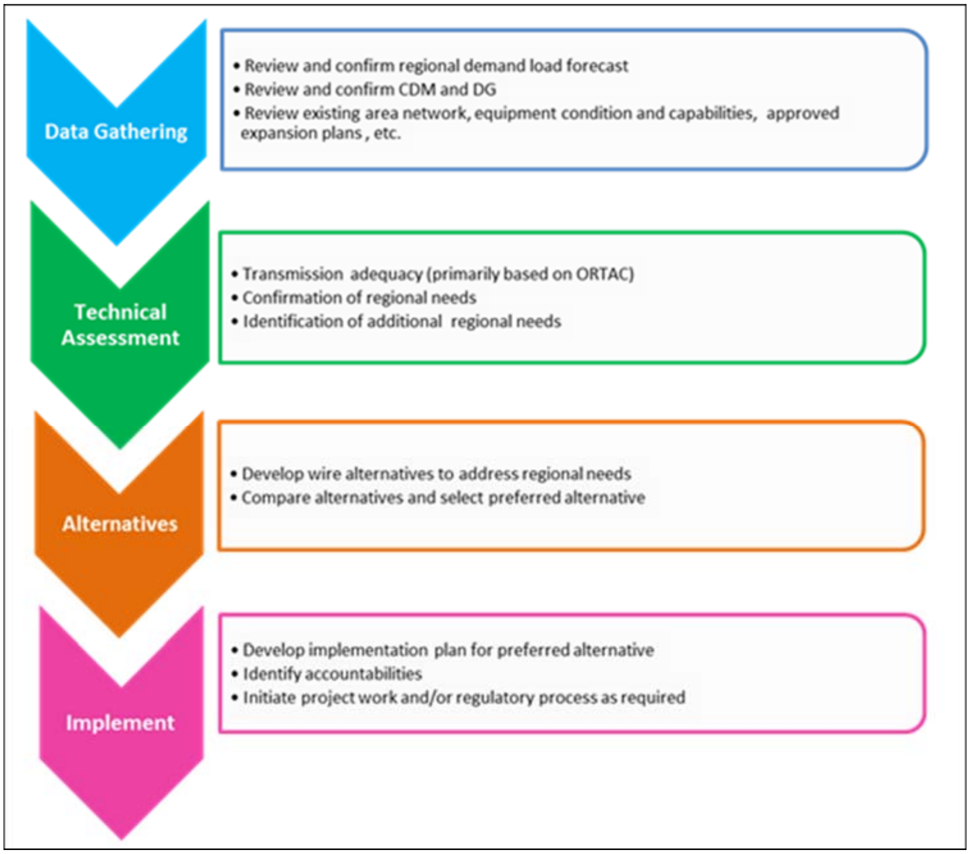


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE NORTHERN YORK AREA, SOUTHERN YORK AREA AND THE WESTERN AREA. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM SIXTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2019 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 2000 MW.

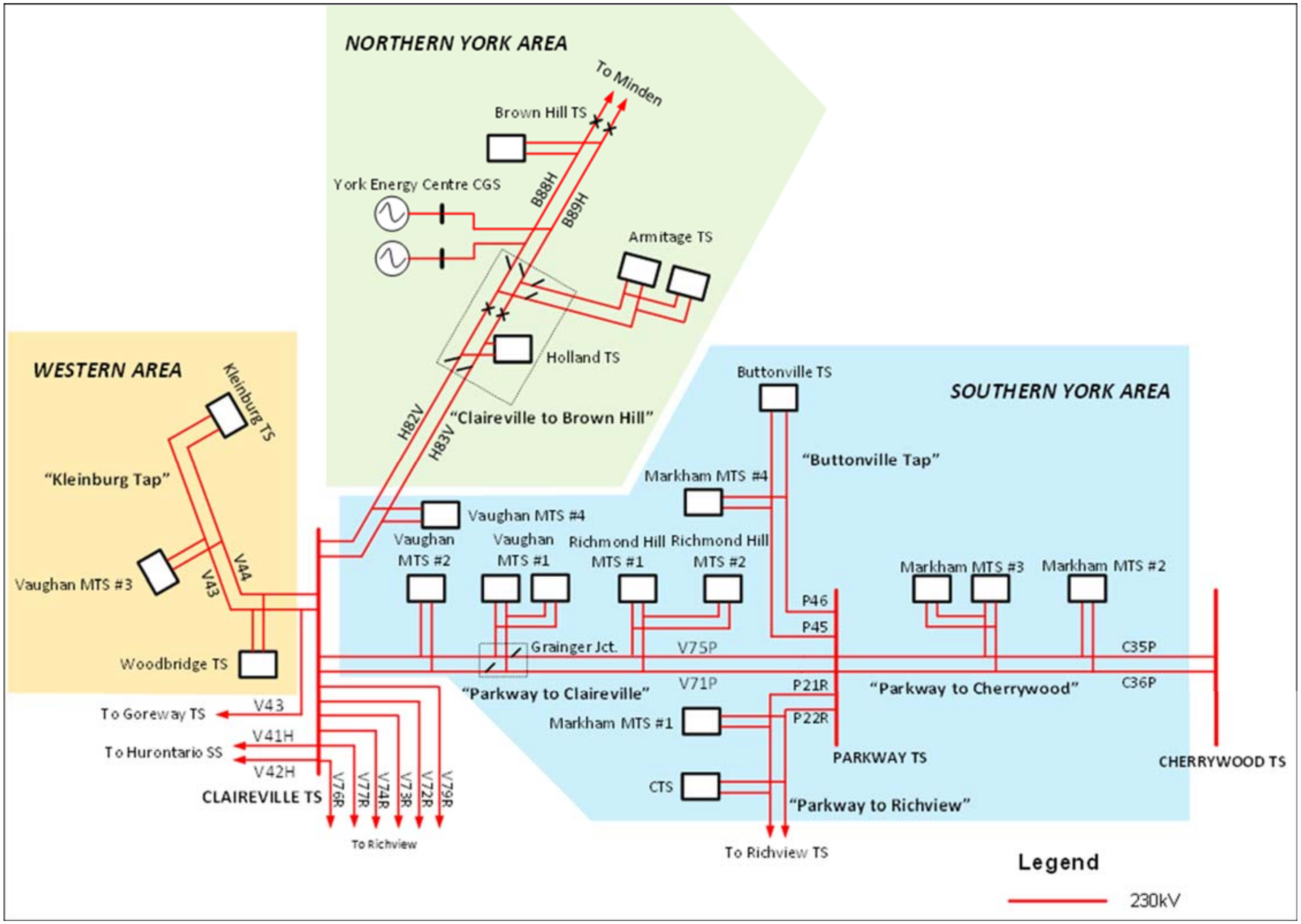
Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Refer to Appendix A, Appendix B and Appendix C for further details.

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and four 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes seven municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is Alectra. Please refer to Figure 3-1.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the “Kleinburg tap”) that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro. Please refer to Figure 3-1

Figure 3-1: Single Line Diagram of GTA North Region's Transmission Network



4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE GTA NORTH REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.

- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.

- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the Northern York area.

- Inline switches on the Parkway belt (V71P/V75P) at Grainger Jct. (2018)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of about 2% annually from 2020 to 2030, with average rate of about 2.5% between 2020 and 2025 and about 1.50% between 2025 and 2030.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast ("load forecast"). The load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

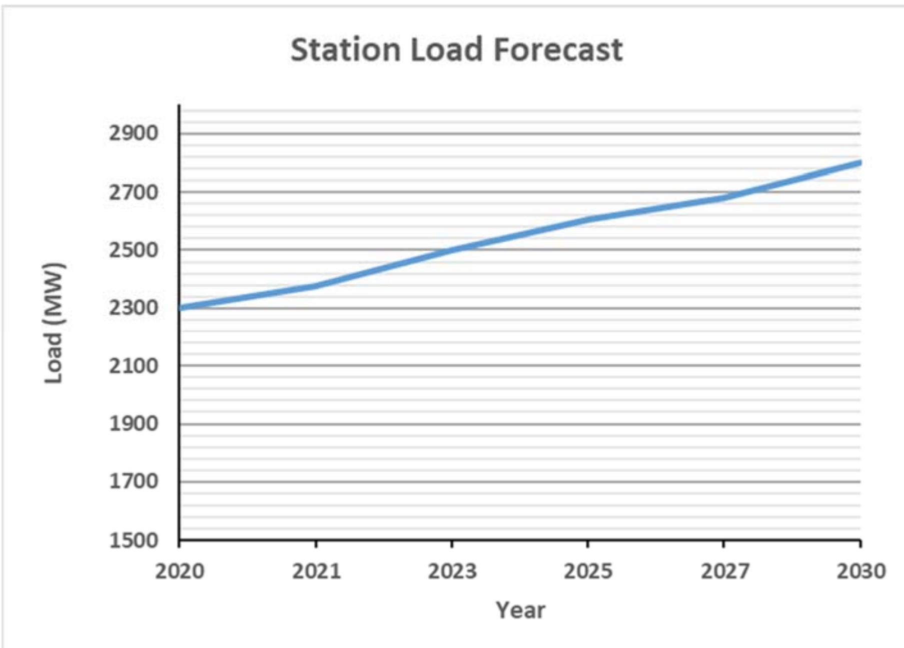


Figure 5-1: GTA North Region Load Forecast

The station coincident peak net loads used in the RIP are consistent with the York Region IRRP. However, as a result of the COVID-19 pandemic, this forecast may require review and updates as the long term impacts on customer demand become better known. The Study Team will be monitoring actual loading in York areas over the coming years and will recommend if updates to need dates or a revised forecast is required. However, based on the available information any change is not expected to materially impact any of the needs identified, but the dates to implement solutions may be affected.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for this RIP is established from 2020-2030.

- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations, which is consistent with Ontario Resource Transmission Assessment Criteria (ORTAC). Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using peak loads in the area.

6 ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE GTA NORTH REGION OVER THE PLANNING PERIOD (2020-2030).

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2018 GTA North Region Needs Assessment Report ("NA")
- 2018 York Region Scoping Assessment Outcome Report ("SA")
- 2020 York Region Integrated Regional Resource Plan and Appendices ("IRRP")

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region based on the forecast in Appendix D.

6.1 Adequacy of Northern and Southern York Area Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 3-1.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS ("Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

The RIP review shows that based on current forecast station loadings and bulk transfers, circuits P45 and P46 need to be uprated due to the future connection of Markham MTS #5. The other 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of thirteen step-down transformers stations in the Northern and Southern York Areas as follows in Table 6-1 Step-Down Transformer Stations below:

Table 6-1 Step-Down Transformer Stations

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1*	Markham MTS #2*
Markham MTS #3*	Markham MTS #4*	Richmond Hill MTS #1, #2*
Vaughan MTS #1*	Vaughan MTS #2*	Vaughan MTS #4*
Industrial Customer		

*Stations owned by Alectra

Based on the LTR of these load stations, additional capacity was required in Vaughan and was addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2025, and additional capacity will be needed in Northern York Area and Vaughan as early as 2027 and 2030, respectively. The station loading in each area and the associated station capacity and need dates are summarized in Table 6-2**.**

Table 6-2 Adequacy of the Step-Down Transformation Facilities

Area/Supply	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Markham / Richmond Hill transformation Capacity	957	877	2025
Northern York Area (Armitage TS, Holland TS)	485	444	2027
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	461	2030
Northern York Area (Brown Hill)	184	94	-

6.2 Adequacy of Western Area Facilities

6.2.1 230 kV Transmission Facilities

The Western Area is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-1. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.2 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the Western Area as follows:

Table 6-3 Step-Down Transformation Facilities in the Western Area

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by Alectra

The load forecast in Table 6-4 shows that there is adequate transformation capacity available at these three transformer stations to meet GTA North demand over the study period. Note that these facilities also serve load in the neighbouring GTA West Region. An IRRP is currently underway to determine long term infrastructure needs to serve GTA West, which may affect this region.

Table 6-4 Adequacy of Step-Down Transformation Facilities in the Western Area

	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Western Area	509	425	Beyond 2030

6.3 Other Needs Identified During Regional Planning

6.3.1 Load Restoration in the Western Area

There is a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.1.

6.3.2 Load Restoration in the Northern York Area

There is a load restoration need for the loss of the Claireville to Holland double circuit line, H82V/H83V. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.2.

6.3.3 Load Security and Restoration in the Southern York Area

There is a load security need for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on this line exceeds the 600 MW limit as per ORTAC security criteria. The Study Team recommendations to address the needs are discussed in more detail in Section 7.5.

6.3.4 High Voltages on Circuits M80B/ M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially connected to Minden TS. The Study Team recommendations to address the needs are discussed in more detail in Section 7.3.2.

6.3.5 End of Life of Woodbridge TS- Transformer-T5

Transformer T5 is currently about 47 years old and is approaching End of Life (EOL). This need is further discussed in Section 7.1.

6.4 Longer Term Regional Needs (2030-2040)

The IRRP considers longer-term needs and alternatives that are expected to occur between 2030 and 2040, which are outside the study period of the RIP. Table 6-5 summarizes the long term need for the Claireville to Minden circuits.

Table 6-5: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability (Approximate)	Need Date
	2025	2030	2035		
230 kV Claireville to Minden Circuits	727	765	943	850(2)	Beyond 2030

(1) The sum of station's (Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hills TS, Northern York TS, Vaughan#5 MTS excluding Beaverton TS and Lindsay TS) summer peak load adjusted for extreme weather.
(2) 2020 York Region IRRP. Actual capability is dependent on distribution of loads across stations and other system assumptions.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE GTA NORTH REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

The electrical infrastructure near and mid-term needs in the GTA North Region are summarized below in Table 7-1 and Table 7-2.

Table 7-1: Identified Near and Mid-Term Needs in the GTA North Region

Section	Facilities	Need	Details	Expected Timing
7.1	Woodbridge TS	End of Life (T5)	Transformer T5 is currently about 47 years old and is approaching End of Life (EOL)	2027
7.2.1	Markham# 5 MTS	Step Down Transformation Capacity	Loading at Markham & Richmond Hill area stations exceeded.	2025
7.2.2	Northern York TS		Loading at Armitage TS and Holland TS exceeded.t.	2027
7.2.3	Vaughan#5 MTS		Loading at Vaughan area stations exceeded.	2030
7.3.1	P45/P46 (Parkway TS to Markham #4 Jct.)	Supply Capability	Thermal limits are exceeded on a 1.1km section of the circuits between Parkway MTS and Markham #4 MTS due to the future connection of Markham MTS # 5.	2029
7.3.2	Claireville TS to Minden TS Corridor	Voltage Rise	Voltage rise on stations along M80B/M81B following loss of B88H/B89H	2025
7.4.1	Kleinburg radial pocket (V43/44)	Load Restoration	Restoration of loads supplied by V43/V44 does not meet the 30 minute load restoration criteria	Existing
7.4.2	H82V/H83V – Holland, Vaughan #4 and #5		Restoration of loads supplied by H82V/H83V does not meet the 30 minute load restoration requirement	Existing
7.5	Parkway TS to Claireville TS Circuits V71P/V75P	Load Security	Load security needs have previously been identified for the V71/75P Parkway corridor.	Existing

Table 7-2: Identified Long-Term Needs in GTA North Region

Section	Facilities	Need	Details	Timing
7.3.3	Claireville TS x Minden TS Corridor	Supply Capability	Thermal ratings & Voltage drop limits exceeded	Beyond 2030

7.1 Woodbridge TS: T5 End-of-Life Transformers

7.1.1 Description

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2019 actual peak load was 149 MW. Transformer T5 is currently about 47 years old and has been identified to be at its EOL.

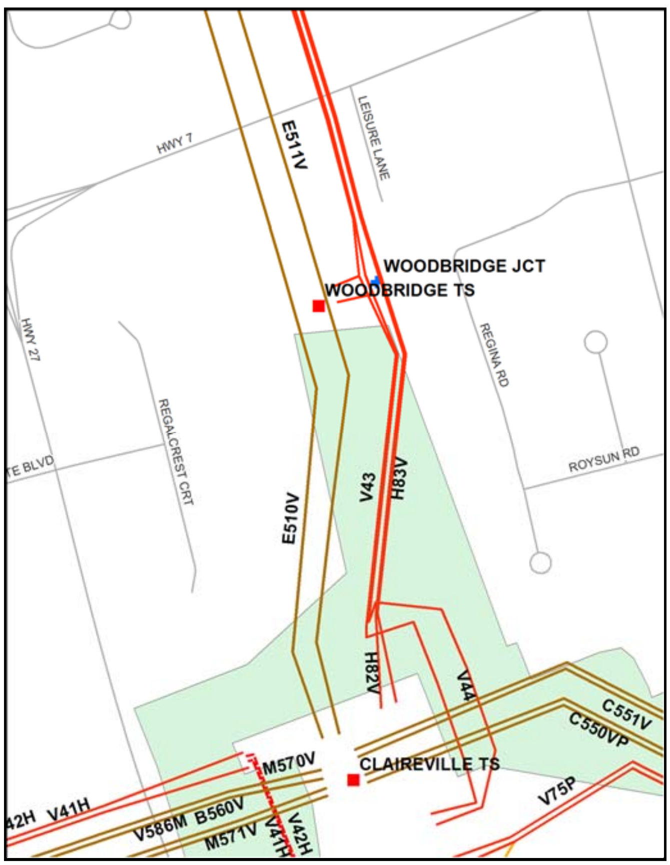


Figure 7-1: Woodbridge TS

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address the Woodbridge T5 end-of-life need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 – Re-configure Woodbridge TS as two separate 44 kV and 27.6 kV DESNs:** Hydro One has not considered this option further since there is currently no need for the additional transformation capacity, and there are limitations on the high voltage supply circuits. The cost of rebuilding the station would also be high.

The Study Team recommends that Hydro One proceed with Alternative 2 and coordinate the replacement plan with affected LDCs. The expected completion date for this work is 2027.

7.2 Station Supply Capacity Needs and Plans

Needs assessment and IRRP have identified three new station capacity needs in the medium term, one in the Markham –Richmond Hill region, designated as Markham MTS#5, the second in the Vaughan Area, designated as Vaughan MTS#5 and third in the Northern York Area, location and designation to be determined. The timelines associated with these needs require all the stakeholders to monitor station loadings and ascertain pace of the growth including energy efficiency (EE) and other Distributed Energy Resource (DER) impacts. Below are the options for the above needs to finalize the suitable location and explore the long-term options.

7.2.1 Markham MTS #5 Transformer Station

In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station in the north Markham area. Based on the current load forecast, the additional transformation capacity is required by the year 2025.

7.2.1.1 Alternatives and Recommendation

Three alternative locations for connecting the new Markham MTS #5 have been considered by the Study Team and shown in Figure 7-2.

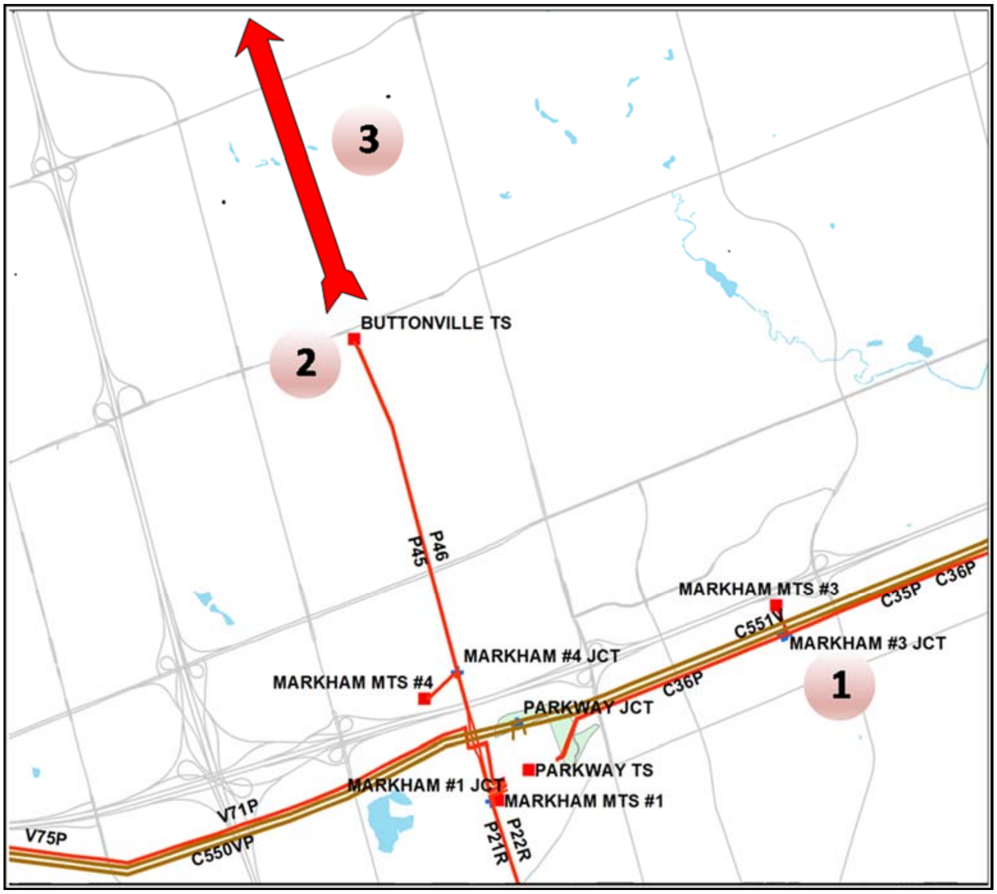


Figure 7-2: Location options for Markham #5 MTS

1- **Alternative 1- Building the new station along the Parkway belt and connecting to the C35P/ C36P circuits:** The C35P/C36P transmission circuits are capable of supplying the full capacity of the station, but the alternative has been ruled out because the physical location of the station would be too far from the area of anticipated growth resulting in high distribution costs. There is also a risk that the capacity of this station will become stranded if it becomes technically infeasible to supply load concentrated along Markham's northern border

2- **Alternative 2- Building the station at the existing Buttonville TS and connecting to the P45/P46 circuits:** This alternative is closer to the area of anticipated load growth than alternative 1, and lesser distribution infrastructure is required as compared to Alternative 1. A 1.1 km section between Parkway TS and the Markham MTS#4 Jct would need to be uprated.

3- **Alternative 3 - Building the station in north Markham and extending circuits P45/P46 from Buttonville TS to connect the new station:** This location is nearest to the area of anticipated load growth. However, this option requires rebuilding approximately 6 km of a single circuit 115 kV transmission line as a 230 kV double circuit transmission line. Most of the 6 km corridor is adjacent to residential areas and the previous plan to upgrade this infrastructure resulted in community opposition. It is likely that some portion of the transmission line would need to be undergrounded. A new station property would also need to be acquired.

Alternative 1 was not considered further due to the high distribution costs. Of the remaining two alternatives, the Study Team recommends Alternative 2 - building the new station at Buttonville TS. While the distribution costs are higher under this option, the higher costs of extending the transmission line north from Buttonville for Alternative 3, made these two alternatives comparable for the overhead option only. Alternative 2 was selected as the preferred option in response to community preferences.

Alectra will be building the station and Hydro One will be building the line tap connection from the P45/P46. The current planned in-service date for the new station is 2025.

7.2.2 Northern York Area Transformer Station

Additional step down transformation capacity is needed for the areas supplied by Armitage TS and Holland TS. There is transfer capability between these stations, so their combined LTR of 485 MW is used to determine the need. Based on the load forecast, it is expected that additional step down transformation capacity will be needed by 2027. Refer to Table 7-3 below.

Table 7-3: Northern York Area Peak Loading

Final Peak Demand Forecast, extreme weather by Station (MW)							
Station	**LTR (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Armitage	317	302	307	312	312	312	312
Holland	168	142	145	154	166	168	168
Northern York Area	153	0	0	0	0	12	32
Grand Total		**444**	**452**	**466**	**478**	**492**	**512**

7.2.2.1 Alternatives and Recommendation

It is anticipated that the new station will be supplied by circuits B88H/B89H which are in the vicinity of the forecasted load growth. Further discussions between Hydro One and the LDCs are recommended to determine the final location and connection point in order to meet an in-service date of 2027.

7.2.3 Vaughan Area Transformer Station

The Vaughan area station load in the Southern York Area is expected to increase from 461 MW in 2020 to 614 MW by 2030 exceeding the combined area stations capacity of 612 MW. Additional transformation capacity will therefore be needed in Vaughan by 2030. Alectra has sufficient space at Vaughan #4 MTS to accommodate another station there. However, there isn't sufficient transmission capacity available on the Claireville to Minden corridor to fully supply a second new transformation station, given that a new station in Northern York is anticipated by 2027. Therefore a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This is discussed further in Section 7.3.3.

7.2.3.1 Alternatives and Recommendation

The location chosen for and the land allocated to Vaughan MTS#4 is well suited to cater the load growth and provides enough land to build another step-down station. Building a new station at the same site would have an incremental cost of approximately $30 million.

7.3 System Capacity Needs and Plans

The Study Team has identified the following system capacity needs

7.3.1 Transmission Line uprate- P45/P46

The connection of the new Markham MTS#5 to the Parkway TS x Buttonville TS circuit P45/P46 circuits (see Figure 7-3 below) will increase the loading on these circuits. The forecast loading along with the long term emergency circuit rating is given in Table 7-4.

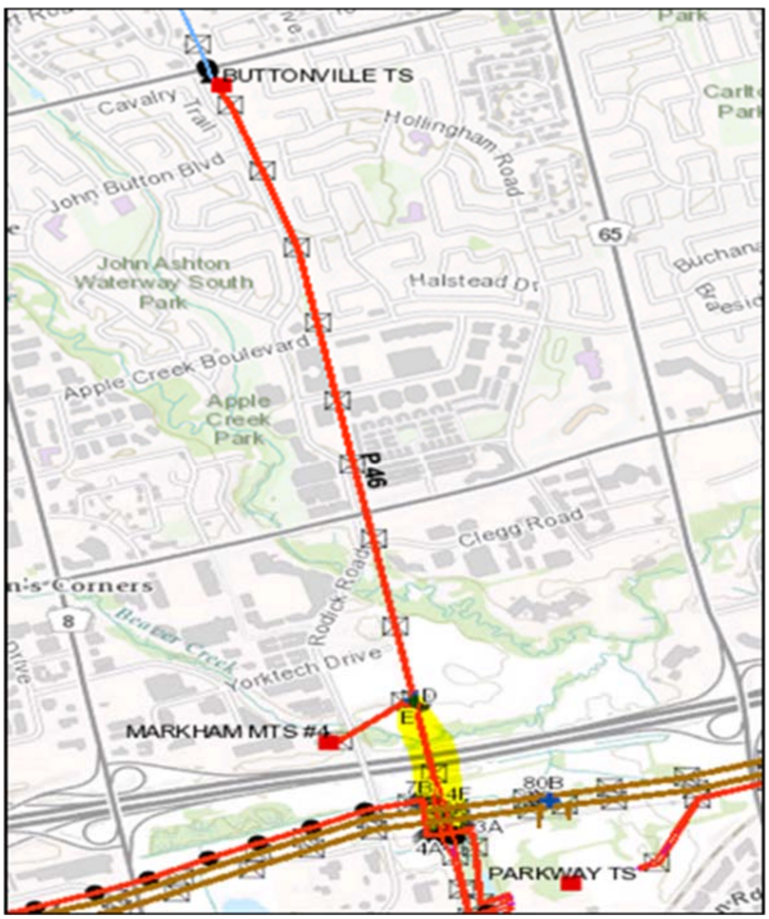


Figure 7-3: Buttonville Tap P45/P46 Limiting Section

The transmission capacity is thermally limited by an approximately 1.1 km long section between Parkway TS and Markham #4 Jct. Loading is expected to exceed the rating by 2029. This section will need to be uprated by 2029 to fully supply Markham MTS#5.

Table 7-4: Loading on Buttonville Tap Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)							
	Circuit Rating (MW)	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Buttonville TS		148	148	147	156	156	154
Markham MTS #4		99	128	153	153	153	153
Markham MTS #5		0	0	0	26	77	153
Grand Total	**420**	**247**	**276**	**300**	**335**	**386**	**460**

7.3.1.1 Alternatives and Recommendation

Two alternatives were considered to provide adequate capacity on the P45/P46 circuits.

1- **Alternative 1 - Increase thermal capability of existing line.** It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load on these circuits. A high level estimate for this work is $2-3 million.
2- **Alternative 2 – Reduce loading on the P45/P46 circuits by transferring Markham MTS#4 to the Cherrywood TS x Parkway TS C35P/C36P circuits:** This alternative frees up capacity on the P45/P46 circuits to supply MTS#5. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS#4 Jct to the C35P/C36P. This alternative was ruled out due to higher cost and greater disruption to the local community.

The Study Team recommends Alternative 1 as the technically preferred and most cost-effective alternative to increase the supply capability on P45/P46. It is also prudent to consider uprating these circuits before 2029 to reduce the amount of load at risk during construction outages. Completing this upgrade in time for the Markham MTS#5 in service date will also allow for the LDC to make full use of this facility's capacity to manage distribution operations including restoration, optimizing feeder loading, and accommodating maintenance.

7.3.2 High Voltages on M80B/M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially connected to Minden TS. These high voltages are observed when low voltage capacitor banks at Beaverton and Lindsay are dispatched under heavy load. In the long term, it is expected that infrastructure solutions required to meet anticipated post 2030 capacity needs will also address this need, though advancing this type of solution to address voltage needs is not recommended due to much lower cost and lower impact alternatives. The IRRP recommends identifying and implementing the solution not later than 2025 to mitigate the voltage rise issue.

7.3.2.1 Alternatives and Recommendations

Two alternatives were considered for the mitigation of the high voltages:

1- **Alternative 1 – Switch LV caps manually at Beaverton and Lindsay:** The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage (i.e. 262.5 kV) for up to 30 minutes. This capability provides sufficient time for operators to manually adjust the system. Under this alternative the operator will remotely switch out capacitor banks at Beaverton and Lindsay to mitigate high voltages when required.
2- **Alternative 2 - Expanding the York Region Special Protection Scheme (SPS):** The problem of overvoltage can be mitigated by modifying the York Region SPS to automatically remove capacitor banks at Lindsey TS and/or Beaverton TS under high load conditions following specific contingencies.

The Study Team agreed that Alternative 1 will meet the need as the system can withstand the expected voltages and manual action is adequate.

7.3.3 Long Term Need - Supply Capability of the Clairvelle TS to Minden TS Corridor

The Claireville-Minden corridor is comprised of three sections which are defined by inline breakers at Holland TS and Brown Hill TS:

- Section 1 - Claireville TS x Holland TS - H82V/H83V, supplying Holland TS and Vaughan MTS #4.
- Section 2 - Holland TS x Brown Hill TS - B88H/B89H, supplying Armitage TS and Brown Hill TS and connects the York Energy Centre generation. The station service supply to York Energy Centre is normally supplied by a distribution feeder from Holland TS.
- Section 3 - Brown Hill TS x Minden TS - M80B/M81B, supplying Beaverton TS and Lindsay TS. These two stations are not part of the GTA North Region.

The York Region SPS increases the load supply capability of the Claireville –Minden Circuits. The SPS enables controlled load rejection at Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hill TS following certain contingencies. The scheme can also reject generation at YEC, as required. The York Region SPS ensures that the transmission system does not get overloaded following certain contingences, consistent with ORTAC.

In the long term, the supply capability of the corridor is limited by both thermal and voltage capability of the transmission system. These needs arise after 2030 and consistent with the IRRP, the wires needs and alternatives identified are summarized below.

Thermal Limitations

The southern (Claireville TS x Brown Hill TS) section of the corridor supplies Vaughan MTS#4, Holland TS, Armitage TS and Brown Hill TS. Future proposed stations - Northern York area and Vaughan MTS#5 – will also be connected to this corridor. The forecast loading on the corridor is given in Table 7-5. Loading on the corridor will exceed its thermal limits of approximately 850 MW by about 2035.

Table 7-5: Loading on Claireville TS to Minden TS Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)								
Station	**Loading Limit (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**	**2035**
Armitage TS		302	307	312	312	312	312	312
Brown Hill TS		94	95	95	96	97	98	100
Holland TS		142	145	154	166	168	168	168
Northern York Area TS		0	0	0	0	12	32	62
Vaughan MTS #4		54	63	108	153	153	153	153
Vaughan MTS#5		0	0	0	0	0	2	147
Grand Total	**850**	**592**	**610**	**670**	**727**	**743**	**765**	**942**

Voltage Limitations

Post-contingency voltage drop will exceed ORTAC limits on the Claireville to Minden corridor after 2030. The limiting contingency is H82V/H83V which drops Holland TS, Vaughan #4 MTS and the future Vaughan #5 MTS by configuration. In addition, up to 150 MW of load rejection is permitted by ORTAC. YEC station service is normally supplied from Holland TS, so the generation is lost coincident with the contingency.

7.3.3.1 Alternatives and Recommendations

The IRRP includes two alternatives to deal with long term needs:

- New Line between Kleinberg TS and Kirby Jct.
- New Line between Buttonville TS and Armitage TS.

The Study Team agrees that the preferred plan will be developed during the next planning cycle as the need date is beyond 2030.

7.4 Load Restoration

Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability. The load restoration criteria is defined in ORTAC and summarized in Figure 7-4.

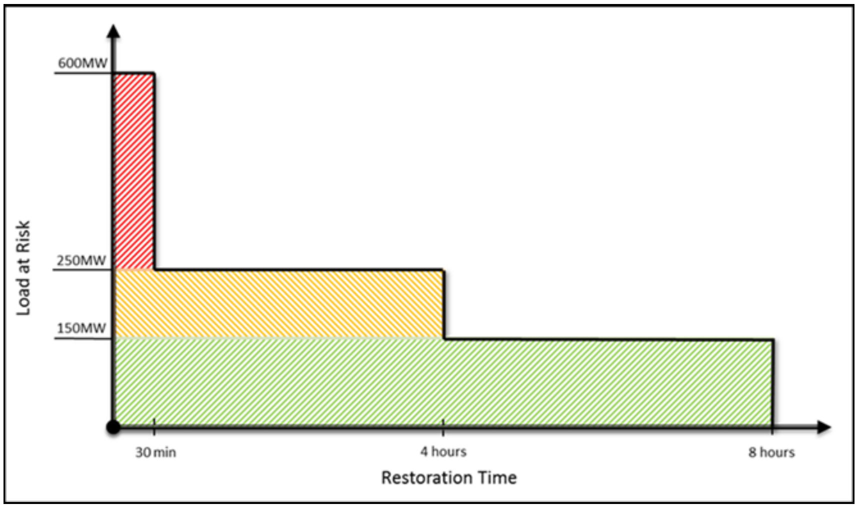


Figure 7-4: Load Restoration Criteria as per ORTAC

There is less risk of violation of ORTAC load restoration criteria especially within the municipalities of Vaughan, Markham, and Richmond Hill due to the availability of transfer capability between adjacent service territories. The Northern York and Western areas are prone to restoration risks which include the service areas served by Holland TS, Armitage TS, and Brown Hill TS and also in the Kleinburg TS area.

7.4.1 Load Restoration on Kleinburg Radial Tap (V43/44)

Load restoration was assessed for 230 kV radial double circuit line V43/V44 supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS that primarily supply rural and urban communities in Vaughan and Caledon and, to a lesser degree, Brampton, Mississauga and Toronto. In case of a double circuit outage of the V43/V44 line, not all loads in excess of 250 MW can be restored within 30 minutes, as per the ORTAC restoration criteria. The V43/V44 line is approximately 12 km long with good accessibility by maintenance crews and Hydro One expects all load to be restored within 4 hours with at least one circuit back into service.

Table 7-6: Load Restoration on Kleinburg Radial Tap

V43/V44-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Interrupted Load		426	436	444	449	453	450	453	454	455	456	475
Remaining after 30 minutes	250	347	357	366	370	355	352	356	357	358	359	376
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

7.4.1.1 Alternatives and Recommendations

The Study Team agreed that no further action is required at this time. However the need will be reviewed in the next iteration of the regional planning cycle. The historical reliability of these circuits has been good with no coincident outages of the two circuits; there have only been two direct outages[2] to circuit V43 since 2008 and no direct outages to circuit V44 since 2009. While there are no short term plans to address this need, the Kleinburg to Kirby option to address supply capacity needs in the long term would also improve the load restoration capability for these circuits. Based on the long term forecast the supply capacity needs will arise between 2030 and 2035. This alternative is discussed in further detail in Section 7.3.3. Until such time as a preferred long term solution is identified for the Claireville to Minden corridor, there is no need to pursue other alternatives.

7.4.2 Load Restoration on Claireville TS to Holland TS circuits (H82V/H83V)

Load restoration was assessed for 230 kV circuits H82V/H83V supplying Vaughan #4 MTS and Holland TS. In case of a double circuit outage of H82V/H83V, not all loads exceeding 250 MW can be restored within 30 minutes per the ORTAC criteria. However, Hydro One expects all loads to be restored within 4 hours with one circuit back in service. Refer to Table 7-7.

Table 7-7: Load Restoration on Claireville TS to Holland TS circuit (H82V/H83V)

H82V/H83V-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load loss by configuration		196	208	225	262	300	319	321	321	321	320	323
Load loss by SPS		90	96	101	101	101	101	106	113	120	126	132
Total Interrupted Load		286	304	326	363	401	420	427	434	441	447	456
Remaining after 30 minutes	250	250	268	290	327	347	366	373	380	387	393	402
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

[2] A direct outage is reported whenever a major component is in the outage state due to a condition or equipment failure directly associated with it.

7.4.2.1 Alternatives and Recommendations

Following the loss of H82V/H83V, the normal station service supply to YEC generation will also be lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. Therefore the Study Team recommends that the IESO identify and consider the possibility of a new station service supply arrangement at YEC to enable faster restoration of load on H82V/H83V, consistent with the load restoration criteria.

7.5 Improve Load Security on the Parkway to Claireville Line

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. The load security criteria in ORTAC limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.

7.5.1 Alternatives and Recommendations

The previous RIP recommended the installation of inline switches on the V71P/V75P circuits at the Vaughan MTS #1 junction to improve load restoration capability following loss of both V71P/V75P circuits. The switches do not reduce the amount of load that is interrupted, however the project enables Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously.

Hydro One completed this project in 2018 at a cost of $5.1 million.

The Study Team accepts that the load security criteria is not met, but agrees that no further action is required at this time since the switches permit quick restoration of the load.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13M
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] GTA North Regional Infrastructure Plan – February 2016

[2] GTA North Needs Assessment – March 2018

[3] York Region Scoping Assessment Outcome Report - 2018

[4] Integrated Regional Resource Plan (IRRP) - February, 2020

[5] Integrated Regional Resource Plan (IRRP) - Appendices - March, 2020

[6] IESO Ontario Resource Transmission Assessment Criteria (ORTAC)

10 APPENDIX A. STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
Kleinburg TS T1/T2 44	230/44	V44/V43
Vaughan MTS #3 T1/T2	230/27.6	V44/V43
Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
Woodbridge TS T3/T5 44	230/44	V44/V43
Armitage TS T1/T2	230/44	B88H/B89H
Armitage TS T3/T4	230/44	B88H/B89H
Brown Hill TS T1/T2	230/44	B88H/B89H
Holland TS T1/T2, T3/T4	230/44	H82V/H83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Markham MTS #2 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T3/T4	230/27.6	C35P/C36P
Markham MTS #4 T1/T2	230/27.6	P45/P46
CTS	230/13.8	P21R/P22R
Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V

11 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

12 APPENDIX C. DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Armitage TS	Tx/Dx
	Buttonville TS	Tx
	Holland TS	Dx
	Kleinburg TS	Tx
	Markham MTS #1	Tx
	Markham MTS #2	Tx
	Markham MTS #3	Tx
	Markham MTS #4	Tx
	Richmond Hill MTS #1	Tx
	Richmond Hill MTS #2	Tx
	Vaughan MTS #1	Tx
	Vaughan MTS #2	Tx
	Vaughan MTS #3	Tx
	Vaughan MTS #4	Tx
	Woodbridge TS	Tx/Dx
Distributor Name	**Station Name**	**Connection Type**
Newmarket-Tay Power Distribution Ltd	Armitage TS	Tx/Dx
	Holland TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Hydro One Distribution	Armitage TS	Tx
	Brown Hill TS	Tx
	Holland TS	Tx
	Kleinburg TS	Tx
	Woodbridge TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Toronto Hydro Electric System Limited	Woodbridge TS	Dx

13 APPENDIX D. GTA NORTH REGION LOAD FORECAST

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Armitage	317	302	307	312	312	312	312	312
Brown Hill	184	94	95	95	96	97	98	100
Northern York Area	153	0	0	0	0	12	32	62
B88H/B89H Total		396	402	407	408	421	442	474
Holland	168	142	145	154	166	168	168	168
H82V/H83V Total	168	142	145	154	166	168	168	168
Northern York Area Sub-Total		**538**	**547**	**561**	**574**	**589**	**610**	**642**
Markham #2	101	101	101	101	101	101	101	101
Markham #3	202	202	202	202	202	202	202	202
C35P/C36P Total		303	303	303	303	303	303	303
Markham #1	81	81	81	81	81	81	81	81
P21R/P22R Total		81	81	81	81	81	81	81
Buttonville	166	148	148	147	156	156	156	154
Markham #4	153	99	128	153	153	153	153	153
Markham #5	153	0	0	0	26	77	153	153
P45/P46 Total		247	276	300	335	386	462	460
Richmond Hill	254	246	246	245	250	254	254	254
Vaughan #1	306	265	275	300	306	306	306	306
Vaughan #2	153	142	151	153	153	153	153	153
V71P/V75P Total		653	672	698	709	713	713	713
Vaughan #4	153	54	63	108	153	153	153	153
Vaughan #5	153	0	0	0	0	0	2	147
H82V/H83V Total		54	63	108	153	153	155	300
Southern York Area Sub-Total		**1338**	**1395**	**1490**	**1581**	**1636**	**1714**	**1857**

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Kleinburg	196	144	145	146	147	148	169	170
Vaughan #3	153	132	141	153	153	153	153	153
Woodbridge	160	149	149	150	150	153	154	153
V43/V44 Total		425	435	449	450	454	476	476
Western Area Sub-Total		**425**	**435**	**449**	**450**	**454**	**476**	**476**
GTA North Region Total		**2301**	**2377**	**2500**	**2605**	**2679**	**2800**	**2975**

Toronto Region:

Integrated Regional Resource Plan

August 9, 2019

Connecting Today.
Powering Tomorrow.

Toronto Region
Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board license, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Toronto Regional Planning Working Group (Working Group), which included the following members:

- Independent Electricity System Operator
- Toronto Hydro-Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Hydro One)

The Working Group developed a plan that considers the potential for long term electricity demand growth and varying supply conditions in the Toronto region, and maintains the flexibility to accommodate changes to key conditions over time.

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Appendix B: Peak Demand Outlook for Toronto 2017-2041

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Appendix G: Responses to Public Feedback on Proposed Recommendations

List of Acronyms

Acronym/ Alternative	Description
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GTA	Greater Toronto Area
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long-term Emergency Rating
LTR	Limited Time Rating
MVA	Mega Volt Ampere
MW	Megawatt
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PV	Photo-voltaic (Solar)
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SS	Switching Station

Acronym/ Alternative	Description
STE	Short-term Emergency Rating
Toronto Hydro	Toronto Hydro-Electric System Limited
TPSS	Traction Power Sub-station
TS	Transmission Station or Transformer Station
Working Group	Technical Working Group for Toronto Region IRRP

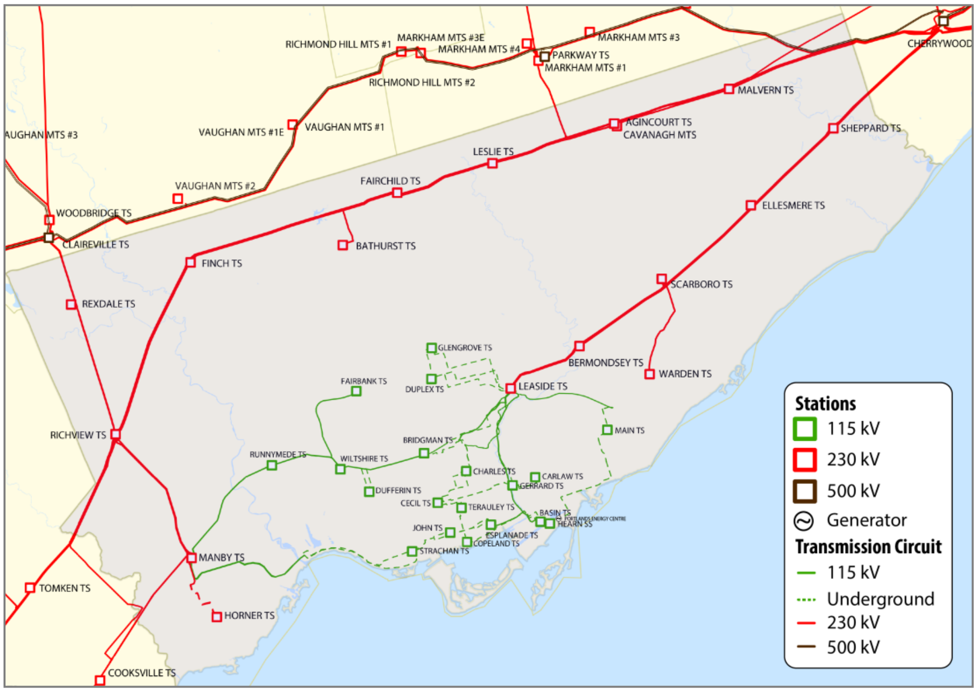
1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the regional electricity needs for the City of Toronto (Toronto region) between 2019 and 2040.[1] This report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group comprising the IESO, Toronto Hydro-Electric System Limited (Toronto Hydro), and Hydro One Networks Inc. (Hydro One).

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The Toronto region, shown in Figure 1-1, corresponds with the municipal boundaries of the City of Toronto. Other electricity planning regions adjacent to the Toronto region include Greater Toronto Area (GTA) West, GTA East, and GTA North.

[1] The planning horizon year is 2040: the different time frames within the plan period include the near term (up to five years out); medium term (six to 10 years out); and long term (11 to 20 years out).

Figure 1-1: Location of the Toronto Region



This IRRP reaffirms the needs and plans previously identified in the Metro Toronto Regional Infrastructure Plan (RIP) published in January 2016, and the Needs Assessment report completed in 2017. It identifies new capacity and reliability needs of the electric transmission system, and recommends approaches to ensure that Toronto's electricity needs can be met over the planning horizon. Specifically, the plan recommends approaches for addressing a number of end of life asset replacement needs and potential longer-term capacity needs to accommodate growth and city development.

For needs that may emerge in the longer term (11 to 20 years out), the plan maintains flexibility for new solutions. As the long term needs highlighted by the technical studies are subject to uncertainty related to future electricity demand and technological change, this IRRP does not recommend specific investments to address them at this time.

The plan identifies some near term actions to monitor demand growth, explore possible long term solutions, engage with the community, and gather information to lay the groundwork for determining options for future analysis. The near term actions recommended are intended to be completed before the next regional planning cycle, scheduled for 2024 or sooner, depending on demand growth or other factors that could trigger early initiation of the next planning cycle.

This report is organized as follows:

- A summary of the recommended plan for the Toronto region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for regional electricity planning in the Toronto region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in the Toronto region are presented in Section 6;
- Options and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. Summary of the Recommended Plan

The recommendations in this IRRP are focused on replacement of assets at their end of life, and preparing to address local and regional capacity needs emerging in the longer term.

The successful implementation of the recommended actions summarized below is expected to address the region's electricity needs until at least the late 2020s.

2.1 The Plan

This plan re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address the region's transmission needs until at least the late 2020s or early 2030s.

The recommendations set forth in this plan are summarized as follows:

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

The Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

The Working Group recommends that Hydro One continue planning to replace the existing cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: The Working Group recommends that detailed planning for end of life of these assets continue, starting with the RIP.[2]

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires alternative (NWA) solutions to address the need.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

The Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the environmental assessment (EA).

Keep options available to address long term regional supply capacity needs

For the longer-term regional capacity needs, including the Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section, the Working Group recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to:

- Define and communicate, as soon as practicable, the longer-term capacity needs

[2] The RIP is described in Section 3.1.

- Identify opportunities for a range of cost-effective solutions, including NWAs such as DERs and energy efficiency
- Identify potential wires solutions and avoidable costs should these needs be deferred through NWAs

The information and insights developed through these activities will be used to inform the next regional planning cycle.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure in an area, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:
1) A needs assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A scoping assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and/or
4) An RIP led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix A: Overview of the Regional Planning Process.

3.2 Toronto Region Working Group and IRRP Development

Development of the Toronto region IRRP was initiated in late 2017 with the release of a needs assessment prepared by Hydro One on behalf of the Toronto Regional Planning Working Group comprised of the IESO, Toronto Hydro, Alectra Utilities, Veridian Connections (now elexicon energy) and Hydro One Distribution. The report identified transmission needs that may require coordinated planning in the Toronto region, with needs limited to the electrical system within the municipal boundaries of the City of Toronto.

Subsequent to the Needs Assessment Report, the IESO prepared a Scoping Assessment Outcome Report, which recommended that an IRRP be undertaken to address a number of needs, owing to the potential for coordinated solutions. No sub-regions were identified for the purpose of carrying out this IRRP. Given the location of the needs identified, the IRRP Working Group was determined at the scoping assessment stage to include the IESO, Toronto Hydro and Hydro One.[3]

In 2018, the Working Group began gathering data, conducting assessments to identify near term to long term needs in the area, and recommending actions to address Toronto's electricity transmission needs.

[3] Distribution system planning does not fall within the scope of a regional planning study, though regional plans may inform distribution system plans. Distribution system plans are undertaken by local distribution companies and reviewed and approved by the OEB under a separate process.

4. Background and Study Scope

This is the second cycle of regional planning for the Toronto region. When the OEB formalized the regional planning process in 2013, planning was already underway in the Central Toronto area, a sub-region of Toronto that includes the downtown core. As such, Central Toronto became one of the Group 1 planning regions, and the first to participate in the formalized regional planning process.

The first cycle of regional planning for the Toronto region was completed in January 2016 with the publication of Hydro One's RIP for the Central Toronto area. Subsequent to the completion of an IRRP for Central Toronto (in April 2015), the IESO published an update to the IRRP that accounted for plans to convert commuter heavy rail in the GTA from diesel to electric power.

The second cycle of regional planning for Toronto was initiated by Hydro One in mid-2017. Following publication of a needs assessment in October 2017, a scoping assessment, released in February 2018, identified a number of needs requiring further regional coordination, and recommended that an IRRP for the Toronto region be initiated. No sub-regions within Toronto were recommended for this IRRP.

Building on past regional studies and taking into account updates to activities, including investments in electricity infrastructure and Toronto Hydro's long term outlook for electricity, this IRRP focuses on:

- Identifying recommendations for replacing assets that are reaching end of life
- Supporting and enabling growth and planned urban development
- Maintaining a high level of reliability performance

To set the context for this IRRP, the scope of the planning study and the area's existing electricity system are described in Section 4.1.

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the regional electricity needs of the Toronto region. Guided by the principle of maintaining an adequate level of reliability performance as per the *Ontario Resource and Transmission Assessment Criteria* (ORTAC), this study recognizes the importance of electricity service to the functioning of a large urban centre. The Toronto Region Scoping Assessment Outcome Report established the objectives, scope, roles and responsibilities, and timelines for this IRRP. The plan considers the long term outlook for electricity peak demand, energy efficiency, and transmission system capability and transmission asset condition. Options for addressing needs also considered relevant transmission and distribution system projects and capabilities, community plans, and distributed energy resources (DERs).

The transmission facilities that were included in the scope of this study are presented in Table 4-1 (stations) and Table 4-2 (circuits).

Table 4-1: Summary of Station Facilities (230 kV and 115 kV)

Leaside 115 kV	Manby 115 kV	East 230 kV	North 230 kV	West 230 kV
Basin TS	Copeland TS	Bermondsey TS	Agincourt TS	Horner TS
Bridgman TS	Fairbanks TS	Ellesmere TS	Bathurst TS	Manby TS[3]
Carlaw TS	John TS	Leaside TS[4]	Cavanagh TS	Rexdale TS
Cecil TS	Runnymede TS	Scarboro TS	Fairchild TS	Richview TS
Charles TS	Strachan TS	Sheppard TS	Finch TS	
Dufferin TS	Wiltshire TS	Warden TS	Leslie TS	
Duplex TS			Malvern TS	
Esplanade TS				
Gerrard TS				
Glengrove TS				
Main TS				
Terauley TS				
Hearn SS[5]				

[4] Includes the step-down transformers and 230/115 kV autotransformers
[5] Hearn Switching Station (SS)

Table 4-2: Summary of Transmission Circuits (230 kV and 115 kV)

230 kV	115 kV	
C10A	C5E	K11W
C14L	C7E	K12W
C15L	D11J	K13J
C16L	D12J	K14J
C17L	D6Y	K1W
C20R	H10DE	K3W
C2L	H11L	K6J
C3L	H12P	L12C
C4R	H13P	L13W
R1K	H14P	L14W
R2K	H1L	L15
R13K	H2	L16D
R15K	H2JK	L18W
R24C	H3L	L2Y
K21C	H6LC	L4C
K23C	H7L	L5D
	H8LC	L9C
	H9DE	

Transmission supply is provided to Toronto Hydro from 35 step-down transformer stations that are supplied by transmission voltages operating at either 230 kV or 115 kV. Toronto Hydro delivers electricity from these transmission supply points to its customers through its own electricity distribution system. Eighteen 230 kV step-down transformer stations supply the eastern, western and northern parts of Toronto (18 of these stations supply 27.6 kV voltage and two also supply 13.8 kV electricity to the distribution system); and 17 115 kV step-down stations supply the Central Toronto area (15 at 13.8 kV and two at 27.6 kV on the distribution side). The supply to these central 115 kV stations comes from two 230 kV/115 kV autotransformer stations (Leaside TS and Manby TS). The Toronto region also includes the Portlands Energy Centre (PEC) connected to the 115 kV transmission system (within the Leaside TS sector). The PEC 550 MW combined-cycle power plant plays an important role locally, and for the provincial electricity system, in providing reliable capacity to meet electricity demand, as well as reactive power and voltage support. Hearn SS provides 115 kV switching facilities for the Leaside area and also connects PEC to this system.

The Toronto region and its transmission supply infrastructure are shown in Figure 4-1 (map) and Figure 4-2 (single line diagram). Transmission circuit nomenclature used throughout this report (e.g., H1L, H3L, etc.) can be referenced using the single line diagram.

Figure 4-1: The Regional Transmission System Supplying Toronto

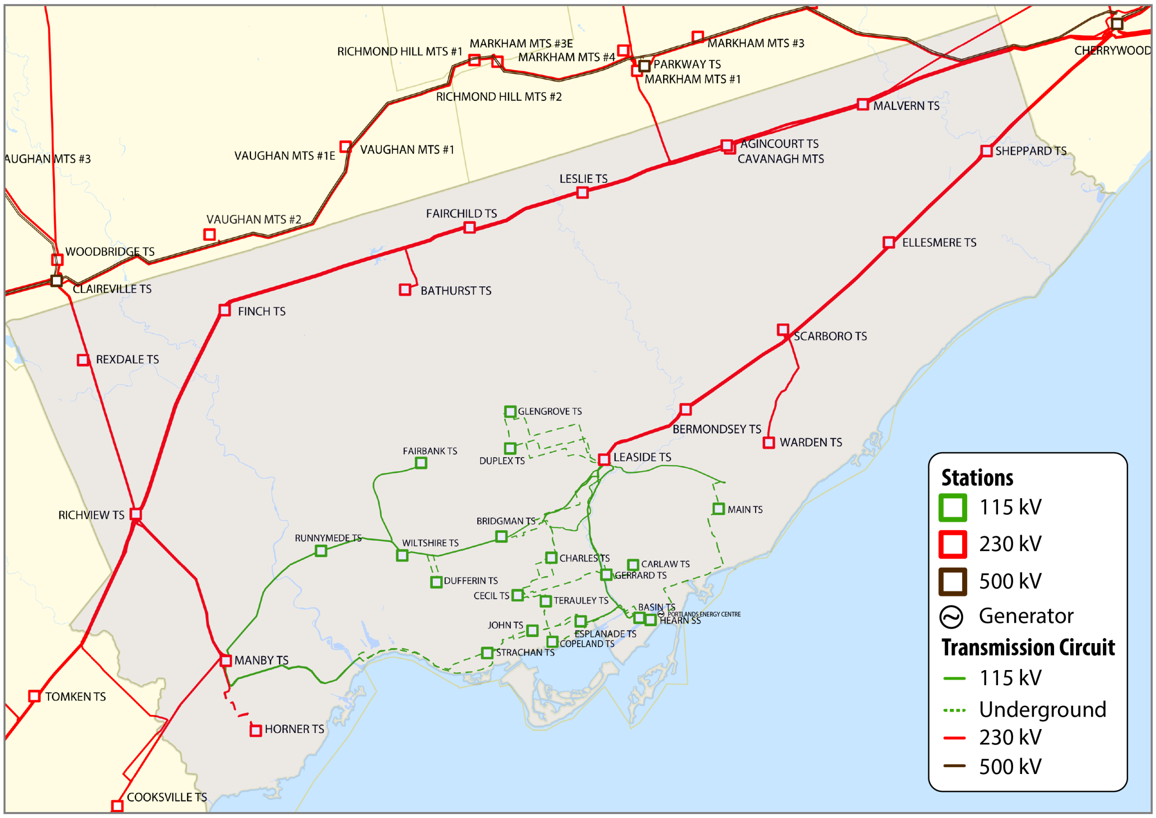
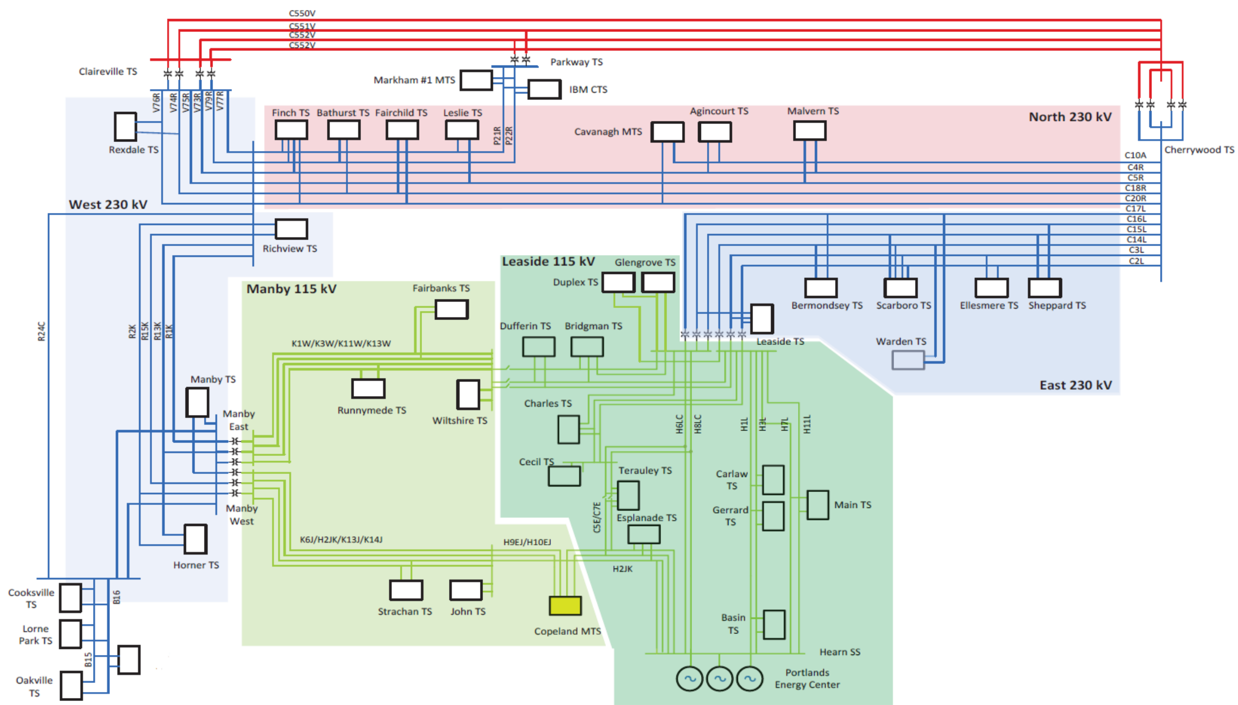


Figure 4-2: The Toronto Region Electrical System (Single-Line Diagram)



Completing the Toronto IRRP involved:

- Preparing a long term electricity peak demand outlook (forecast);
- Examining the load meeting capability and reliability of the transmission system supplying the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities (such as reactive power devices);
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end of life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as NWAs;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near and long term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Peak Demand Outlook

The electricity system needs that are in scope for regional planning are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak demand requirements (rather than energy demand requirements).[6] Peak demand requirements appearing at the station level are aggregated to understand the limits of the regional transmission system supplying the area as well as individual stations. Regional planning typically focuses on the regional-coincident peak demand to assess regional transmission needs, and individual station peaks to assess local transformer station capacity needs (the demand outlook is broken down spatially by transformer station, or each dual element spot network (DESN) that makes up a station[7]).

Individual stations within the Toronto study area typically experience peak loading at around the same time (e.g., weekdays, generally between 4 and 6 p.m. in summer, after consecutive hot days). There is also a high degree of coincidence between when individual stations peak and when the region peaks.

5.1 Demand Outlook Methodology

Toronto Hydro, in consultation with the Working Group, prepared a peak demand outlook at the transformer station bus level per IESO requirements for performing this study.

The outlook was developed in two parts:

1. Development of the Gross Peak Demand Outlook (Gross Outlook)
2. Development of the Net Peak Demand Outlook (Net Outlook)

The Gross Outlook recognizes the strengths of different forecasting methodologies for different time periods. The first 10 years is based upon the linear regression of past peak demands combined with known load additions and load redistributions. The period beyond 10 years is

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[6] Peak demand of the electric system is typically measured in terms of megawatts (MW) capacity; energy is the capacity needed over a period of time, for example, one megawatt used over one hour is a megawatt-hour (MWh).

[7] A DESN refers to a standard station layout, where two supply transformers are configured in parallel to supply one or two medium-voltage switchgear (for example, 13.8 kV or 27.6 kV), which the distributor uses to supply load customers. This parallel dual supply ensures reliability can be maintained in the event of an outage or planned maintenance. A single local transformer station can have one, two, or more individual DESNs.

based upon the growth rates predicted from an econometric model that takes population, employment, and long term weather into account.

The Gross Outlook is a "business-as-usual" peak demand forecast under extreme weather. The Net Outlook considers load drivers that are over and above those considered in the "business as usual" Gross Outlook. These "new and emerging" load drivers were:

- electric vehicles
- electrification of mass transit
- fuel switching from natural gas to electric for space heating and water heating
- energy storage

The result was a station-by-station outlook of annual peak demand through to 2041. More details may be found in Appendix B: Peak Demand Outlook for Toronto 2017-2041.

5.2 The Outlook for Energy Efficiency

The outlook for future peak demand savings is based on mandated efficiencies from Ontario building codes and equipment standards, which set minimum energy efficiency levels through codes and regulations. To estimate the impact of efficiency codes and standards in the Toronto region, the peak demand savings for the residential, commercial and industrial sectors were estimated at the provincial level, compared with Toronto's station-based peak demand forecast, and expressed as a percentage of peak demand offset on an annual basis. This estimation took into account the breakdown of the peak demand at the station of residential, commercial, and industrial sector demand. Estimated peak demand savings, in MW, were calculated based on the percentage demand offset and the Demand Outlook described in Section 5.1.

These savings were subtracted from the demand outlook, and this forecast with efficiency codes and standards was used to test the sensitivity of the need dates as identified by the Net Outlook described in Section 5.1.

Table 5-1 shows the total peak demand savings attributable to efficiency codes and standards for the Toronto area, for selected years within the planning horizon.

Table 5-1: Estimated Peak Demand Savings from Codes and Standards

Year	2020	2025	2030	2040
Estimated savings (MW)	86	159	242	311

Source: IESO

A more detailed methodology on the outlook for energy efficiency, including assumptions and a breakdown by station and year, is provided in Appendix C: Energy Efficiency Forecast.

5.3 Outlook for Distributed Energy Resources

In addition to energy efficiency, DERs in the Toronto region have previously offset, and are expected to continue to offset peak demand. Previous procurements, including the Feed-in Tariff (FIT) Program, have helped to increase the amount of renewable DERs in Toronto. Other competitive generation procurements have also resulted in additional DER types, such as combined heat and power (CHP) projects.[8] The DERs under contract with the IESO include a mix of solar photovoltaics (PV), CHP, and wind resources.

Further to these, competitive procurement pilots run by the IESO for energy storage resources have resulted in some energy storage projects in the region, and are supporting efforts to better understand the barriers related to integration of energy storage into Ontario's electricity market.

The peak demand impact of DERs that were connected to the system at the time the demand outlook was produced would be implicitly accounted for in the outlook. Given the difficulty of predicting where future DERs may be located, and uncertainty around future DER uptake, no further assumptions have been made regarding future DER growth. Instead of assuming future DER growth implicitly as a load modifier in the demand outlook, the potential of future DERs will be considered as potential solution options.

While the FIT Program and other competitive procurements for small-scale generation, including CHP, have ended, the IESO has been engaged in developing market-based mechanisms to enable a variety of electricity resources to compete in the electricity market. In addition, the IESO is engaged in several activities to enable DERs as alternatives to wires-based solutions. This includes working with other sector participants to identify and overcome

[8] Since the IRRP forecast was developed, contracts for some generators included in the 2017 list have been terminated.

barriers to DER participation and implementation, as many of the issues extend beyond the IESO's mandate.

The IESO's work and other electricity sector initiatives related to DER barriers are expected to inform ongoing discussions on possible future DER options in Toronto, as per the recommendations made in this IRRP.

6. Power System Needs

Based on the demand outlook, system capability, identified end of life asset replacement needs, and application of provincial planning criteria, the Working Group identified electricity needs in the Toronto region in the near, medium, and long term.

6.1 Needs Assessment Methodology

ORTAC,[9] the provincial criteria for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of both the bulk transmission system and local or regional reliability requirements. See Appendix D: Toronto IRRP Study Results, and Appendix E: Station Capacity Assessment, for more details.

In applying ORTAC, three broad categories of needs can be identified:

- **Local Capacity** describes the electricity transmission system's ability to deliver power to LDCs through regional step-down transformer stations. This is determined by the Limited Time Rating (LTR) of the station, which is typically determined by the rating of its smallest transformer(s), under the assumption that the largest transformer is out of service.[10]
- **Regional Capacity** is the electricity transmission system's ability to provide continuous supply to LDCs in a local area, which is limited by the load meeting capability (LMC) of the transmission facilities in the area. The LMC is determined by evaluating the maximum peak demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix D, Toronto IRRP Study Results, for more details). Regional capacity needs are identified when the peak demand for the area exceeds the LMC of regional transmission facilities.
- **Load Security and Restoration** is the electricity transmission system's ability to minimize the impact of potential supply interruptions in the event of a credible contingency (e.g., a transmission outage considered for planning purposes), such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security

[9] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

[10] A station's rating is determined by its most limiting component(s), which may not always be the transformer(s).

describes the maximum limit of load interruption that is permissible in the event of a transmission outage considered for planning. These limits reflect past planning practices in Ontario. Load restoration describes the electricity transmission system's ability to restore power to a transmission customer (e.g., LDC) affected by a transmission outage within specified time frames. Specific requirements can be found in ORTAC, Section 7, Load Security and Restoration Criteria.

The plan also identifies requirements related to the end of life of transmission assets. End-of-life asset replacement needs are identified by the transmitter based on a variety of factors, such as asset age, condition, expected service life, and risk associated with the failure of the asset. Replacement needs identified in the near and early medium term time frame typically reflect the assessed condition of the assets, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium term needs or those farther out reflect a potential for the need date to change based on priority and/or updates to asset condition.

6.2 Power System Needs

Through the planning studies for the Toronto IRRP, the Working Group identified four main categories of needs: (1) end of life asset replacement, (2) local transformer station capacity, (3) regional supply capacity, and (4) load security and restoration. In addition, pursuant to ORTAC provisions, maintaining a higher level of reliability performance (i.e., above the minimum standards) was also considered which identified some 'discretionary' reliability needs.[11] The specific needs under each of these categories are explained in the sections that follow.

6.2.1 End-of-life Asset Replacement Needs

Hydro One identified a number of end of life transmission asset replacement needs for the Toronto region in the needs assessment phase of this regional planning cycle, with several needs arising in the near to medium term.

[11] 'Discretionary' reliability needs are transmission system issues that are flagged through the application of a uniform set of planning criteria for all of Toronto's transmission system (e.g., by applying 'bulk power system' criteria to 'local area' facilities). This identifies issues that are discretionary in the sense that the reliability performance of the system complies with the criteria; but may represent opportunities to improve reliability to an area if cost-effective opportunities are available.

Since end of life needs are based on the best available asset condition information at a given point, the timing of asset replacement can change, as more recent asset condition results become available. If asset deterioration occurs faster than predicted, need dates may need to be advanced. As a result, the scope and timing of some of these needs have been updated since the needs and scoping assessments were completed.

6.2.1.1 Near-term Asset End-of-life Replacement Needs

Three near term asset end of life replacement needs were addressed within the scope of this plan (Table 6-1). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

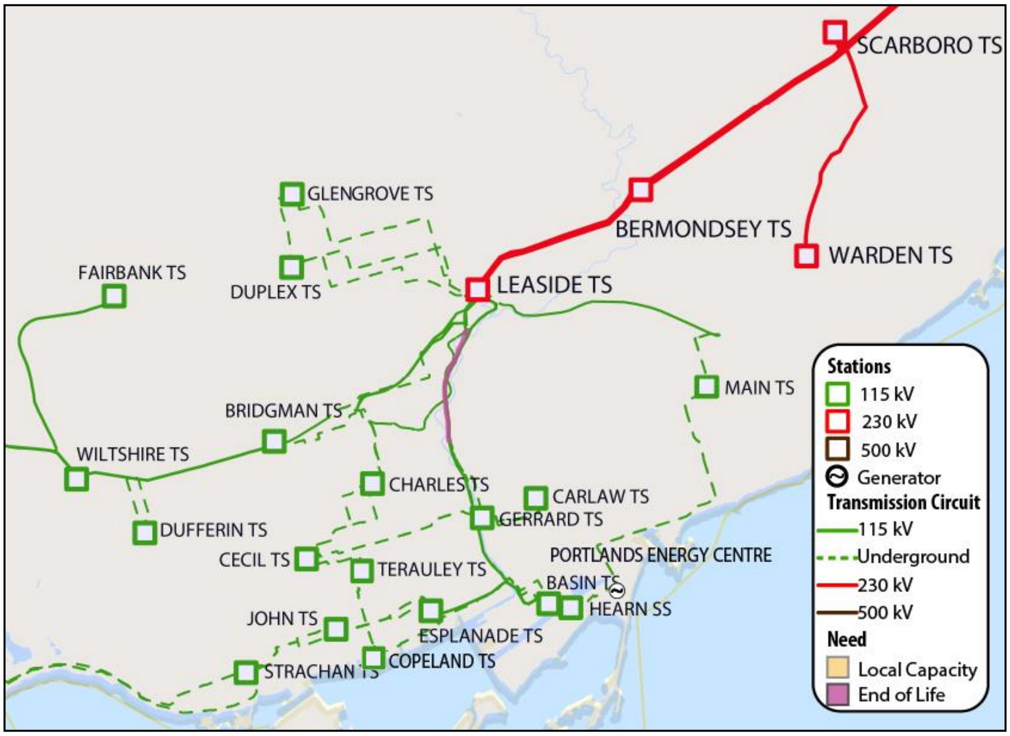
Table 6-1: Toronto Region End-of-life Asset Replacement Needs (Near term)

Facilities	Need	Expected Timing
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2-km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6-km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022

Leaside to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)

The 115 kV overhead transmission lines H1L, H3L, H6LC, and H8LC provide supply to the eastern part of central Toronto from Leaside TS. The end of life part of the line is a 2-km section that runs from Leaside Junction to Bloor Street Junction in the Don Valley, and is on a common tower with four circuits (Figure 6-1). Hydro One has determined the conductors are reaching the end of their useful life, and will need to be replaced by 2022-2023 to maintain safety and reliability.

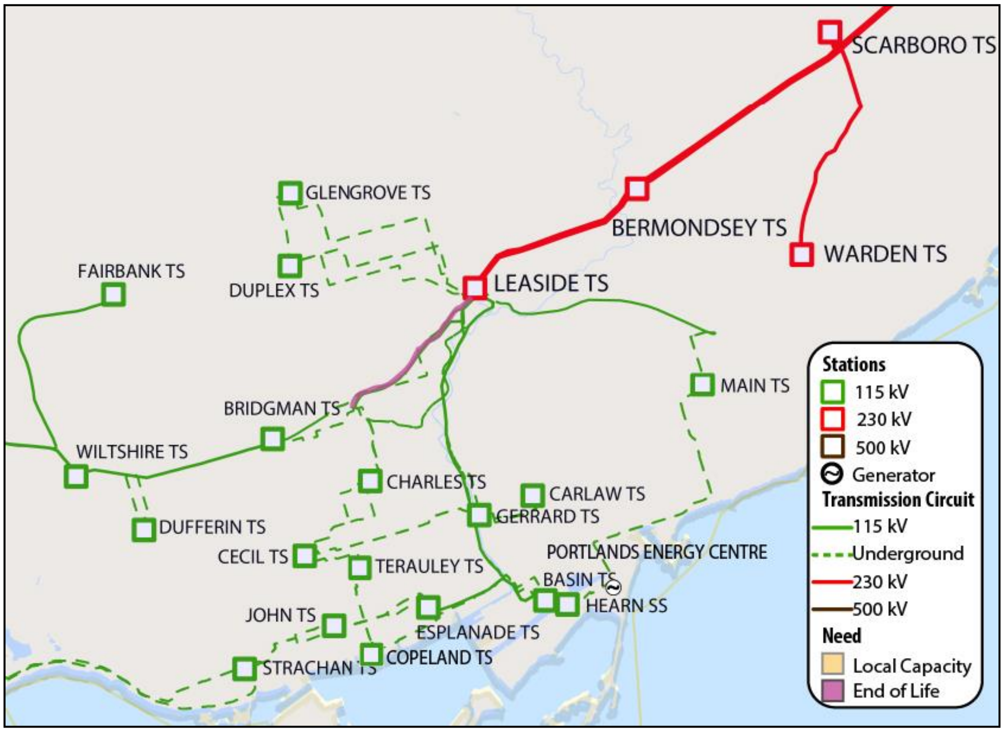
Figure 6-1: Leaside to Bloor Street Junction 115 kV Overhead Transmission Lines



Leaside to Balfour 115kV overhead transmission lines (L9C/L12C)

The 115 kV overhead transmission lines L9C and L12C provide supply to central Toronto from Leaside TS (to Cecil TS). The section of the line that runs between Leaside TS and Balfour Junction is about 3.6 km in length, and runs through the Don Valley and along an existing rail corridor (Figure 6-2). This line is more than 80 years old and the conductors have been identified by Hydro One as reaching the end of their useful life, and requiring replacement by 2023-2024 to maintain safety and reliability.

Figure 6-2: Leaside to Balfour 115kV Overhead Transmission Lines



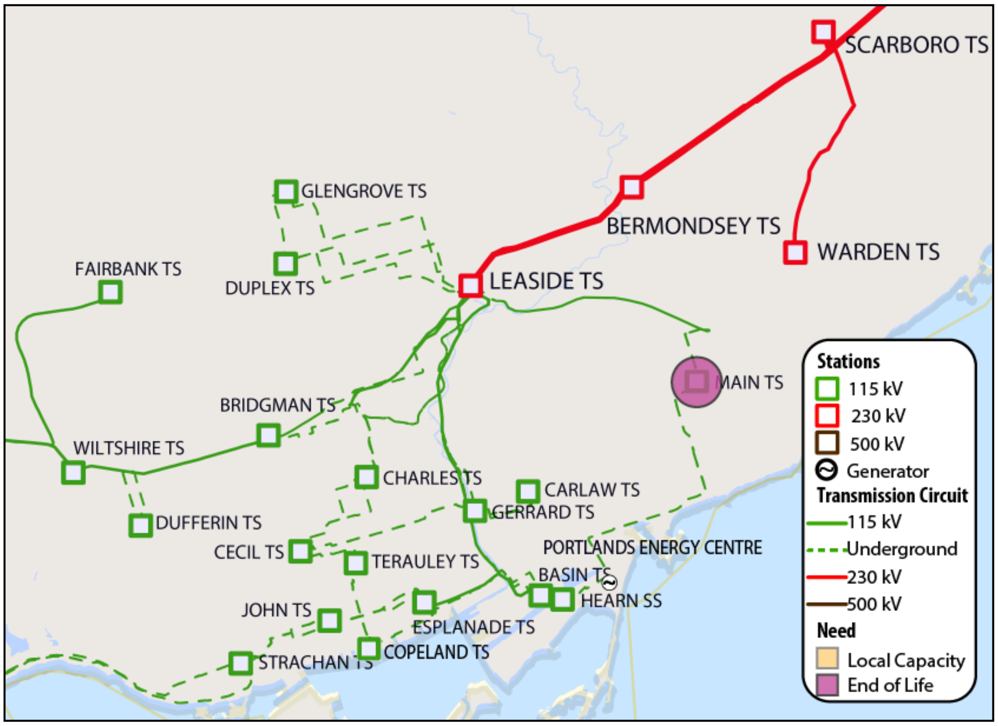
Main TS transformers and associated station equipment

Main TS is a local transformer station serving approximately 60 MW of load in east-central Toronto, including the Danforth and Beach neighbourhoods (Figure 6-3). The two transformers at the station, T3 and T4, are currently about 50 years old. Hydro One is currently working with Toronto Hydro to replace the end of life transformers, along with other equipment, such as 115 kV line disconnect switches, current transformers and voltage transformers.

Main TS is supplied by a combination of overhead and underground 115 kV circuits from Leaside TS to Hearn TS (H7L and H11L). Two sections of the original underground cable supply circuits are currently undergoing refurbishment due to their age (about 60 years old) and condition.

The station is currently more than 70 per cent utilized and resupplying the area load via adjacent station facilities is not possible. As with many established areas of the city, urban growth and development is likely in the Main TS area.

Figure 6-3: Location of Main TS



6.2.1.2 Medium-term Asset End-of-life Replacement Needs

Four asset end of life replacement needs occurring in the medium term were considered within the scope of this plan (Table 6-2). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

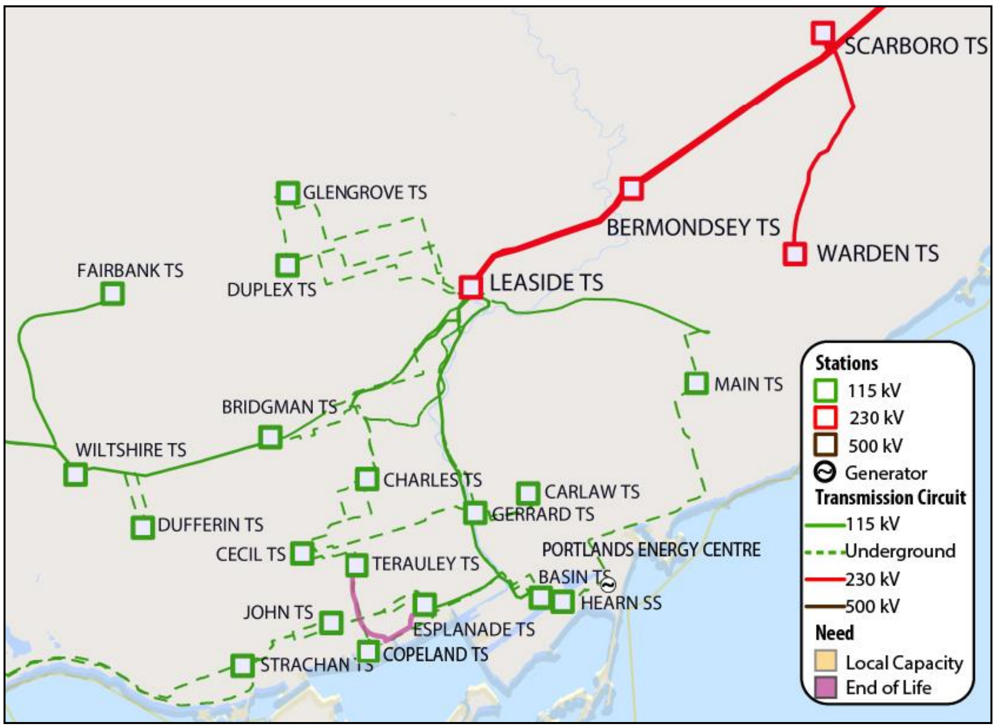
Table 6-2: Toronto Region End-of-life Asset Replacement Needs (Medium term)

Facilities	Need	Expected Timing
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9, and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers T1, T2, T3, T4, T6, and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026

C5E/C7E 115 kV underground transmission cables

The 115 kV underground transmission cables C5E and C7E provide supply to Terauley TS in Toronto's downtown core. Installed more than 58 years ago, these paper-insulated, low-pressure oil filled cables extend about 3.6 km from Esplanade TS to Terauley TS, and are partially routed near Lake Ontario (Figure 6-4). They have been deemed by Hydro One to be at the end of their useful life, and requiring replacement as soon as possible, given that the risk of cable failure resulting in oil leaks and adverse environmental impacts is increasing with time.

Figure 6-4: C5E/C7E 115 kV Underground Transmission Cables

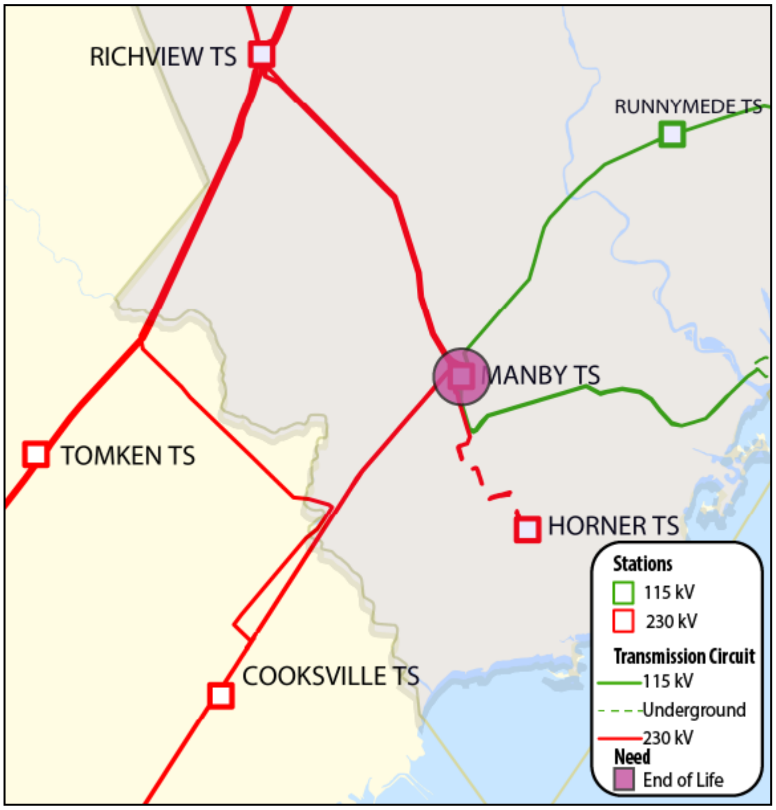


Manby TS

Manby TS is a major switching and autotransformer station supplying the western portion of the central Toronto 115 kV transmission system (Figure 6-5). Station facilities include six 230 kV/ 115 kV autotransformers (T1, T2, T7, T8, T9 and T12), a 230 kV switchyard, a 115 kV switchyard, and three DESNs with six 230/27.6 kV step-down transformers that supply customers in the immediate vicinity of the station. Three of the autotransformers (T7, T9 and T12) and one of the step-down transformers (T13) are close to 50 years old and, along with the 230 kV oil circuit breakers, have been identified to be at the end of their useful life. All of this end of life equipment is scheduled to be replaced in 2025-2026.

Addressing end of life needs at Manby TS represents a major undertaking that needs to be well coordinated in consideration of Toronto's long term needs and future supply options.

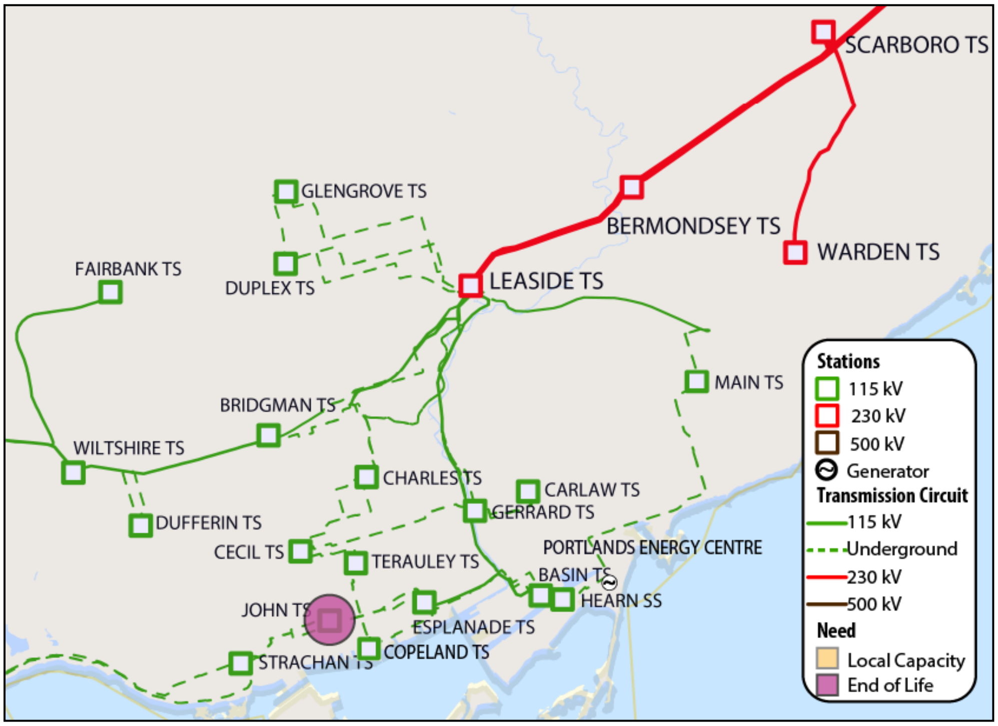
Figure 6-5: Location of Manby TS



John TS

Built in the 1950s, John TS is connected to the 115 kV Manby West system and supplies much of Toronto's downtown financial district (Figure 6-6). Station facilities include six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5 and T6) and a 115 kV switchyard. Toronto Hydro's switchgear at the station has reached the end of its useful life, and is expected to be replaced starting in 2024-2025. In addition, Hydro One has identified the step-down transformers at John TS (T1, T2, T3, T6), as well as the 115 kV breakers to be at the end of their useful life and require replacement within the near to medium term. Because of their deteriorated condition, transformer T4 has already been replaced and T1 is scheduled to be replaced in Q4 2019. The approximate timing for the station refurbishment is 2026-2027.

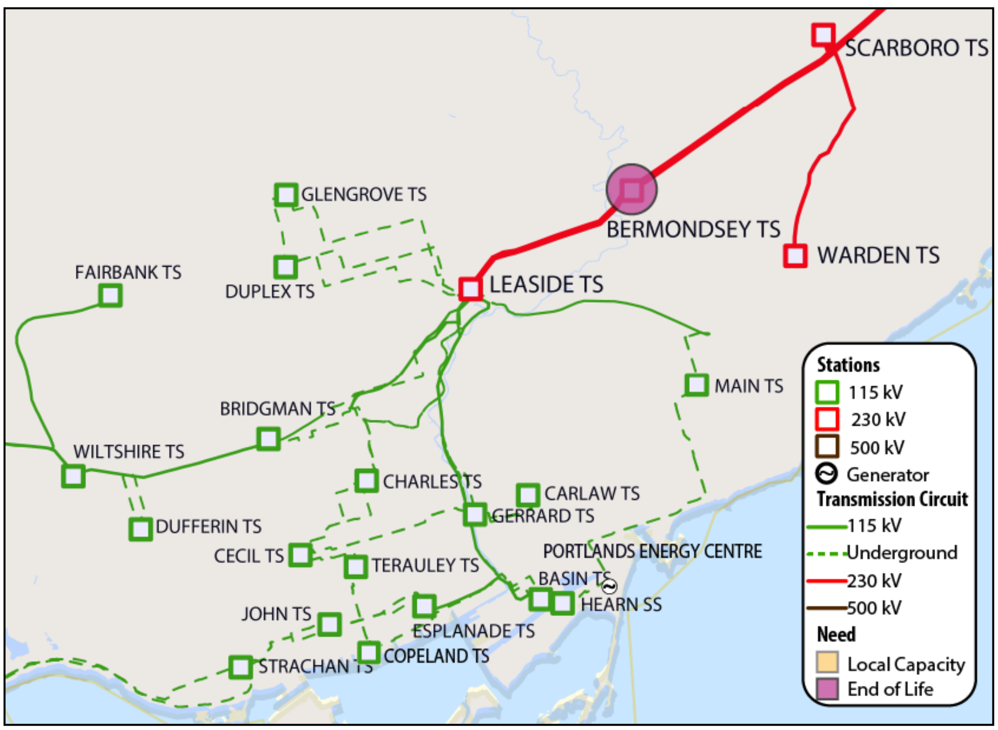
Figure 6-6: Location of John TS



Bermondsey TS

Bermondsey TS supplies customers in the western part of Scarborough (Figure 6-7). The station is comprised of two DESNs, one of which (T3/T4 DESN 2) was built in 1965, and the other (T1/T2 DESN 1) in 1990. DESN 2 has been identified by Hydro One to be at its end of life and is expected to be replaced by 2025-2026. Bermondsey TS has a total of 18 distribution feeders supplying Toronto Hydro customers: the older T3/T4 DESN 2 has 12 feeders, while the newer T1/T2 DESN 1 has six feeders. The total loading on the station is forecast to remain below its capacity over the planning horizon. This provides an opportunity to review configuration and component sizes to best meet future needs.

Figure 6-7: Location of Bermondsey TS



6.2.2 Supply Capacity Needs

Supply capacity needs at local step-down transformer stations were found at five transformer stations. A breakdown by year of the forecasted station loadings, as well as a more detailed description of the methodology for carrying out this assessment, is provided in Appendix E: Station Capacity Assessment.

6.2.2.1 Local Transformer Station Capacity Needs

Table 6-3: Toronto Region Transformer Station Capacity Needs

Station	Description	Timing[12,13]
Manby TS	A transformer capacity need was identified for the load supplied by all three DESNs[14]	2023 for T5/T6 2032 for T3/T4 2034 for T13/T14
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030 for T13/T15 2033 for T12/T14
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035

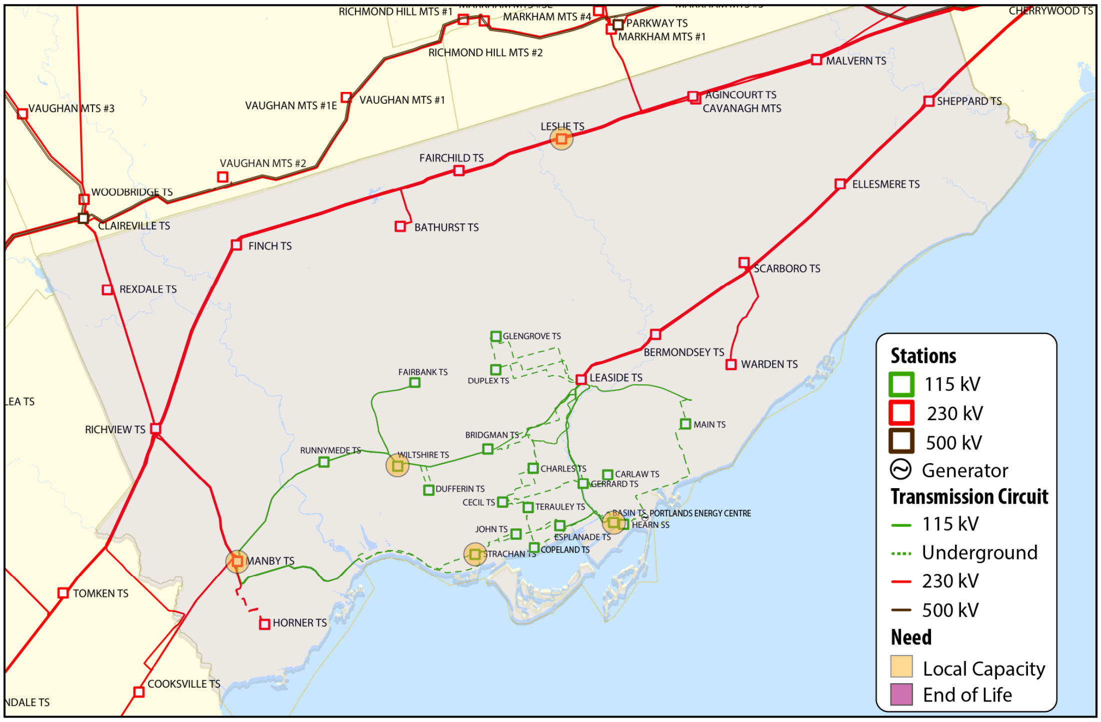
The locations of the local capacity needs are shown in Figure 6-8; four of the five local capacity needs are situated in the Central Toronto area.

[12] The timing presented in the table is consistent with the demand outlook provided by Toronto Hydro (net of new energy efficiency and distributed energy resources until the end of 2020); the timing of these capacity needs inclusive of future energy efficiency codes and standards is discussed in the subsections following the table.

[13] Even though local transformer station capacity needs are presented in terms of the individual DESNs within the station, for the purpose of planning and implementing solutions, the needs at each station are generally addressed as one need requiring a holistic solution.

[14] This need was identified and a solution was recommended in the 2015 Central Toronto IRRP. The status of the 2015 recommendation is discussed in Section 7.2.

Figure 6-8: Location of Local (Transformer Station) Capacity Needs



Manby TS (step-down transformation capacity)

Manby TS currently consists of three DESNs connected to the 230 kV system. This step-down transformer station, which supplies customers in the area surrounding Islington Town Centre from the Humber River west to the Toronto City limit, shares a yard with, but is separate from, the larger Manby 230/115 kV autotransformer station that provides 115 kV supply to the western portion of downtown Toronto. With a combined capacity of 240 MVA (216 MW), all three DESNs are forecast to exceed their capacity, starting in 2023 for the T5/T6 DESN 2, 2032 for the T3/T4 DESN 1, and 2034 for T13/T14 DESN 3.

The peak demand impacts of efficiency codes and standards were not taken into account for the timing of this need. Demand at Manby TS has already exceeded the station's capacity in several recent years. This issue was discussed in the 2015 Central Toronto IRRP, solutions were evaluated, and the recommendations to address the need are currently being implemented by Hydro One and Toronto Hydro. These include building a second DESN at Horner TS in south Etobicoke, and transferring load from Manby TS to the new Horner DESN.

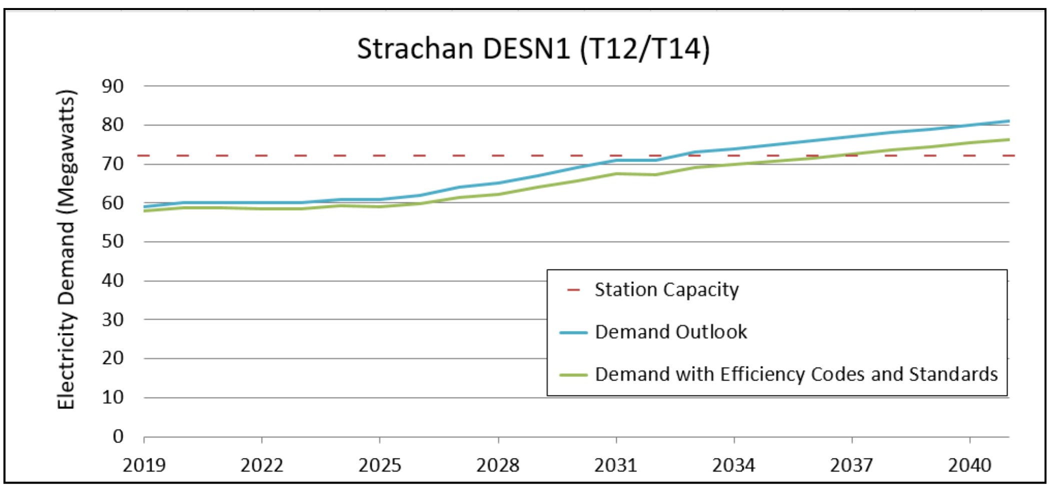
Strachan TS

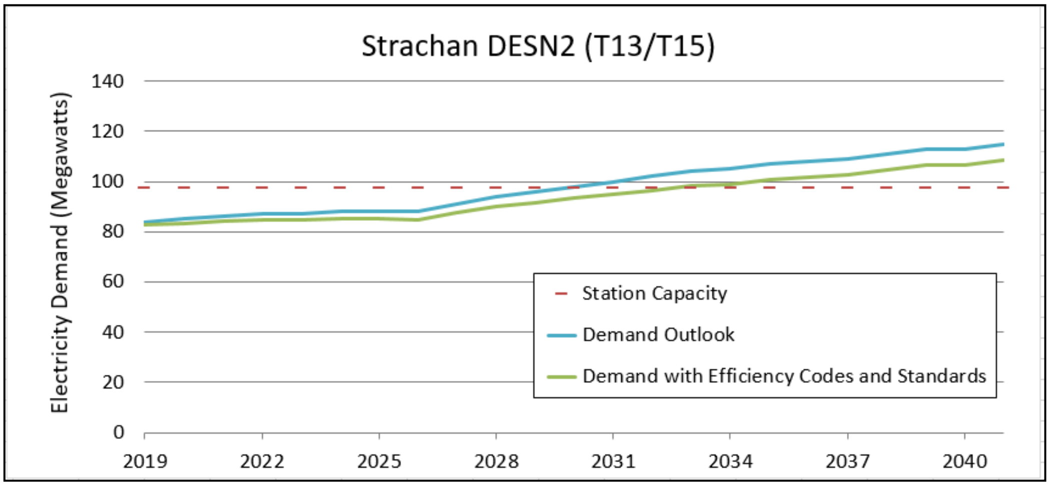
Strachan TS consists of two DESNs connected to the 115 kV system supplied from Manby TS (West Yard). Strachan TS supplies load to the west of the downtown core at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 188 MVA, or 169 MW (80 MVA for T12/T14 DESN 1, and 108 MVA for T13/T15 DESN 2).

The T13/T15 DESN 2 is forecast to reach its capacity as early as 2030, while the T12/T14 DESN 1 is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards, the timing of this need is deferred to 2033 and 2038 for the T13/T15 DESN 1 and T12/T14 DESN 2, respectively.

Figure 6-9 shows the demand outlook for the two DESNs at Strachan TS, as compared to the individual capacity of each DESN.

Figure 6-9: Demand Outlook for Strachan TS DESNs Compared to Capacity





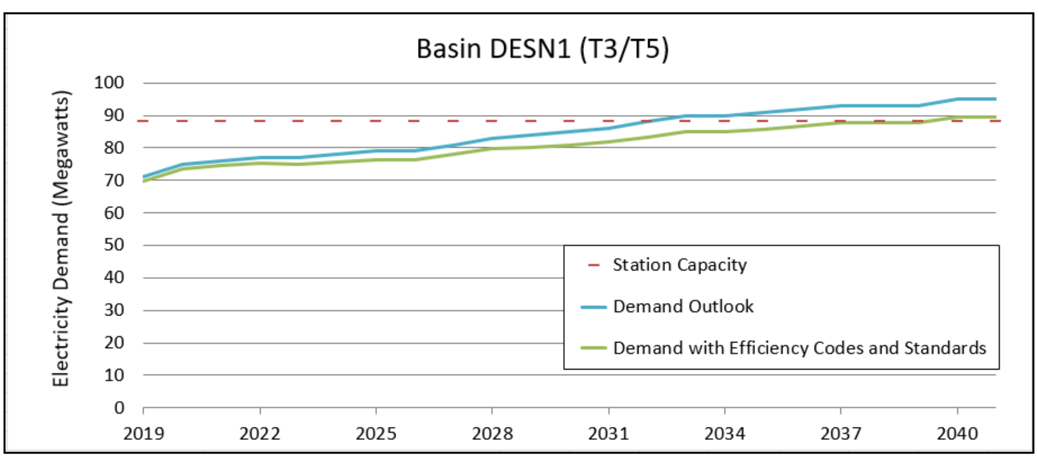
Basin TS

Basin TS has a single DESN (T1/T2) connected to the 115 kV system, supplying two low-voltage switchgear at a distribution voltage of 13.8 kV. The station has a total capacity of 98 MVA, or approximately 88 MW.

Basin TS is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards (post-2020), the timing of this need is deferred to 2040.

Figure 6-10 shows the demand outlook for Basin TS, as compared to the station capacity.

Figure 6-10: Demand Outlook for Basin TS DESN Compared to Capacity



In addition to the forecast growth, the City of Toronto and Waterfront Toronto have been engaged in a master planning exercise for the Port Lands neighbourhood redevelopment and re-naturalization of the mouth of the Don River. These plans involve a number of requests to examine relocation or redesign parts of the 115 kV transmission network in and around Basin TS, including the possible relocation of Basin TS itself.

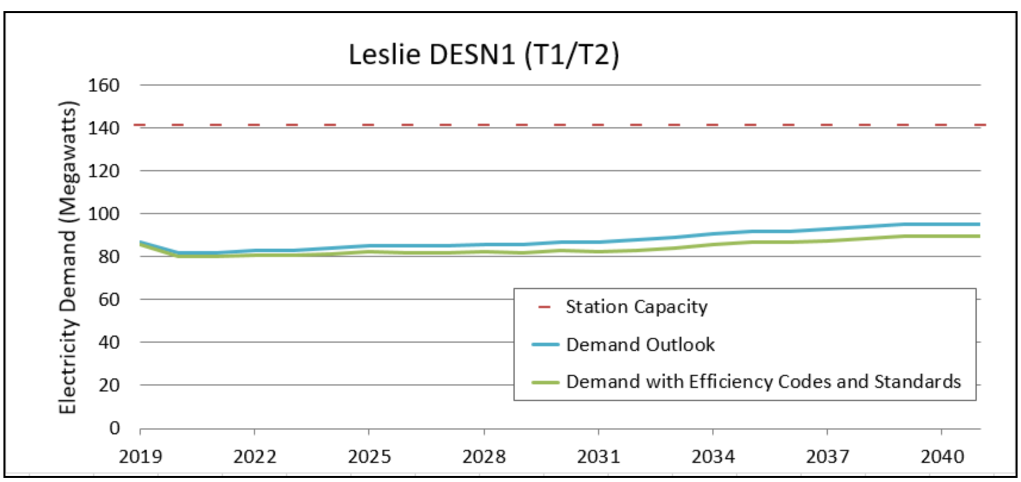
Given the absence of concrete plans and timelines for urban development in the area, the timing of the capacity need at Basin TS is uncertain.

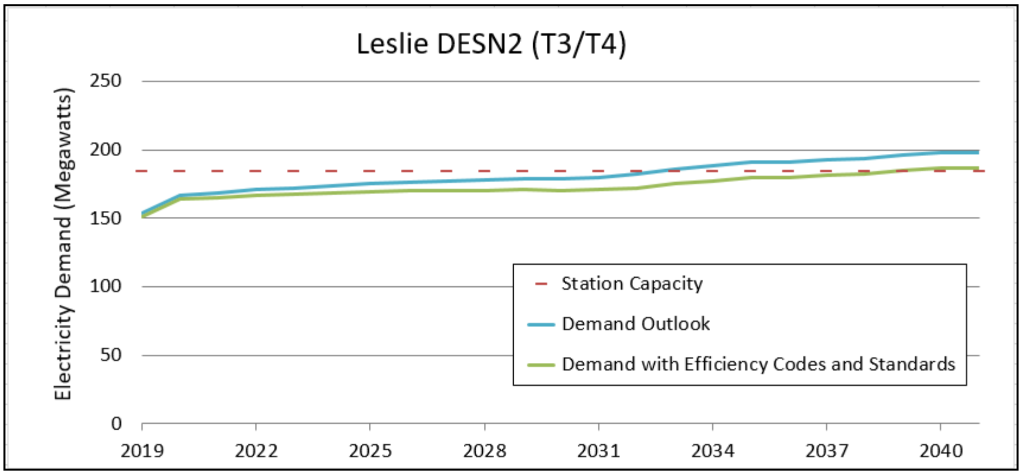
Leslie TS

Leslie TS has two DESNs connected to the 230 kV system. The T1/T2 DESN 1 supplies load at 27.6 kV and 13.8 kV, while the T3/4 DESN 2 supplies load at 27.6 kV. The total station capacity of Leslie TS is 325 MW. The T1/T2 DESN 1 has a capacity of 149 MVA (134 MW) and the T3/T4 DESN 2 has a capacity of 194 MVA (175 MW). While the other three transformers are relatively new (installed between 1988 and 2012), transformer T1, which was installed in 1963, may require replacement within the planning horizon of this IRRP, even though it has yet to be identified as being at the end of its life.

The T3/T4 DESN 2 is forecast to reach its capacity as early as 2033. Assuming the potential impact of future efficiency codes and standards, the timing of this need is deferred to 2039. Figure 6-11 shows the demand outlook for the two DESNs at Leslie TS, as compared to the individual capacity of each DESN.

Figure 6-11: Demand Outlook for Leslie TS Compared to Capacity





Wiltshire TS

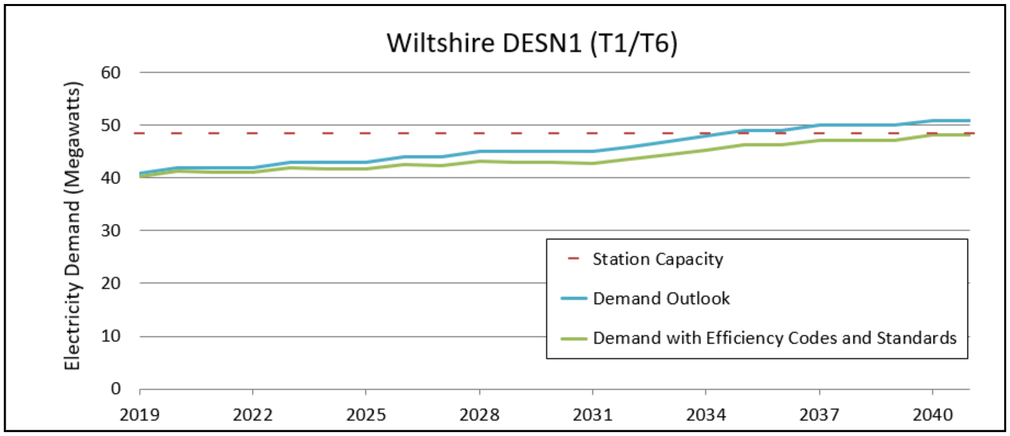
Wiltshire TS has two DESNs connected to the 115 kV system supplied from the Manby TS (East Yard). Wiltshire TS supplies customer demand to the northwest of the downtown core, including the Junction neighbourhood, at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 151 MVA, or 136 MW: 51 MVA for the T1/T6 DESN 1, and 100 MVA for the T2/T7 DESN 2. These two DESNs supply three Toronto Hydro 13.8 kV buses.

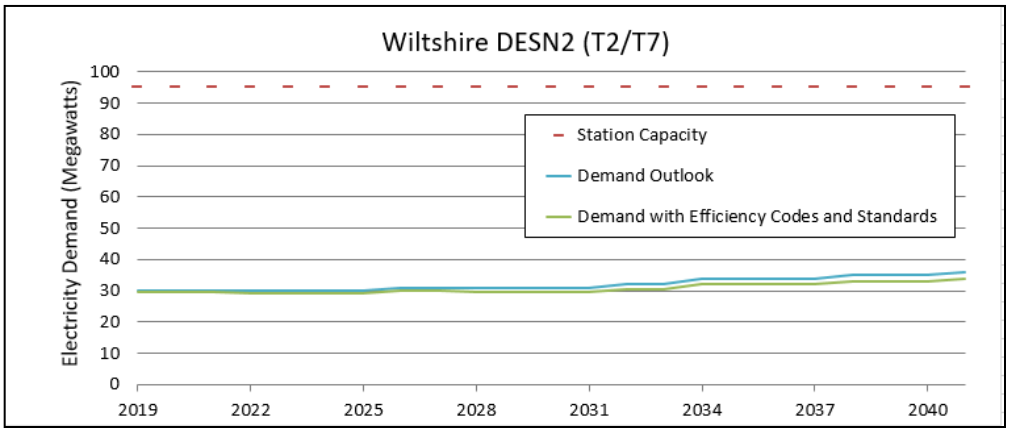
The outlook is forecasting load growth at Wiltshire TS, which can be attributed to growth and urban redevelopment in the area.

The T1/T6 DESN 1 is forecast to reach its capacity as early as 2035. Assuming the future potential impact of efficiency codes and standards, the timing of this need is beyond the study period.

Figure 6-12 shows the demand outlook for the two DESNs at Wiltshire TS, as compared to the capacity of each DESN.

Figure 6-12: Demand Outlook for Wiltshire TS DESN Compared to Capacity





6.2.2.2 Regional Supply Capacity Needs

Regional capacity needs are related to the 230 kV or 115 kV transmission system that delivers electricity from the interconnected grid into Toronto. The planning studies re-tested the need for the Richview TS to Manby TS 230 kV corridor upgrades that were recommended in the previous planning cycle. The results of this assessment reaffirm this need and are reported in this section. In the longer term, regional supply capacity needs emerge at Leaside TS, Manby TS, and on some 115 kV circuits within the Manby and Leaside Sectors.

Richview TS to Manby TS 230 kV corridor

The previous cycle of regional planning recommended that the 230 kV bulk supply to Manby TS from Richview TS be reinforced to accommodate demand growth in Toronto, primarily driven in the near term by mass transit projects. The planning studies undertaken for this IRRP re-tested the need for this additional LMC upstream of Manby TS, accounting for changes in assumptions related to the revised demand outlook provided by Toronto Hydro for the purpose of undertaking this IRRP, and the peak demand outlook for Cooksville west stations from the 2015 GTA West Needs Assessment.

The assessment confirmed that, under normal system configuration, the most limiting contingency is the loss, in 2021, of circuit R15K, which would cause R2K (also running from Richview TS to Manby TS) to exceed its capacity rating. This limitation exists regardless of whether the Metrolinx traction power substation (TPSS) is in-service; however, the additional capacity will support further mass transit electrification.

Without reinforcement to the Richview TS to Manby TS 230 kV circuits, the ability to transfer Dufferin TS to Manby East supply can become limited during summer peak conditions, following the same R15K single contingency. As discussed below (under Leaside TS and Manby TS autotransformers), transferring Dufferin TS to Manby TS supply is a possible control action in a PEC out-of-service scenario (as well as other issues that could impact supply in the Leaside TS sector). Since having this control action available helps ensure a reliable and resilient transmission supply to Toronto, the Working Group continues to recommend reinforcement of the Richview TS to Manby TS 230 kV circuits with a target in-service date as soon as possible.

The detailed assessment of the Richview TS to Manby TS corridor need is provided in Appendix F: Richview TS to Manby TS Corridor Study.

Supply to downtown Toronto from Manby West (Manby to Riverside Junction)

The Manby West supply sector comprises four 115 kV supply circuits (H2JK, K6J, K13J, and K14J), which run from Manby TS to Riverside Junction on overhead lines, with two (and in some spans, up to four) circuits on a common structure. From Riverside Junction, these circuits run underground to supply the downtown core.[15] The Manby West supply sector is considered "non-bulk" and is designed to continuously supply demand up to the loss of a single circuit.

The planning studies are showing that all four Manby TS to Riverside Junction circuits violate the reliability criteria between 2030 and 2040. Under the most severe single element loss, the remaining circuits can be as much as 120 per cent overloaded by 2040. This is a reliability concern that will need to be addressed in the long term.

Leaside TS and Manby TS autotransformers

The assessment of the Leaside autotransformer capacity is related to the presence and capacity of the 550 MW PEC facility, as both PEC and Leaside TS supply the Leaside sector. With an outage to the PEC steam turbine generator, the output of the plant would be reduced to 160 MW. Under this scenario, the Leaside autotransformers will begin to exceed their capacity limits by the 2030 to 2040 time frame, following outages on the 230 kV transmission lines that supply Leaside TS from Cherrywood TS upstream. With a full PEC outage, two of the six autotransformers at Leaside TS (T15 and T16) would be overloaded under peak demand conditions.[16]

During short-term outages of elements of PEC, system control actions to reduce the Leaside sector load through the transfer of Dufferin TS to the Manby sector will alleviate pressure on the Leaside autotransformers. While this is an acceptable short-term measure, it is not considered a permanent solution because it exposes the Manby sector, and Dufferin TS customers in particular, to supply security risks related to transmission outages in the Manby sector.

Manby TS autotransformer capacity needs were identified as emerging by the 2030 to 2040 time frame. This capacity constraint is related to the rating of the smallest autotransformer at Manby TS (T12) following the loss of a companion transformer. There may be value in factoring these findings into the end of life replacement of the Manby TS autotransformers in 2025-2026, if there is a cost-effective and technically feasible means of addressing this capacity constraint within the scope of the replacement.

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[15] The underground section from Riverside Junction to Strachan Avenue have been recently refurbished due to its age and condition.

[16] The 2030 forecast year was used to assess the full PEC outage scenario; it is likely that if such a scenario were experienced today at the time of system peak, then the Leaside TS autotransformers could experience an overload.

Bayview Junction to Balfour circuit (L15W) thermal capacity

The planning assessment shows that following the loss of circuit L14W, the companion circuit L15 (from Bayview Junction to Balfour Junction in the Leaside sector[17]) is forecast to marginally exceed its Long term emergency rating (LTE) in 2040. This need is deferred beyond the planning horizon once the forecast efficiency codes and standards savings are taken into account.

6.2.3 Load Security Needs

The transmission system must exhibit acceptable performance while following specified design criteria contingencies. The load security criteria can be found in Section 7.1 of ORTAC, and a summary of the load security criteria can be found in Table 6-4. All transformer stations in the Toronto region have at least a dual transmission supply, which allows the load served at the station to remain uninterrupted in the event of a single element contingency. Supply interruptions may occur after multiple element contingencies, but under all possible interruption scenarios, the amount of load interrupted remains within the limits prescribed in ORTAC.

Table 6-4: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

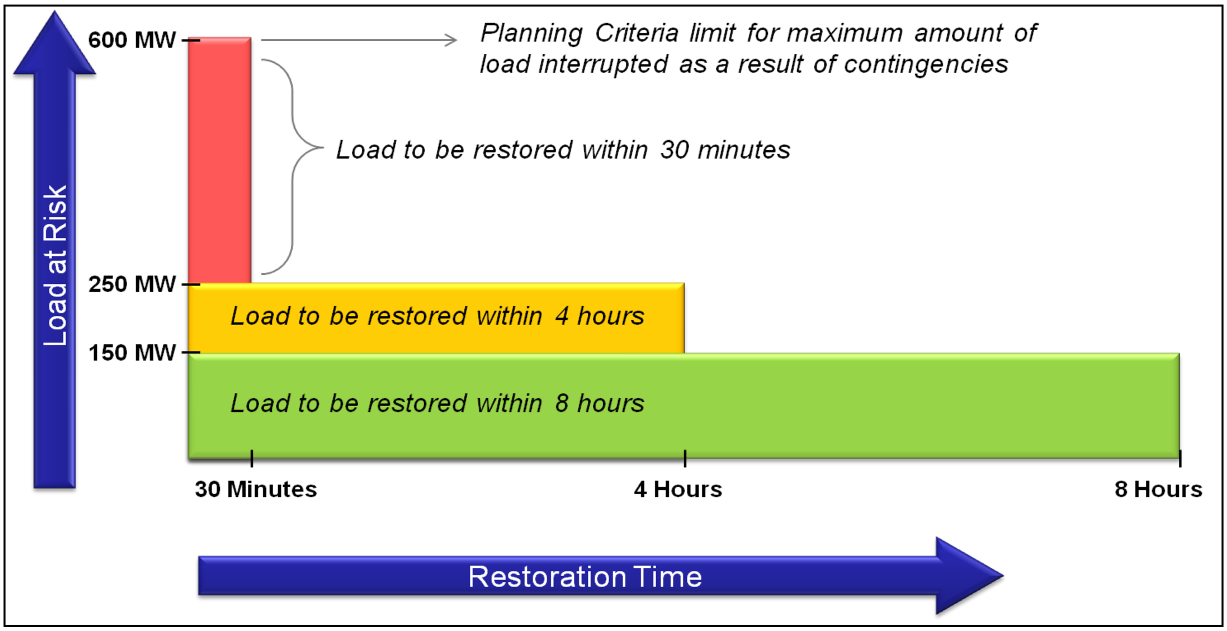
6.2.4 Load Restoration Needs

Described in Section 7.2 of ORTAC, load restoration criteria specify that the transmission system must be planned such that following design criteria contingencies, all interrupted load must be restored within approximately eight hours. When the load interrupted is greater than

[17] These circuits are part of the path supplying Wiltshire TS from Leaside TS.

150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours. When the load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes. A visual representation of the load restoration criteria is shown in Figure 6-13.

Figure 6-13: Load Restoration Criteria



No load restoration needs were identified in the Toronto region following the design criteria contingencies that were tested. Under a situation where load loss has occurred and the transmission system has been reconfigured to restore power, but some customers are still experiencing an outage, additional measures may be taken in the operational time frame. These measures may include dispatching crews to repair the transmission system, reconfiguring the transmission or distribution system to transfer load to another delivery point, and use of temporary facilities, etc. Although electricity interruptions can not be eliminated, where possible, the system operator, transmitter, and distributor will undertake measures in real time to respond to outages and restore load as quickly as possible.

6.2.5 Discretionary Reliability Needs

Reliability performance is, in part, a function of the criteria that the transmission system needs to meet. In other words, the planning criteria stipulate the functional requirements of the transmission system to ensure reliability performance. Within Toronto, specific criteria apply to different parts of the transmission system because of the function and resulting consequences of the loss of those different parts. In other words, less stringent criteria generally apply to transmission facilities where the impact is only local. Conversely, more stringent criteria apply when the consequences of a loss have a wider impact on the interconnected grid. The stringency of the planning criteria is commensurate with the severity of the consequence of contingencies that can impact the interconnected grid.

While, for study purposes, this plan applied the more stringent criteria to all parts of Toronto's transmission system (e.g., by assessing 'local area' facilities against 'bulk power system' criteria), not all areas are required to meet the more stringent criteria. ORTAC (Section 7.4) permits higher levels of reliability to be adopted for specified reasons. The results of the assessment in this study highlighted some 'discretionary reliability needs' for the purpose of generating insights as to where there may be opportunities to improve performance, but for which actions to resolve them are not required by the performance criteria that govern the planning and design of the electric power system. The discretionary reliability needs are documented in Appendix D: Toronto IRRP Study Results.

6.2.6 System Resilience for Extreme Events

One of the key measures of a resilient transmission system is its ability to withstand interruption, or restore supply during or after extreme events that impact many parts of the system. This section summarizes the capability, following analysis, of Toronto's regional transmission system to maintain supply and manage the risk posed by low-probability, high-impact events.

In 2013, the IESO conducted an assessment of the amount of load that could be restored following specific extreme contingencies involving the system that supplies downtown Toronto. The results of this assessment have not been made public due to security concerns related to the disclosure of critical energy infrastructure information and possible system vulnerabilities.

For this IRRP, key scenarios from the 2013 study were re-examined for the years 2020 and 2025. These include the loss of:

- Manby TS 115 kV switchyard
- Leaside TS 115 kV switchyard
- Four circuit tower structures emanating from the Manby TS and Leaside TS 115 kV switchyards

The results of the updated analysis found that the impact of the extreme contingencies on the 115 kV transmission system was limited to load interruptions within the Toronto region.

6.3 Summary of Needs Identified

Table 6-5 summarizes the electric power system needs identified in this IRRP. Note that discretionary needs identified in Section 6.2.5 are not included because these issues are flagged as potential opportunities to enhance reliability to Toronto but they do not require actions to address them at the present time.

Table 6-5: Summary of Needs Identified

Facilities	Need	Expected Timing
End-of-Life Assets		
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2 km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6 km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9 and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026
Local Transformer Station Capacity		
Manby TS (DESN)	A transformer capacity need was identified for the load supplied by all three DESNs	2023
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030

Facilities	Need	Expected Timing
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035
Regional Capacity		
Richview TS to Manby TS 230 kV Corridor	Load meeting capability upstream of Manby TS	2021
Supply to downtown Toronto from Manby West (Manby to Riverside Junction)	Load meeting capability of the 115 kV lines supplying downtown Toronto	2030-2040
Leaside TS and Manby TS	A capacity need was identified for Leaside TS and Manby TS 230/115 kV autotransformers	2030-2040
Bayview Junction to Balfour Junction Circuits	Overloading of L15 circuit for the loss of its companion circuit, L14W	2040

7. Plan Options and Recommendations

This section outlines the options considered to address transmission needs in the Toronto region, as well as the recommended plan with respect to each of these needs.

In considering options and developing recommendations, the Working Group has been mindful of the interest and preference, communicated through engagement with stakeholders, such as the City of Toronto, a local advisory committee that was in place from 2016 to 2018, and the general public, to explore NWAs, such as DERs, for dealing with electricity system needs.

Given the interest in NWAs as possible solutions for addressing Toronto's regional transmission needs, additional context on the changing landscape with respect to these resources, and on the approach to considering them, is provided below.

DERs as options to address needs in Toronto

The uptake in DERs across the province over the last decade is having an impact on the electricity system, both in terms of system demand and operability. While centralized procurement programs that supported the development of most DERs[18] are no longer in place, DER deployment is expected to continue in Toronto. Toronto Hydro has filed investment plans for approval with the OEB to increase its ability to connect DERs to its system, and the IESO has expressed support for these plans.[19]

Much of the IESO's recent work with respect to DERs has focused on identifying the barriers to their development as alternatives to wires-based solutions, and options for reducing or overcoming those barriers. Specifically, the barriers to implementation of cost-effective NWAs, including DERs, in regional planning are being investigated as part of the IESO's regional planning review initiative.[20] Further, a number of DER-focused initiatives are being undertaken as part of the work plan associated with the IESO's *Innovation Roadmap*.[21] These initiatives

[18] Since 2006, nearly 2,000 distributed energy resources (DERs), including solar PV, CHP, energy storage and wind, have connected to Toronto's distribution system.
[19] See Toronto Hydro's rate application EB-2018-0165, Exhibit 2B, Section E7.2; and Exhibit 2B, Section B, Appendix F for IESO's Comment Letter.
[20] Launched in 2018, the regional planning review process is exploring a number of enhancements to regional planning, including potential barriers to non-wires solutions, opportunities for coordination between bulk system planning, community energy planning and market renewal, and a long term approach to replacing end-of-life transmission assets.
[21] http://www.ieso.ca/en/Get-Involved/Innovation/Innovation-Roadmap

include research and white papers, demonstration and evaluation projects, and capital projects and process improvements. For a full list and descriptions, visit the innovation projects page on ieso.ca.

The Working Group believes that DERs need to continue to be studied to build the necessary tools and experience required to consider and evaluate them as potential solutions to regional electricity needs. This work is being undertaken through the above mentioned work plan. In the meantime, continued dialogue with the community is expected to play an important role in defining the potential for cost-effective NWA solutions. Further details are provided in the plan recommendations.

7.1 Evaluating Plan Options for Addressing Needs Identified in Toronto

The following sections describe the options considered to address the needs identified in Section 6.2.

The evaluation of possible plan options takes into consideration a number of factors, including technical feasibility, timing, cost, and alignment with local priorities. In light of the importance of cost as a planning consideration, solutions that are cost-effective and that maximize the use of existing infrastructure and assets are typically given priority for inclusion in the evaluation.

To help ensure that solutions will be available in time to address pressing needs, the IRRP identifies specific actions to be undertaken and/or implemented in the near and medium term. Given forecast uncertainty and the potential for technological and policy changes, investment in longer-term needs is not prudent at this point in time. Instead, the long term plan focuses on developing and maintaining the viability of long term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, solutions are needed to address (1) end of life asset replacements; (2) local transformer station capacity, and (3) regional supply capacity needs. In addition, the plan identifies some discretionary needs related to maintaining a higher level of reliability performance than those prescribed in ORTAC. This recognizes Toronto's position as the largest urban centre in Canada, and the ORTAC provision allowing the transmission customer and transmitter to agree on higher (or lower) levels of reliability. Firm recommendations to address discretionary needs are dependent on the availability of cost-effective solutions and the risk of the need materializing.

In developing the plan, the Working Group examined a range of solutions to address the near term needs, as well as activities to begin to lay a foundation for addressing needs in the longer term. These options are discussed and evaluated in the following sections.

7.1.1 Options for Addressing End of Life Asset Replacement

When transmission equipment reaches end of life, a number of alternatives can be considered. Transmission or distribution facilities may have changed since the equipment was built, community needs may have evolved, equipment standards may have changed, and/or opportunities for other options, such as energy efficiency, may be able to play a role.

Options to address end of life asset replacement needs in the Toronto region included:

- Retiring the asset or facilities
- Replacing the assets to the "right size" (e.g., larger or smaller) based on considerations, including future electricity demand, or changes to the use of the asset to realize reliability, resilience, or other benefits that an alternate configuration may provide
- Replacing the assets "like for like" or with the closest current equivalent
- Implementing NWAs

Based on the assessments conducted in this IRRP, each of the assets reaching its end of life in this plan was deemed critical for maintaining a sufficient and reliable supply of electricity to customers. As such, and given the magnitude and persistence of the needs, complete retirement and replacement with NWAs was screened out as an alternative in favour of replacing the assets with the closest available equivalent.

Leaside Junction to Bloor Street Junction 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)

Three options were assessed to inform the preferred approach for addressing this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines to increase future capacity (but continue to operate at 115 kV, for now):** This approach was ruled out because assessment indicated that none of these circuits would be thermally limited within the planning horizon. Also, because there is no plan to increase the transmission supply voltage (e.g., to 230 kV) to any of the stations supplied by the HxL or HxLC circuits, there would be no benefit for investing in replacement circuits at a higher operating voltage (or any associated tower investments) within the planning horizon.

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon. New 115 kV transmission lines along this path built to today's standards are expected to be able to carry more load, and operate in a more reliable manner, as compared to the existing equipment.

3. **Replace end of life assets with NWAs:** As NWAs, such as energy efficiency or DERs, would be very expensive compared to replacing end of life assets, the Working Group determined that they do not present a viable approach.

Table 7-1 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-1: Options for Addressing Leaside Junction to Bloor Street Junction 115 kV Lines

	Replace with 230 kV capable	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintains reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)

These two lines are critical for supplying Toronto's electricity needs. Three options were assessed to inform a recommendation on the preferred approach to address this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines (but continue to operate at 115 kV for now):** This approach was ruled out because assessment results indicated that none of these would be thermally limited within the planning horizon. Since there is not a plan to increase the transmission supply voltage to any of the stations supplied by these lines, it would not be beneficial to invest in replacement circuits at a higher operating voltage (or any associated tower investments).

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon.

3. **Replace end of life assets with NWAs:** Given that energy efficiency, DERs and other NWAs would be very expensive compared to replacing end of life assets, the Working Group determined that NWAs do not present a viable approach.

Table 7-2 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-2: Options for Addressing Leaside TS to Balfour Junction Transmission

	Replace with 230 kV	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintain reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Main TS

The IRRP looked at different approaches for addressing end of life assets at Main TS, which include the two step-down transformers and associated medium-voltage switchgear. Eliminating the station outright was not considered to be a feasible option, as it is over 70 per cent utilized and resupplying the customer demand in the area from adjacent station facilities is not possible with the existing infrastructure.

NWAs, including energy efficiency or DERs, are not suitable options for addressing asset condition-related needs. As an alternative to the step-down station, energy efficiency or DERs would be cost prohibitive as compared to replacing end of life assets.

Other options were considered and are discussed below:

1. **Converting Main TS to 230 kV operation:** Providing a 230 kV connection to Main TS could be achieved by rebuilding the existing 115 kV supply circuits from Leaside TS (H7L and H11L), or by building a new 230 kV line. New 230 kV transformers and associated high-voltage switchgear would be needed at the existing station, or at a new station location. The 115 kV rebuild option would make the existing H7L and H11L circuits unavailable to supply Hearn station from Leaside TS, while building a new 230 kV connection would be very expensive. In addition, as Main TS is space constrained, the larger 230 kV transformers may not be accommodated on the existing site. As property for building a new station in the vicinity is also limited, this alternative was deemed not viable.

2. **Supplying Toronto Hydro's switchgear from new transformers at Warden TS:** As this approach would require the building of several new distribution cable circuits from Warden TS, which is 4.5 km from Main TS, the Working Group determined that this alternative would be expensive, and impractical, considering the number and length of new distribution cables required.

3. **Replacing the transformers at the existing Main TS location with new 115 kV transformers:** This approach is technically feasible and can be accommodated at the existing station location. Given the potential for future high density urban development in the Main TS service area, Toronto Hydro has recommended, that the existing 45/75 MVA transformers at Main TS be replaced with 60/100 MVA transformers. Even with the cost differential between the two transformer sizes – which Hydro One has estimated to be about $300,000 – the cost of this approach is far less than either option 1 or 2. The Working Group supports this recommendation.

Options 1 and 2 above would have the benefit of shifting load from the 230 kV/ 115 kV autotransformers at Leaside TS to the 230 kV system, providing capacity relief for the Leaside TS autotransformers. Option 3 is the most cost-effective, even with the marginal additional cost of replacing the existing 45/75 MVA transformers with 60/100 MVA transformers.

Table 7-3 summarizes the options assessed to address the end of life asset needs at Main TS.

Table 7-3: Options for Addressing Main TS End-of-life Assets

	Convert to 230 kV	Supply Main TS area from Warden TS	Replace Transformers at Main TS
Summary of Option	• Replace existing transformers with 230 kV transformers; rebuild the circuits supplying Main TS to 230 kV	• Install new 230 kV transformers at Warden TS and supply Main TS service area with new distribution cables from Warden TS	• Replace existing transformers at Main TS with new transformers; take the opportunity to install higher capacity transformers to supply future development in the area
Potential Benefits	• This option would provide relief to the Leaside TS 230 kV /115 kV transformers as it would move Main TS to 230 kV supply	• This option would provide relief to the Leaside TS 230 kV/ 115 kV transformers as it would move Main TS to 230 kV supply	• This option maximizes use of the existing infrastructure supplying the area • Provides capacity for area growth and development
Potential Risks/ Issues	• The cost would be very high • Capacity relief at Leaside TS may only be needed at or beyond the planning horizon • Main TS is a small station; this option may not be feasible	• The technical feasibility of running very long distribution feeders from Warden to Main TS load is uncertain; there may be reliability impacts • The cost would be very high • Capacity relief at Leaside TS may only be needed beyond the planning horizon	• This option does not provide capacity relief for Leaside TS, which may only be needed beyond the planning horizon • Does not preclude upgrading to 230 kV at a later date

C5E/C7E 115 kV underground transmission cables

Given the complexity and lead time required to implement underground infrastructure through downtown Toronto, Hydro One launched an EA process for the cable replacement in May 2018. Community engagement related to the options is currently underway, with five underground routes under consideration. The route investigation will consider stakeholder input, and assess existing easements and rights-of-way, costs, and other technical and environmental considerations. OEB Leave to Construct approval will also be required.

Since the Working Group has determined that there are no suitable alternatives to replacement, this IRRP recommends that Hydro One continue with actions to replace the existing 115 kV cables.

Manby TS

Given the extent of end of life assets at Manby TS, development of a well-coordinated plan will need to consider the capacity of the station to meet future growth needs in Toronto, accommodate additional short-term transfers to the Manby sector in the event of emergencies (such as a loss of Leaside sector supply or PEC outages), and maintain reliability. For example, the plan required to address the assets reaching end of life in the 230 kV switchyard should be coordinated with the remedial action scheme (RAS) recommended in the 2015 Central Toronto IRRP, with the new terminations required to accommodate the new Richview to Manby TS circuits, and the long term need for additional capacity to supply growth in downtown Toronto. NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group will continue to assess transmission options and develop a recommendation concerning the significant end of life asset needs at Manby TS. It is recommended that this work commence in the RIP.

John TS

The end of life needs at John TS represent a major undertaking that needs to be coordinated with other plans to reinforce step-down supply capacity in the downtown core, including Toronto Hydro's Copeland TS (Phase 1 and Phase 2). For example, Copeland TS will provide an opportunity to review the configuration and major equipment capacity (i.e., right sizing) at John TS, to ensure it meets future needs. Furthermore, the 115 kV station design is in a "ring-bus" configuration and the end of life need provides an opportunity to review this configuration, while considering costs, operational flexibility, reliability to customers and transmission system development plans in the area.

Coordination of this work with Copeland TS is vital for providing the additional capacity to facilitate outage planning at John TS for the execution of a replacement plan, while maintaining reliable supply in Toronto's downtown district. Since this need is driven by the condition of the assets, NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group therefore recommends that the replacement plan for end of life equipment at John TS be further assessed through continued coordinated planning, commencing with the RIP.

Bermondsey TS

The station load is forecast to reach about 173 MW over the study period, after accounting for energy efficiency codes and standards. While there is a continuing requirement for the station to supply customers in the area, the total load on Bermondsey TS is forecasted to remain well below its current capacity over the planning horizon.

The options for addressing the asset end of life need at Bermondsey TS are summarized as follows:

1. **Retire (and decommission) the T3/T4 DESN at its end of life:** This option would mean supplying the entire load at Bermondsey TS from the T1/T2 DESN, and expanding the switchyard to accommodate new feeders (i.e., transferring the 12 feeders from the T3/T4 DESN to the T1/T2 DESN). However, this intra-station transfer would result in the remaining DESN nearing its capacity limit by the end of the study period.

2. **Replace the 84/140 MVA and 75/125 MVA end of life transformers with smaller 50/83 MVA transformers:** According to Hydro One, the cost of feeder work would be significantly more than the $600,000 savings for smaller size transformers ($300,000 per transformer).

3. **Replace like for like:** Based on the information available, this option will minimize the cost of end of life work at the station, while retaining some ability to grow and accommodate transfers within the station.

Based on the options put forth, NWAs were screened out at a feasible option to address this end of life need. Further assessment is needed to determine the cost and feasibility of option 2, above. The Working Group therefore recommends that a plan be developed within the scope of the RIP.

7.2 Options for Addressing Supply Capacity Needs

Based on the demand outlook, capacity needs in the Toronto region are centered on a number of transformer stations (DESNs) supplying local neighbourhoods in the city.

Local transformer station capacity needs at Manby TS, Strachan TS, Leslie TS and Wiltshire TS

For the need at Manby TS, the 2015 Central Toronto IRRP recommended that a second DESN be built at the adjacent Horner TS. Part of the rationale for the Horner TS expansion was to provide relief for Manby TS through permanent load transfers. The second DESN is expected to be in-service by late 2021.

The station capacity needs at Strachan TS, Leslie TS and Wiltshire TS are far enough into the future that there is sufficient time to monitor demand changes and revisit these needs in the next planning cycle. Further, based on a preliminary review of possible approaches, capacity is available either at other DESNs within the station, or at adjacent stations to permit planning for load transfers to provide relief to the DESNs that are forecast to reach their capacity. These transfers will require planning and investment to implement.[22]

To address the capacity need at Strachan TS, the capacity that is expected to be made available by Copeland TS (Phase 1 and Phase 2) is likely to allow for a permanent load transfer. While the feasibility of implementing such a transfer is not yet clear, there is sufficient time to monitor growth and assess the feasibility of various options. If demand grows faster than anticipated, or the forecast for energy efficiency changes, additional measures to address future capacity needs at Strachan TS – such as energy efficiency or other NWAs – can be explored and implemented, provided they are feasible and cost-effective.

[22] These types of actions are normally undertaken by the distributor as part of distribution system planning.

For the needs at Leslie TS and Wiltshire TS, capacity at other DESNs within the station is sufficient to accommodate additional load. This work will be undertaken by Toronto Hydro and Hydro One, with enough lead time to plan and implement intra-station transfers, if and when they are needed.

Local station capacity need at Basin TS

The capacity need at Basin TS arises as early as 2033; however, after considering the impact of efficiency codes and standards, the timing could be deferred to 2040. That said, a number of complicating factors related to the uncertainty of future demand growth at Basin TS must be taken into account. These relate to:

- Planned urban developments at the site and neighbourhood level
- City-led district energy plans
- The potential for economic growth, specifically related to intensification of commercial activity, for example, at the former Unilever site and the film studio district
- The relocation – proposed by the City of Toronto and Waterfront Toronto – of a significant number of existing high-voltage transmission facilities in the area

These uncertainties will impact the scope and timing of the needs, as well as the configuration of the electricity infrastructure in the area, including the ultimate size and location of Basin TS.

Cost-effective NWAs, including DERs and energy efficiency, should be explored to defer the needs at Basin TS, once they are further defined. Ongoing dialogue with stakeholders will be required to help identify feasible and cost-effective solutions, as well as prospective developments that could address the specific characteristics and timing of needs in the area. Since this is driven primarily by the need to supply local customers within Toronto Hydro's service territory, the Working Group agrees that the assessment of NWAs as potential solutions should be coordinated by Toronto Hydro.

7.3 Options for Addressing Regional Supply Capacity Needs

Options to address the regional supply capacity needs identified in Toronto are described below.

Richview TS to Manby TS 230 kV corridor

Options to address this need were assessed in the 2015 Central Toronto IRRP, the 2017 IRRP Addendum and the 2016 RIP by Hydro One. Since then, there have been no material changes to either the scope of the options or the preferred approach, which is planned to occur in the following two phases:

- **Phase One:** Rebuild the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This will allow for the two additional circuits to supply Manby TS, but avoid the need to build new terminations, including new breakers at Manby.
- **Phase Two:** To be coordinated with the Manby TS end of life refurbishment, new circuits will be separately terminated on the Manby 230 kV bus, and at Richview TS they will connect to existing 230 kV circuits between Claireville TS and Richview TS, thereby unbundling the two supercircuits. The scope and timing for this work will be addressed starting with the RIP.

Based on the assessments undertaken by the IESO, the IRRP Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV transmission reinforcement project, including initiating community engagement, the EA, and OEB Section 92 Application for Leave to Construct.

Supply capacity at Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section

These regional capacity needs do not emerge until between 2030 and 2040, depending on the assumptions around continued gains in energy efficiency resulting from efficiency codes and standards.

Leaside TS and Manby TS needs are related to the 230 kV/115 kV autotransformer capacity limits. The Manby TS to Riverside Junction line needs are related to the ability to supply the demand when there is a loss of a companion circuit. The Bayview Junction to Balfour Junction needs emerge in 2040 and are related to the thermal rating of the 115 kV circuit, when there is a loss of the companion circuit.

Cost-effective NWAs, including DERs and energy efficiency, remain possible options to address each of these longer-term regional supply capacity needs. Ongoing engagement with stakeholders and the community will be important for understanding the potential for these types of options going forward. It will also be essential to gather enough information on the nature and timing of these needs to understand what performance and cost attributes NWA options will be required to address them.

7.4 Options for Addressing Discretionary Reliability Needs

These needs are included in Appendix D as discretionary because they represent possible opportunities to maintain and/or enhance the reliability of supply above the minimum performance standards prescribed in ORTAC. Their inclusion in this IRRP recognizes the importance of a reliable electricity supply to an urban centre like Toronto, should feasible, cost-effective options for improving reliability emerge as an outcome of continued planning, coordination, and engagement with electricity sector stakeholders and the community.

Although no specific solution options have been explored in the scope of this plan, these issues should be revisited in future plans, or as other opportunities arise to assess the adequacy and/or resilience of the system, including when assets approach their end of life.

7.5 The Recommended Plan

This IRRP re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address region's transmission needs until at least the late 2020s or early 2030s.

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

Both of these overhead line sections were deemed critical for maintaining a sufficient and reliable supply of electricity to customers in Toronto. The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

Both transformers at Main TS are at their end of life and need to be replaced. Considering the potential for future high density urban development in the area, the Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

When this regional plan was initiated, Hydro One was well into developing options to replace the existing C5E/C7E underground 115 kV cables running between Terauley TS and Esplanade TS in the downtown core. The Working Group recommends that Hydro One continue planning to replace the existing 115 kV cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: Planning for replacement of these critical electricity assets is a major undertaking that must consider a variety of factors and requires regional coordination. The Working Group recommends that detailed planning for the end of life of these assets continue, starting with the RIP.

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires solutions to address the need. It is expected that this work will involve engaging with key stakeholders, including the City of Toronto and entities responsible for development in the Basin TS area.

If better information about the timing and nature of power system needs in the area indicates there is an urgent need, then Toronto Hydro will inform the Working Group of the need to initiate the next regional planning cycle early.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

This IRRP re-affirms the need for the Richview TS to Manby TS 230 kV corridor reinforcement that was recommended in the previous regional planning cycle. The Working Group therefore recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the EA to ensure that the reinforced corridor is in-service as soon as possible.

Keep options available to address long term regional supply capacity needs

The IESO will monitor peak demand annually, along with achievement of energy efficiency and DER uptake, with a particular focus on the areas with forecasted capacity needs. This information will be used to determine when decisions on the long term plan are required, and to inform the next cycle of regional planning for the area. This work will include detailed planning and community engagement to define the needs and associated timing in a manner that will permit the evaluation of possible NWAs as solutions.

The Working Group therefore recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to define and communicate, as soon as practicable, the longer-term capacity needs; identify opportunities for a range of cost-effective solutions, including DERs and energy efficiency; and identify potential wires solutions and avoidable costs should these needs be deferred through NWAs. The information and insights developed through these activities will be used to inform the next regional planning cycle.

7.5.1 Implementation of Recommended Plan

To ensure that the near term electricity needs of the Toronto region are addressed, plan recommendations will need to be implemented as soon as possible. Specific actions and deliverables are outlined in Table 7-4, along with the recommended timing.

Table 7-4: Summary of Needs and Recommended Actions in Toronto Region

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
End-of-life of overhead line sections H1L / H3L / H6LC / H8LC and L9C / L12C	Proceed with replacement as needed to meet identified timelines	Hydro One	2022-2033 for HxL/HxLC circuits; 2023-2024 for LxC circuits
End-of-life of Main TS transformers, 115 kV disconnect switches and 115 kV current voltage transformers	Proceed with replacement as needed to meet identified timelines	Hydro One	2021-2022
End-of-life of C5E / C7E underground transmission cables	Continue with EA, and proceed with replacement to meet identified timelines	Hydro One	2024-2025
End-of-life assets at Manby TS, John TS and Bermondsey TS	Continue with detailed planning to make a decision in time to address the need; initiate in the Regional Infrastructure Plan	Working Group	2025-2027
Capacity to supply projected load at Manby TS	Continue with implementation of Horner TS expansion to provide relief	Hydro One	2021
Capacity to supply projected load at Basin TS	Continue to gather information to inform assessment of future need and timing; engage with key stakeholders; trigger regional planning if necessary	Toronto Hydro	2019 to next planning cycle
Richview to Manby TS 230 kV reinforcement	Initiate EA work, community engagement, and OEB Section 92 Application	Hydro One	2021 or as soon as possible

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Leaside TS and Manby TS autotransformer capacity; Manby TS to Riverside Junction; and Bayview Junction to Balfour Junction	Further define characteristics of longer-term needs; define information needed from local stakeholders; identify DER and energy efficiency potential; develop wires-based alternatives; assess and compare wires and NWAs	IESO	2019 to next planning cycle

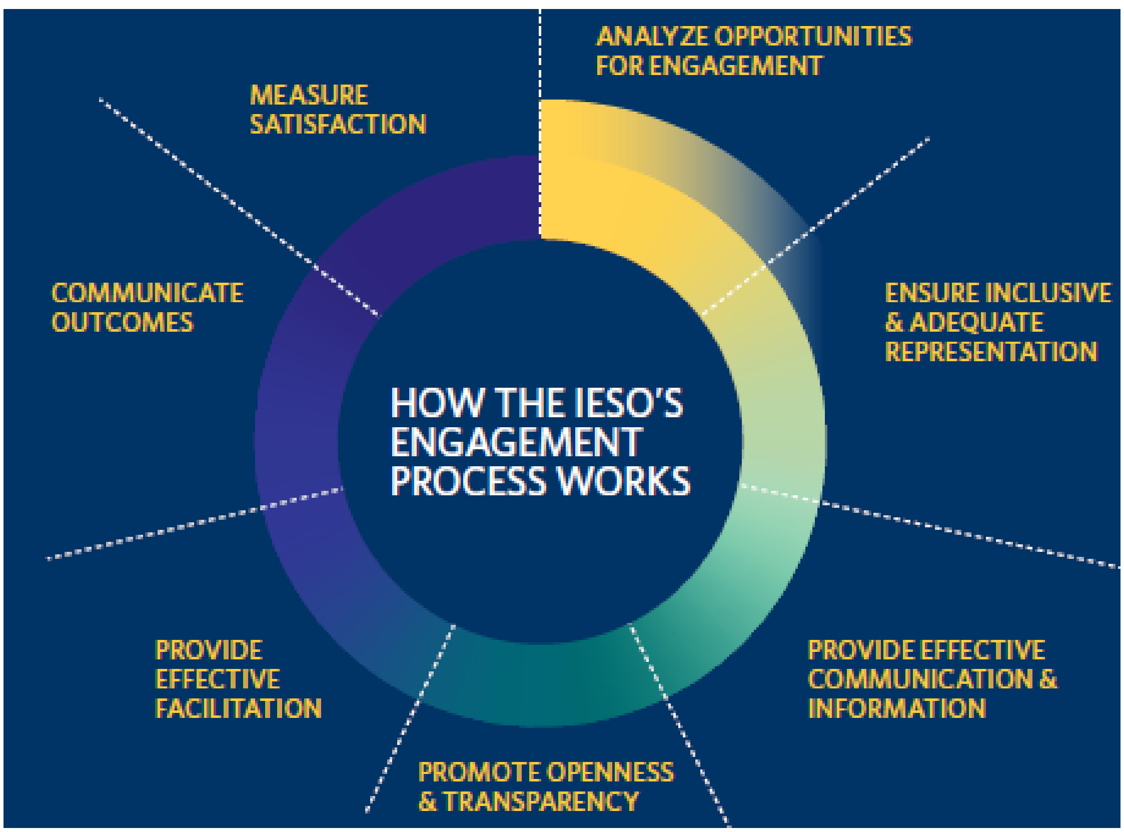
8. Community and Stakeholder Engagement

Community engagement is an integral component of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken for the Toronto IRRP.

8.1 Engagement Principles

The IESO's Engagement Principles[23] guided the process to help ensure that all interested parties were aware of and could contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and to support its efforts to build trusted relationships.

Figure 9-1: IESO Engagement Principles



[23] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 Creating an Engagement Approach

The outreach and engagement approach was designed to ensure the IRRP reflected input from key community and stakeholder representatives. A dedicated engagement web page[24] was also created to provide openness and transparency throughout the engagement process. This web page hosted all engagement activities, including background information, presentations and public meetings/webinars on the development of this IRRP, as well as previous plans for the area.

The IESO's email subscription service for the Toronto planning region was used to send information to interested communities and stakeholders who subscribed to receive updates. Targeted outreach to municipalities, Indigenous communities and other business sectors in the region was also conducted at the outset of this engagement and continued throughout the planning process.

In addition, regular communications were sent via the IESO's weekly Bulletin, which has subscribers from across Ontario's electricity sector.

8.3 Engage Early and Often

Leveraging relationships built during the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach during this second planning cycle – starting with the Scoping Assessment Outcome Report.

Early communication and engagement activities for the Toronto IRRP began with invitations to all subscribers and targeted communities to learn about and provide comments on the draft Toronto Region Scoping Assessment Outcome Report before it was finalized in February 2018. This scoping assessment identified the need for an IRRP for the Toronto region and included terms of reference to guide development of the plan. Following feedback, and the IESO's response to feedback – both of which are posted on the engagement web page – the final Scoping Assessment Outcome Report was also published.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP. The launch of a broader engagement initiative followed with an

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[24] http://ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Toronto

invitation to subscribers to ensure that all interested parties were made aware of this opportunity for input.

A public engagement meeting, held to give interested parties an opportunity to learn about the draft IRRP and provide comments, attracted a cross-representation of stakeholder and community representatives. Following a 14-day comment period, no further comments were received for consideration during the development of the IRRP.

As a final step in this engagement, all participating parties were invited to comment on the proposed recommendations in this IRRP. Comments received during the engagement meeting and in response to the proposed recommendations related to six major themes:

1. Non-wires alternatives
2. Considerations to inform future electricity needs in electricity system planning
3. Electrification (e.g., electric vehicles)
4. Costs of the electricity system
5. Composition of the technical working group
6. Engagement/education

Based on this feedback, it is clear that there is a strong need for ongoing monitoring of capacity and local demand growth, as well as continued discussion and engagement with communities and stakeholders. While needs do not start to emerge until the 2030s or later, the IESO recognizes the importance of sustained dialogue to ensure alignment with local priorities, initiatives and developments. The full submissions can be found on the IESO's website. Reponses to specific feedback are provided as Appendix G: Responses to Public Feedback on Proposed Recommendations.

All background information, including engagement presentations and recorded webinars, are available on the IESO's Integrated Regional Resource Plan engagement web page.

8.4 Outreach with Municipalities

As the City of Toronto was a key stakeholder in the development of this IRRP, the IESO held a number of meetings with city representatives to seek input on municipal planning and to ensure that the city's plans were taken into consideration. Meetings began in June 2018 at the outset of these discussions and continued in April and May 2019. These meetings helped to inform the city's electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9. Conclusion

This report documents an IRRP that has been developed for the Toronto region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability in Toronto from 2019 to 2040. The IRRP makes recommendations to address near term issues, and lays out actions to monitor, defer, and address long term needs.

To further review "wires" solutions that address end of life asset replacement and other transmission supply needs, the Working Group recommends that Hydro One initiate an RIP. The IESO will continue to provide input and support throughout the RIP process, and assist with any regulatory matters arising during plan implementation.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, monitoring load growth and efficiency achievements, and evaluating DER potential and value in the region. Responsibility for these actions has been assigned to the appropriate members of the Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional plan for the Toronto region.

The Toronto region Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Toronto Region Scoping Assessment Outcome Report

March 21, 2023

Connecting Today.
Powering Tomorrow.

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of regional planning for the Toronto region, and it was initiated in fall 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Technical Working Group (TWG) led by Hydro One. The Needs Assessment Report was finalized on December 19, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Technical Working Group reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region, including the recent Pathways to Decarbonization report.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a Regional Infrastructure Plan (RIP) – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals;
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Transmission)
- Toronto Hydro Electric Systems Limited (Toronto Hydro)
- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

3. Categories of Needs, Analysis and Results

3.1 Overview of the Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

In addition to the transmission infrastructure described above, the Portlands Energy Centre (550 megawatt [MW] summer capacity) is a natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS) shown in Figure 1.

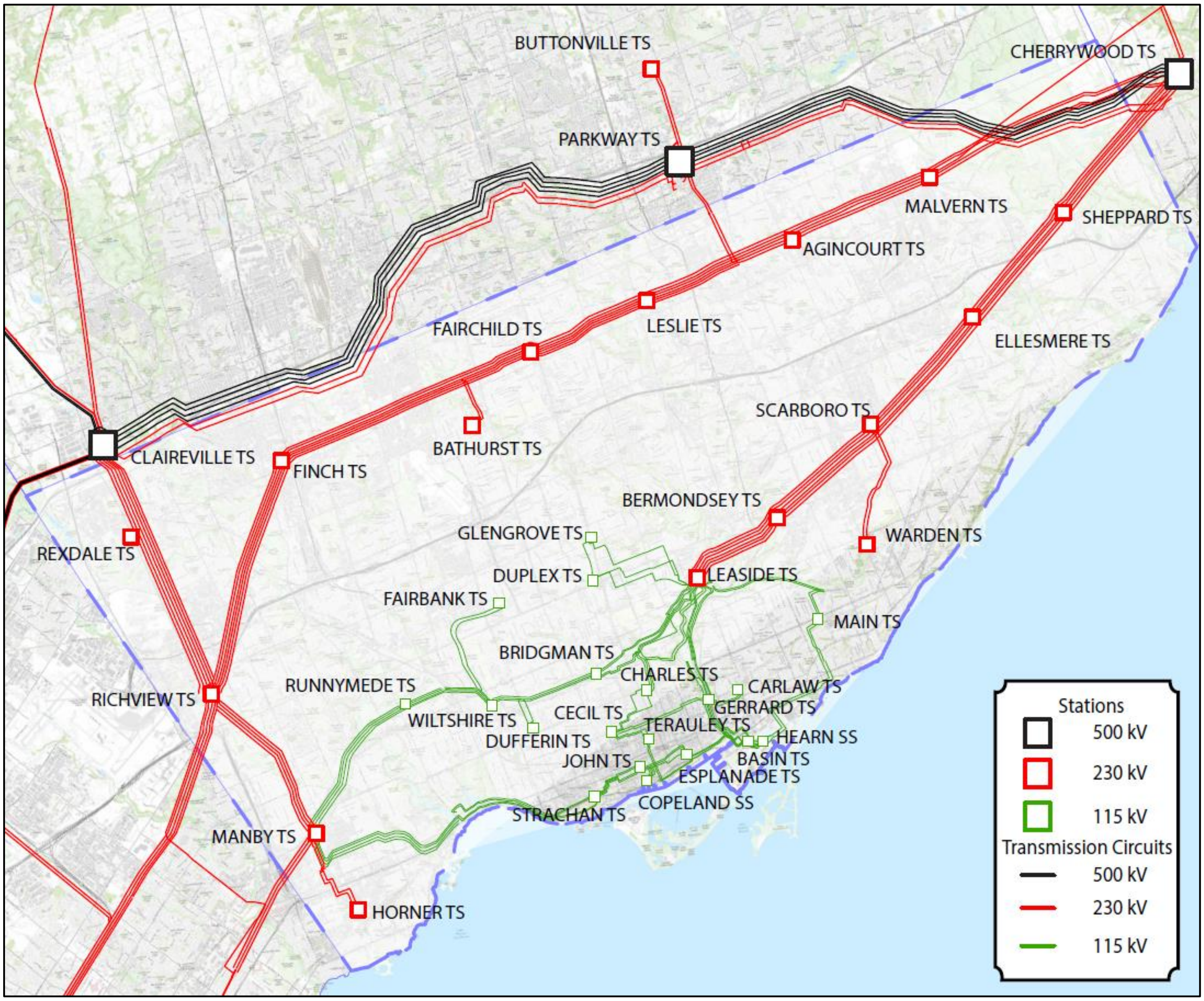
Numerous distributed energy resource (DER) facilities are located throughout the City. For example, through previous procurements such as the Feed-in Tariff program, Renewable Energy Standard Offer Program, and Combined Heat and Power (CHP) Standard Offer Program, approximately 1,900 individual renewable and CHP facilities have been placed in service in the City of Toronto. The total combined electrical supply capacity of these DERs is 106 MW.[1]

The region is summer peaking and the 2022 peak summertime electricity demand in the Toronto region was approximately 4,400 MW.[2]

[1] This translates to about 40 MW of "effective" capacity that system planners can count on during the peak demand period (assuming 34% capacity factor for solar PV, 13.6% for wind, and 100% for all other fuel types, including CHP).

[2] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

Figure 1 | Electricity Infrastructure of the Toronto Region



3.1.1 Indigenous Communities

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council (HCCC) and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for the Toronto region was formally completed in January 2016 with the publication of Hydro One's Regional Infrastructure Plan (RIP) for the Central Toronto area, following the publication of an IRRP for Central Toronto in April 2015. In February 2017, an update was published to reflect plans to convert commuter heavy rail (Metrolinx - GO) from diesel to electric power.

In mid-2017, Hydro One identified a number of transmission asset renewal needs in Toronto over the next ten years. The scale and timing of these needs necessitated the initiation of another regional planning cycle. Hydro One initiated a Needs Assessment, which officially started the next regional planning cycle for the region. The Needs Assessment was completed in October 2017, and subsequent Scoping Assessment was completed in 2018. An IRRP was initiated in 2018, and released in 2019. This plan focused on transmission asset renewal needs, and preparing to address local and regional capacity needs emerging in the longer term.

The second round of regional planning for the Toronto region was completed in March 2020, with the release of the Hydro One led RIP.

An updated analysis for the Richview to Manby Upgrade project (now known as the "Etobicoke Greenway Project") was conducted in 2021. This analysis reaffirmed the findings in the 2019 IRRP and 2020 RIP and recommended the project go ahead.

3.3 Needs Identified

For this third cycle of regional planning, Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Toronto region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway or Complete to Address Previously Identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation for the options recommended to address them (see Table 1). These projects provide a starting point for future assessments and will be accounted for in this planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Need	Solution and Timing
Copeland TS Phase 2, address capacity need	In-service 2024
Bridgman TS transformer replacement (T11, T12, T13, T14)	Expected completion 2024

Need	Solution and Timing
Fairbank TS transformer replacement (T1, T2, T3, T4)	Expected completion 2024
Main TS transformer replacement (T3, T4)	Expected completion 2024
John TS transformer replacement (T5, T6)	Expected completion 2025
C5E/C7E underground cable replacement between Esplanade TS and Terauley TS	Expected completion 2026
Richview TS to Manby TS 230 kV Corridor Upgrade	Expected completion 2026

Since the previous regional planning cycle, the following additional projects have also been implemented by Hydro One:

- Second DESN at Horner TS, complete 2022
- Refurbishment projects at Runnymede TS (T3, T4), Sheppard TS (T3, T4), and Strachan TS (T12), complete 2021-2022
- Replacement of John TS transformers (T1, T2, T4), complete 2019-2021

3.3.2 Needs Requiring Further Coordination or Study in the Current Planning Cycle

The Needs Assessment then identified new or updated needs in the Toronto region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Several of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 2). However, many may still require a significant amount of planning or have a shared impact with other system assets or needs. For example, any needs dealing with major right of ways, even routine maintenance or like-for-like replacement, may have an impact on shared, downstream, or alternate facilities. Stepdown station asset renewal needs can also be linked to broader needs, if the station is located within a rapidly growing or supply constrained area. These types of needs do not require coordinated study through an IRRP, but should still be considered in scope of further regional planning activities to ensure that outage schedules and other shared impacts are appropriately accounted for.

Table 2 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Richview TS to Manby TS 230 kV Corridor[3]	• Line Capacity Need
2	Manby TS, autotransformers (T7, T9, T12)[4] and step-down transformers (T13/T14)	• Asset renewal need
3	115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	• Asset renewal need
4	115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section	• Asset renewal need
5	Strachan TS: T14 & T13/T15	• Asset renewal need
6	Charles TS: T3/T4	• Asset renewal need
7	Duplex TS: T1/T2 & T3/T4	• Asset renewal need
8	Basin TS: T3/T5	• Asset renewal need
9	Scarboro TS: T23	• Asset renewal need
10	Fairchild TS: T1 & T3/T4	• Asset renewal need
11	Bermondsey TS: T3/T4	• Asset renewal need
12	Malvern TS: T3	• Asset renewal need
13	Fairbank TS	• Station Capacity Need
14	Strachan TS	• Station Capacity Need

[3] Further regional planning is not required as the project was recommended in the previous cycle of regional planning. Hydro One is developing the project, with an expected in-service date of mid-2026.
[4] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity in Toronto as a whole will be assessed in the upcoming IRRP.

The remaining needs, which were determined through the Needs Assessment to require further coordinated study are listed in Table 3. Most needs deal directly with capacity constraints, or load restoration, as a range of solutions may be considered and the impact on broader system operation would need to be evaluated. Note that some step down station capacity needs (Fairbank TS and Strachan TS) were not included in this list, as solutions to address needs have already been identified.

Table 3 | Needs identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need
1	115 kV Manby TS to Riverside Jct. Corridor	• Line capacity need
2	230 kV Parkway TS to Richview TS Corridor	• Line capacity need
3	115kV Leaside TS to Wiltshire TS Corridor	• Line capacity need
4	230/115kV Manby W Autotransformers[5]	• Autotransformer capacity need
5	230/115kV Leaside TS Autotransformers	• Autotransformer capacity need
6	Sheppard TS	• Station capacity need
7	Basin TS	• Station capacity need
8	Glengrove TS	• Station capacity need
9	Finch TS / Bathurst TS	• Station capacity need
10	Warden TS	• Station capacity need
11	Loss of C14L/C17L	• Load restoration need
12	Loss of C18R/P22R	• Load restoration need

[5] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity will be looked at in the upcoming IRRP.

3.3.3 Analysis of Needs and Identification of Region

The Technical Working Group (TWG) has discussed the needs in the Toronto region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The participants agreed that for each of the identified needs requiring further study, a range of alternatives including wires and non-wires solutions should be assessed. Additionally, several needs were identified which do not require further coordinated planning, but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area. These include needs whose previously recommended solutions are already underway, and asset renewal needs with the potential to affect overall capacity needs in the area.

Based on discussions, it was agreed that an IRRP should be undertaken to further assess these needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the IRRP is attached in Appendix B.

The participants also agreed, for the purpose of the next regional plan, that the City of Toronto should not be divided into sub-regions. While most of the needs identified impact electricity infrastructure in the downtown area, some needs have been identified in other parts of Toronto, outside of the central part of Toronto.

Lastly, because none of the needs identified directly impact facilities that supply customers of Alectra Utilities Corporation, Elexicon Energy Inc., or Hydro One Distribution, it was agreed that the core Working Group for the IRRP will include the IESO, Toronto Hydro, and Hydro One Transmission. The other utilities will be informed and invited to participate if any needs, or proposed solutions, may affect their facilities or customers.

3.3.4 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[6] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[7]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

3.3.5 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including

[6] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[7] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, the Terms of Reference for the Toronto IRRP may be amended at a future time to account for additional objectives, activities, and assumptions required to align deliverables with new provincial direction.

3.3.6 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the Toronto region;
- No sub-regions within Toronto will be created for the IRRP; the region should be treated as a whole for the purpose of developing a comprehensive plan;
- The implementation of recommendations from the previous planning cycle should continue;
- The composition of the IRRP Working Group will include the IESO, Toronto Hydro, and Hydro One Transmission. Other Local Distribution Companies in the region will be informed of any needs or solutions that may affect their facilities or customers;
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required;
- In addition to addressing the needs identified in the Needs Assessment, two focus areas will be examined in detail in the IRRP: Port Lands and Downsview;
- The Toronto IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- The IESO may amend the Terms of Reference for the Toronto IRRP as required to align with provincial direction following consultation related to the Pathways to Decarbonization Report.

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Toronto IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – Toronto Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Toronto region.

Based on the power system needs identified throughout the region (including a number of transmission stations and lines requiring replacement based on asset condition assessment in the near term and medium term), strong urban growth and intensification projections in the City of Toronto, expansion of electrified transit, and potential demand and resource pressures from decarbonization policies, an IRRP is the appropriate planning approach for this region.

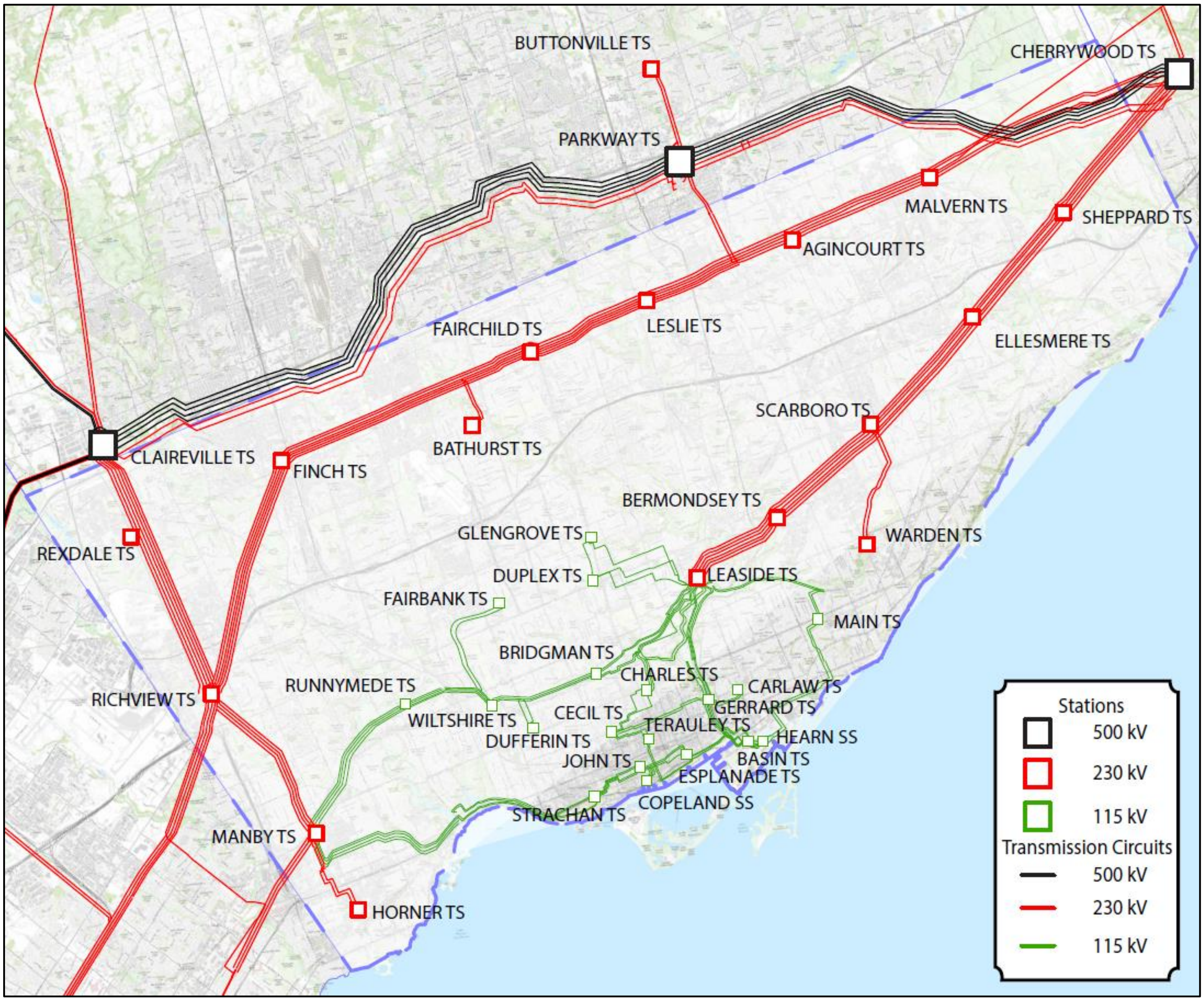
1.1 The Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 2. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

For the purpose of this IRRP, no divisions are proposed that would create any sub-regions to assess within the City of Toronto.

Figure 2 | Electricity Infrastructure of the Toronto Region



1.2 Background

In December 2022, Hydro One completed the Needs Assessment report for the Toronto region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP is ultimately recommended on the basis of the scale of load growth anticipated, potential for diverse types of solution (including wires and non wires), and long term uncertainty associated with city development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[8] that provides electricity supply to the Toronto region over the next 25 years.[9]
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the Toronto region. The plan is a joint initiative involving Toronto Hydro, Hydro One Transmission, and the IESO,[10] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The scope of the Toronto IRRP includes the following needs, as identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
115 kV Manby TS to Riverside Jct. Corridor	Line capacity need	2028
230 kV Parkway TS to Richview TS Corridor	Line capacity need	Beyond 2031
115kV Leaside TS to Wiltshire TS Corridor	Line capacity need	Beyond 2031
230/115kV Manby W Autotransformers	Autotransformer capacity need	Beyond 2031

[8] The scope of the assessment includes transmission stations.

[9] The typical planning horizon in a regional study is 20 years; however, Toronto Hydro produces a long-range forecast spanning 25 years and this forecast will be used as the basis for assessing long-term system needs in the IRRP.

[10] Alectra Utilities, Elexicon Energy Inc. and Hydro One Distribution are also supplied by feeders from Toronto. These utilities will not form part of the core Technical Working Group. However, they will be informed of any developments that may impact their facilities and/or customers.

Facilities	Type of Need	Expected Timing
230/115kV Leaside TS Autotransformers	Autotransformer capacity need	Beyond 2031
Sheppard TS	Station capacity need	Beyond 2031
Basin TS	Station capacity need	Beyond 2031
Glengrove TS	Station capacity need	Beyond 2031
Finch TS / Bathurst TS	Station capacity need	Beyond 2031
Warden TS	Station capacity need	Beyond 2031
Loss of C14L/C17L	Load restoration need	2031
Loss of C18R/P22R	Load restoration need	2031

Other identified needs in the Needs Assessment not listed in Table 4 above will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

3.2 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[11] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[12]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

[11] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[12] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

3.3 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, this Terms of Reference may be amended at a future time to account for additional objectives, activities, and assumptions required to align the Toronto IRRP deliverables with new provincial direction.

3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Activities

The IRRP process will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table 5 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand forecast to be used.

1) Develop an electricity demand forecast for the Toronto region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.

7) Develop a long-term plan for the electricity system in Toronto to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in Toronto could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident and non-coincident peak demand information and trends for the region
  - Historical weather correction, for median and extreme conditions
  - Gross peak demand forecast scenarios by TS, etc.
  - Coincident peak demand data
  - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
  - LDC CDM plans
  - Incorporation of verified LDC results and other CDM programs/opportunities in the area
  - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
  - Conservation potential studies, if available
  - Potential for CDM at transmission-connected customers' facilities, if applicable
  - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
  - Local building codes, energy performance requirements, etc.

- Local resources
  - Existing local generation resources, including distributed energy resources (DER), district energy resources, customer-based generation, as applicable
  - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
  - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans
  - City policies with an impact on electricity usage, including TransformTO
  - Municipal Growth Plans
  - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Ontario Line), and transit electrification (e.g. GO train electrification)
  - Pathways to Decarbonization Report

- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability

        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- Asset renewal considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Toronto Hydro Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Transmission)

The following LDCs will not be part of the IRRP Technical Working Group but will be informed of any developments that may impact their facilities and/or customers:

- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Toronto IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 5 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	March 2023
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q2-Q4 2023
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	Toronto Hydro		
d. Establish existing, committed, and potential DG	IESO, Toronto Hydro		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	Toronto Hydro/ Hydro One	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	Toronto Hydro, communities, stakeholders, and IESO	Relevant community plans	Q1 2024
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q2 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the LMC of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and Toronto Hydro		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and Toronto Hydro		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and Toronto Hydro		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and Toronto Hydro		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q2-Q3 2023
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and Toronto Hydro		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and Toronto Hydro		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and Toronto Hydro		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1-Q2 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	September 2024

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Powering Tomorrow.

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NEEDS ASSESSMENT REPORT

GTA North Region

Date: July 14, 2023

Prepared by: GTA North Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

Region	GTA North Region (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	March 17, 2023	**End Date**	July 14, 2023

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in March 2023 for the GTA North Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA North Region NA includes:

a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment.
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon.

The provincial push towards decarbonization as outlined in the IESO's "Pathways to Decarbonization" report published on December 15, 2022, is expected to impact the electricity demand over the longer term. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than previously anticipated or as discussed in this report. The impact of decarbonization will be considered during the next phases of this regional planning cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation, and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast and variability of demand drivers such as electrification.

6. NEEDS

Needs that were identified in the last RP cycle with current need dates are as follows:

- New Markham MTS #5 – need date is 2028
- Uprate 230kV circuits P45/46 from Parkway TS to Markham MTS #4 Jct. – need date is 2028
- New Northern York TS - need date is 2027
- Woodbridge TS: Replace transformer T5 with similar and size equipment as per current standard – need date is 2027
- New Vaughan MTS #5 – need date is 2030
- Claireville TS x Brown Hill TS Transmission circuit capacity need – need date is 2030
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P – Existing need[1]

New needs identified in this NA are:

- Kleinburg TS 44kV: Load transfer to Northern York TS – need date is 2027
- New Vaughan MTS #6 – need date is 2027
- New Toubner TS (CTS) – need date is 2027
- New Richmond Hill MTS #3 – need date is 2032
- Load Restoration needs for 230kV circuits P45/P46 – need date is 2027

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need and work will be proceeding as planned:
   - Woodbridge TS: Replace transformer T5
   - Toubner TS: Build new station
   - Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
   - Kleinburg TS 44kV: Load transfer to Northern York TS
   - Markham MTS #5: Build new station
   - 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
   - Northern York TS: Build new station
   - Vaughan MTS #5: Build new station
   - Richmond Hill MTS #3: Build new station
   - Claireville TS x Brown Hill TS Transmission circuit capacity need and load restoration needs
   - Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P

1. No action considered was considered necessary in the last regional planning cycle

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1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update previously identified needs in the last GTA North RP cycle, and recommend which needs require further assessment and regional coordination.

This report was prepared by the GTA North Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDCs") and the Independent Electricity System Operator ("IESO").

Table 1-1: GTA North Region TWG Participants

Company
Alectra Utilities Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Newmarket-Tay Power Distribution Ltd
Toronto Hydro-Electric System Limited ("THESL")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the GTA North Region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- Reaffirm and update needs/plans identified in the previous RP cycle.
- Identify any new needs resulting from this assessment.
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
- Recommend which need(s) that do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is comprised of the Northern York Area, Southern York Area, and the Western Area. Electrical supply to the region is provided from sixteen 230kV step-down transformer stations. The 2022 Summer Peak area load of the region was approximately 2249MW. Please refer to Figure 4-1.

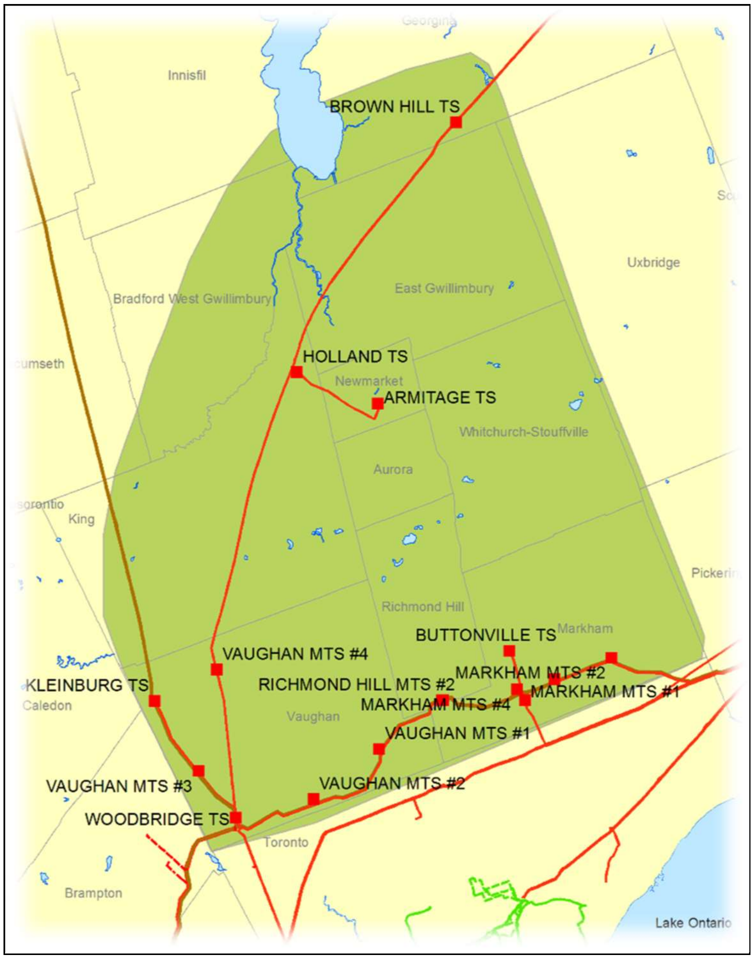


Figure 4-1: GTA North Region Map

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Please refer to Figure 4-2.

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

The Southern York Area includes the municipalities of Vaughan, Markham, and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight LDC owned stations and one Hydro One owned) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is Alectra.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one LDC owned transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro.

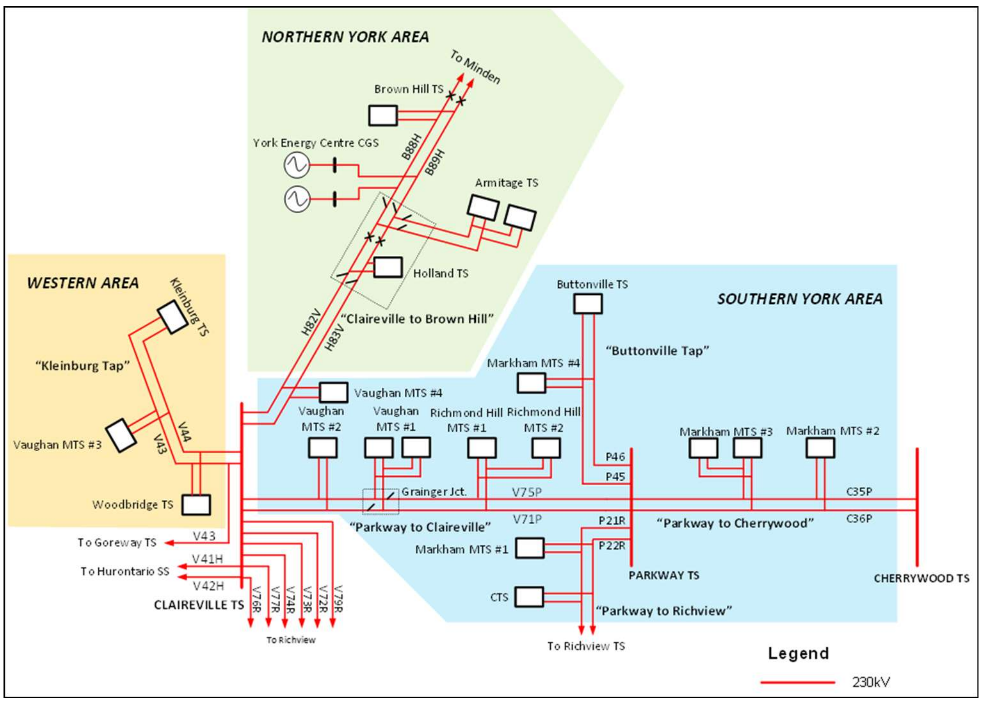


Figure 4-2: GTA North Region– Single Line Diagram

The transformer stations and circuits in the area are listed in Appendix A and Appendix B.

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

- Load Forecast for all supply stations in the GTA North Region.
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the GTA North RP process.

In December 2022, the IESO published a report [1] on developing an achievable pathway to the decarbonization of the electricity system. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than anticipated or discussed in this report. The impact of the decarbonization and resulting electrification will be considered during the next phase of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the GTA North Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station was prepared by applying the growth rates from the LDC load forecast to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. The extreme summer weather corrected net non-coincident peak for the individual stations in the GTA North Region are given in Appendix C.
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment.
- System reliability and operational considerations.

[1] IESO Report, "Pathways-to-Decarbonization", Dec15, 2022

- Asset renewal for major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
- Sensitivity analysis to capture uncertainty in the load forecast

The following other assumptions are made in this report.

- The study period for this NA is 2023-2032.
- Coincident loads have been assumed equal to non-coincident loads for the purpose of transmission line adequacy assessment.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 ADEQUACY OF EXISTING FACILITIES

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest extreme weather peak summer regional load forecast provided in Appendix C.

7.1 Adequacy of Northern and Southern York Area Facilities

7.1.1 500 and 230 kV Transmission Facilities

All 500 and most 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 4-2.

Northern York Area:

- Claireville TS to Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

Southern York Area:

- Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
- Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
- Parkway TS to Buttonville TS ("Buttonville Tap") 230 kV circuits: P45 and P46[2].
- Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Western Area:

- Claireville TS to Kleinburg TS 230 kV circuits: V43 and V44[3]

The NA review shows that all flows on all transmission lines are within rating during the 2023-2032 study period except for the Claireville x Brown Hill corridor and the Parkway TS to Buttonville TS line. These are discussed below:

1) Loading on the Claireville TS to Brown Hill TS 230kV Corridor comprising the double circuit line H82/H3V and B88H/B89H will exceed the thermal limits by summer 2030.

[2] Radial from Parkway TS
[3] Radial from Claireville TS

Table 7-1 Loading on Claireville TS x Brown Hill TS Corridor

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Armitage TS (44kV)		285	290	296	301	305	303	305	308	311	313	
Brown Hill TS (44kV)		94	100	118	121	125	124	125	125	126	126	
Holland TS (44kV)		166	173	176	179	169	169	169	169	169	169	
Northern York Station						66	80	89	99	109	118	
Vaughan MTS #4 (28kV)		101	100	128	149	148	147	146	145	143	142	
Vaughan MTS #5 (28kV)									64	132	138	
Total	850	646	663	718	750	813	823	834	911	989	1007	2030

2) Loading on the Parkway TS x Markham MTS #4 Jct. section of the 230kV Parkway TS x Buttonville TS double circuit Line P45/P46 will exceed the rating of line by summer 2028

Table 7-2 Loading on the Parkway TS x Markham MTS #4 Jct. Section of 230kV Line P45/P46

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Buttonville TS (28kV)		144	152	154	152	160	149	148	147	146	145	
Markham MTS #4(28kV)		116	117	141	162	191	177	175	174	173	171	
Markham MTS #5(28kV)							68	136	140	139	138	
Toubner TS (28kV)						32	31	50	52	55	72	
Total	420	260	269	294	314	384	425	509	513	513	526	2028

7.1.2 Step down Transformer Station Facilities

There are a total of fifteen Hydro One and LDC owned step-down transformers stations and one direct transmission connected industrial customer owned station in the GTA North Region as given in Table 7-3 Step-Down Transformer Stations in the GTA North Region below:

Table 7-3 Step-Down Transformer Stations in the GTA North Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1[1]	Markham MTS #2[1]
Markham MTS #3[1]	Markham MTS #4[1]	Richmond Hill MTS[1]
Vaughan MTS #1[1]	Vaughan MTS #2[1]	Vaughan MTS #4[1]
Industrial Customer		
Western Area		
Kleinburg TS	Vaughan MTS #3[1]	Woodbridge TS

1. Stations owned by Alectra

The loadings on these stations were reviewed. Based on the forecast in Appendix C, additional capacity is required in the Northern York, Markham, and Vaughan areas starting in 2027. The station loading in each area and the associated station capacity and need dates are summarized in Table 7-**.**

Table 7-4 Adequacy of the Step-Down Transformation Facilities in the GTA North Region

Area/Supply	LTR-Capacity (MW)	2023 Summer Forecast (MW)	Need Date
Northern York Area (Armitage TS, Holland TS)	485	452	2027
Northern York Area (Brown Hill)	184	94	-
Markham / Richmond Hill transformation Capacity (Buttonville TS, Markham MTS #1, 2, 3, 4, and Richmond Hill MTS #1, 2)[1]	957	847	2028
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	551	2030
Vaughan Transformation Capacity (Vaughan MTS #3)[2]	153	145	2027
Kleinburg Area (Kleinburg TS 44kV)	97	102	Note [3]
Woodbridge TS (44kV)	80	85	Note [4]

1. Two stations required Markham MTS #5 in 2028 and Richmond Hill MTS #3 in 2032
2. Vaughan MTS #6 is a station dedicated for a large customer.
3. Excess load to be transferred to Northern York TS when new station complete in 2027
4. Loads to be managed by Hydro One Distribution

7.2 Asset Renewal Needs

No asset renewal needs have been identified in the GTA North Region over the current study period other than replacement of transformer T5 at Woodbridge TS listed in the 2020 RIP.

7.3 Load Restoration and Load Security Needs

Load Restoration and /or security needs were identified for theV43/V44, H82V/H83V, and V71P/V75P circuits in the 2020 RIP. One new load restoration need has been identified for the P45/P46 circuits. The needs and the recommended plan to address them are summarized below:

1. <u>Load restoration following loss of the Claireville TS x Kleinburg TS 230kV circuits (V43/V44).</u>

Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively, as per the ORTAC restoration criteria. The RIP recommended that this need would be addressed as part of the longer-term plan to reinforce the Claireville TS to Kleinburg TS corridor. No further action was proposed at the time. This will be re-visited in the next phase of this RP cycle.

2. <u>Load Restoration following loss of the Claireville TS to Holland TS circuits (H82V/H83V).</u>

All loads exceeding 250 MW cannot be restored within 30 minutes per the ORTAC criteria. Following the loss of H82V/H83V, the normal station service supply to YEC generation is also lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. The RIP had recommended that the IESO pursue alternative station service configurations at YEC to facilitate faster restoration of load on H82V/H83V, consistent with the load restoration criteria. This will be re-visited in the next phase of this regional planning cycle.

3. <u>Load Security Need for the Parkway TS to Claireville TS 230kV double circuit Line V71P/V75P</u>

The loss of this line can result in an interruption to over the 600MW which is more than what is permitted under the ORTAC criteria. The RIP had recommended that no further action is required. While the load security criteria was not met, Hydro One has installed inline switches at Grainger Jct. – located just outside of Vaughan MTS #1 - which permits quick restoration of the loads. This will be re-visited in the next phase of this regional planning cycle.

4. <u>Load Restoration Need for the Parkway TS to Buttonville TS 230kV double circuit Line P45/P46</u>

The line loading is expected to reach 384MW by summer 2027. Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively for a double circuit outage, as per the ORTAC restoration criteria. This is a new need and will be reviewed in the next phase of this regional planning cycle.

8 NEEDS

This section identifies any new needs in the GTA North Region and reaffirms and provides an update on the needs already identified in the previous RIP.

Table 8-1 Near and Medium Terms Needs in the GTA North Region

No.	Need	Recommended Action Plan	Need Date[1]
Needs as per last RIP[2]			
1	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027
2	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027
3	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS and connect to 230kV circuits P45/P46	2028
4	Increase Capability of 230kV Circuits P45+P46 (supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Uprate circuits P45/46 from Parkway to Markham MTS #4 Jct.	2028
5	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #5	2030
6	Claireville X Brownhill Circuit Upgrade	Uprate circuits- H82/H3V and B88H/B89H	2030
7	Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P[3]	To be reviewed in next phase of this regional planning cycle	Existing
New Needs identified			
8	Kleinburg TS Area	Transfer load to Northern York TS	2027
9	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #6 and connect to 230kV circuit V43/V44	2027
10	Markham Area: New Customer Connection	Build New Toubner TS and line tap to 230kV circuits P45/46	2027
11	Richmond Hill Area: Step-down Transformation Capacity	Build new Richmond Hill #3 MTS	2032
12	Load Restoration for 230kV circuits P45/46	To be reviewed in next phase of this regional planning cycle	2027

1. Need date based on current forecast
2. Please see Reference 1 in Section 11
3. No action was considered necessary for these needs in the last regional Planning cycle. Needs will be reviewed again in the IRRP and RIP phases of this regional planning cycle.

8.1 Station and Transmission Capacity Needs in the Near and Medium Term

As shown in the Table above, the 2020 RIP had identified three new station capacity needs, one in the Markham area designated as Markham MTS #5, the second in the Vaughan Area, designated as Vaughan MTS #5 and the third in the Northern York Area, designated as Northern York TS. Since then, based on the current load forecast and customers' request, the need for three additional stations has been identified over the study period - Richmond Hill MTS #3, Vaughan MTS #6 and Toubner TS.

8.1.1 Markham Area - Build Markham MTS #5 and Uprate circuits P45/P46 -2028

Markham MTS #5 was previously identified to provide additional step-down transformation capacity in Markham-Richmond Hill area and planned to be built adjacent to the Buttonville TS and supplied from the same 230kV Parkway TS x Buttonville TS circuits P45/P46 (See Figure 8-1 below). The new station will have 2 x75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building.

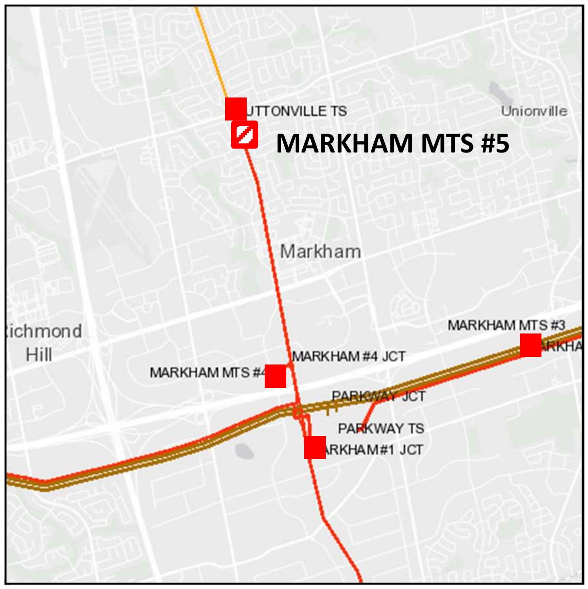


Figure 8-1: Markham MTS #5 Location

The TWG reaffirmed the need to build the new Markham MTS #5 and to uprate the limiting section of the P45/P46 line between Parkway TS and Markham MTS #4 Jct. to provide the needed capacity. The station project need date based on current forecast is summer 2028 (See Table 7-4) and the lines project need date is summer 2028 (see Table 7-2). This will be re-visited in the next phase of this regional planning cycle.

8.1.2 Northern York Region - Build Northern York Area TS and supply from 230kV Line B88H/B89H - 2027

The Northern York Area TS was recommended to be built in the Northern York Region to provide additional step-down transformation capacity in the Bradford, East Gwillimbury, and Newmarket area. This area is currently supplied from Armitage TS and Holland TS and total area load is forecast to exceed the capacity of these existing two stations by summer 2027 as shown in Table 8-2 below.

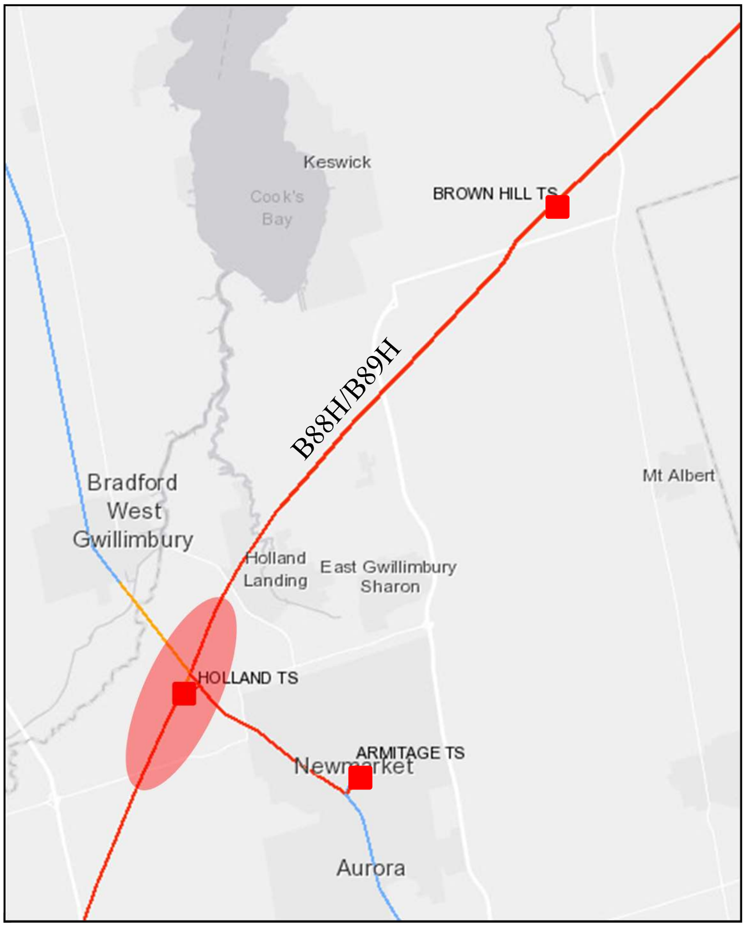


Figure-8-2 Northern York Area TS – Potential Location

Table 8-2: Northern York Area Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Holland TS (44kV)[1]	169	166	173	176	179	169	169	169	169	169	169
Northern York Station	170					66	80	89	99	109	118
Total	485	451	463	472	480	540	552	564	577	589	600

1. Holland load above LTR to be transferred to new Northern York station.

The TWG has reaffirmed the need for building a new station close to these two stations, in the area shown in Figure 8-2. The new station is planned to be supplied from 230kV double circuit line H82V/H83V or B88H/B89H and planned to have 2x75/125MVA, 230/44-27.6kV transformers and 27.6kVand 44kV switchyards. The new station should increase the transformation capacity in Northern York Region by about 170 MW. The station location and timing will be further discussed with the area LDCs in the next phase of the regional planning process.

8.1.3 Vaughan Area – Build Vaughan MTS #5 and supply from 230kV Line H82V/H83V -2030

The Vaughan MTS #5 was previously identified to provide additional step-down transformation capacity in Vaughan area and planned to be built adjacent to the existing Vaughan MTS #4 – see Figure 8-3. The new station is planned to have 2 x75/125MVA, 230/27.6kV transformers, a 27.6kV switchgear building and is planned to be supplied from the 230kV double circuit line H82V/H83V.

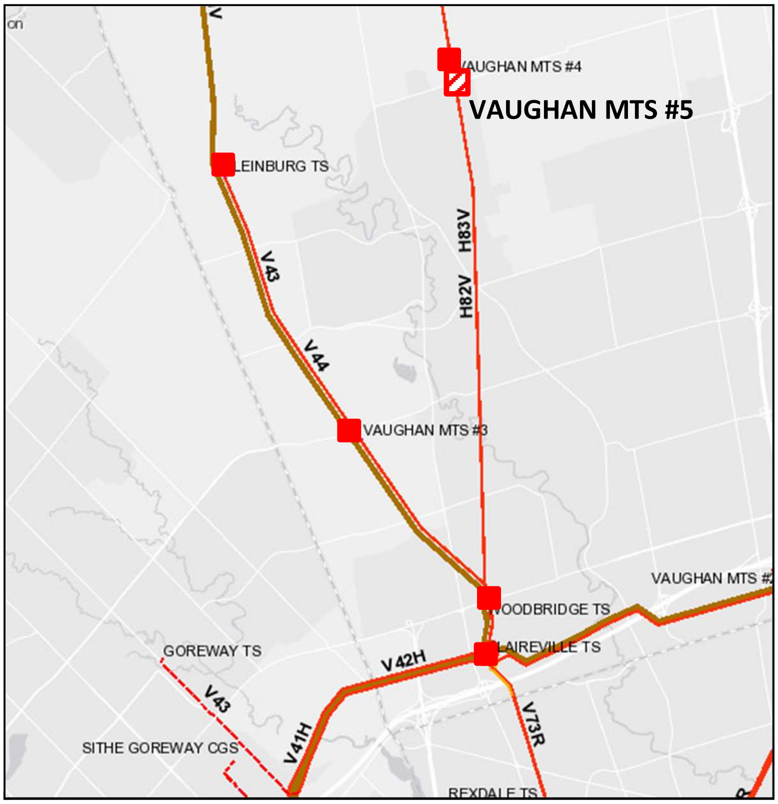


Figure-8-3 Vaughan MTS #5 Location

Table 8-3: Vaughan Area Station Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)									64	132	138
Total	612	551	545	569	585	580	575	570	631	694	696

As mentioned in Table 7-1, there isn't sufficient transmission capacity available on the Claireville to Brown Hill corridor to fully supply Vaughan MTS #5, given that a new station in Northern York is anticipated by 2027. Therefore, a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This will be addressed in the next phase of this regional planning cycle.

8.1.4 Kleinburg TS Area – Transfer Load to Northern York TS

Kleinburg TS 44kV loading is a newly identified need. Kleinburg TS has 2 x 75/125MVA, 230/44-27.6kV transformers with separate 44kV and 27.6kV switchyards. Significant new load is forecast to connect at 44kV in the 2023-2024 period as shown in Table 8-4 below.

Table 8-4 Kleinburg Area Station Capacity Load

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)	97	102	111	124	134	98	98	97	96	95	95
Load Transfer to be Managed		5	14	27	37						

To manage loading at Kleinburg TS, Hydro One DX intends to transfer loads in the northern area served by Kleinburg TS to the new Northern York TS planned to be in-service by 2027.The new Northern York TS is planned to be a 230/44-27.6kV station. The TWG will review this in the next phase of the regional planning cycle.

8.1.5 Vaughan Area – Build Vaughan MTS #6 and supply from 230kV Line V43/V44 - 2027

Vaughan MTS #6 is a new identified need. Alectra plans to build a new station to provide dedicated supply to a large customer. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building. Alectra has requested that Hydro One build a short underground line tap to supply the new station from the 230kV Claireville TS x Kleinburg TS double circuit line V43/V44. The planned in-service date for the station is the end of 2027.

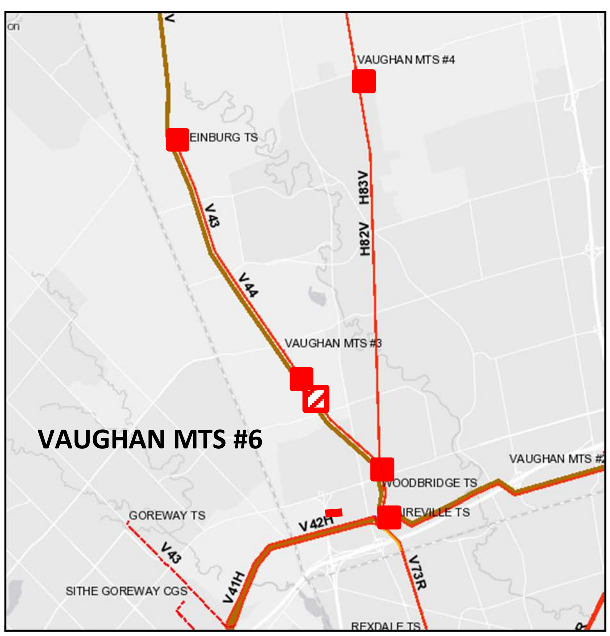


Figure-8-4 Vaughan MTS #6 Location

Table 8-5: Loading on the 230kV Claireville TS x Kleinburg TS line V43/V44

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)		62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)		102	111	124	134	98	98	97	96	95	95
Vaughan MTS #3 (28kV)		117	118	118	145	145	145	145	145	145	145
Vaughan MTS #6 (28kV)						32	31	50	52	68	72
Woodbridge TS (28kV)		87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)		85	85	86	86	86	87	87	88	90	91
Total	620	453	465	487	536	534	533	552	553	569	575

Table 8-5 shows the forecast loads connected to the line. As shown, there is adequate capacity to supply the loads over the study period.

Hydro One is currently in initial consultations with Alectra on the connection. Further details will be discussed in the next phase of the regional planning cycle.

8.1.6 Richmond Hill Area – Build Richmond Hill MTS #3 and supply from 230kV Line V71P / V75P - 2032

Richmond Hill MTS #3 is a new identified need. Alectra plans to build a new station to meet forecast loads in the 2030s. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchyard. Alectra has requested Hydro One to connect the new station to the 230kV Claireville TS x Parkway TS double circuit line V71P/V75P. The planned in-service date is summer 2032.

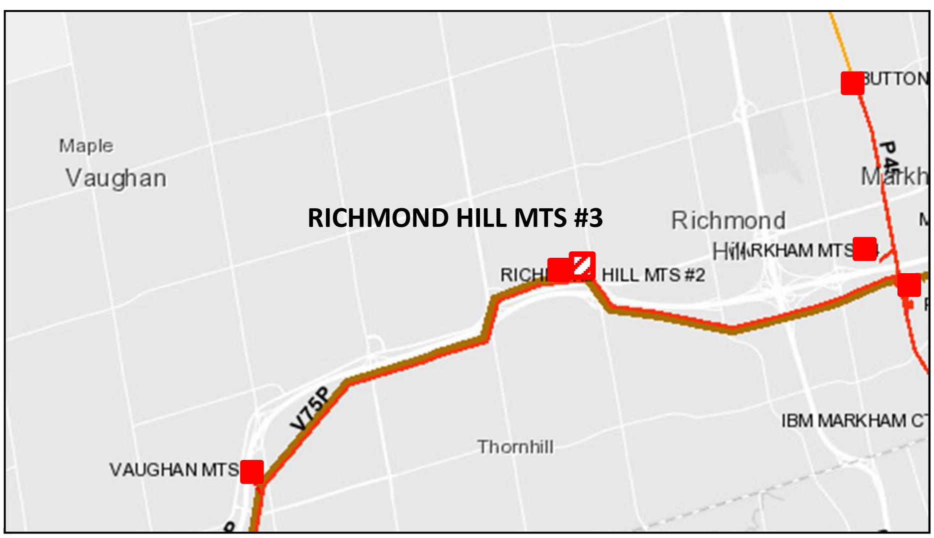


Figure-8-5 Richmond Hill MTS #3 Location

The 2020 RIP report had previously identified load security concerns with the V71P/V75P line as the connected loads exceed the 600 MW limit as per the ORTAC security criteria. However, as discussed in

Section 7.3, no action was recommended as Hydro One had installed sectionalizing switching on the line to restore load quickly in the event of a double circuit outage. The connection of the new station will further increase loading on the line. Alternatives to connect the station and address the load security need on the circuits will be developed and considered in the next phase of this RP cycle.

8.1.7 Toubner TS - 2027

Toubner TS is a new identified need. Hydro One has been requested to build a dedicated step-down transformer station for a direct industrial customer. The station will have 2 x 75/125 MVA, 230/27.6 kV transformers and a 27.6kV switchyard. The new station is in the Hwy. 7 and Hwy. 404 area and will be supplied from a tap for the 230kV line P45/P46 line tapped just north of Parkway TS. There is adequate capacity to supply the new station over the study period. The planned in-service date for the project is 2027.

Hydro One is currently in consultations with the customer to prepare connection estimates for the customer. Further details may be discussed in the current regional planning cycle.

8.1.8 Claireville x Brown Hill Transmission capacity Need- 2030

As described in Section 6.1 loading on the Claireville TS x Brown Hill TS corridor will exceed supply capacity by 2030. Alternatives to address this need will be developed and considered in the next phase of this regional planning cycle.

8.2 Long-Term Capacity Needs

With the provincial focus on decarbonization and the move away from fossil fuels, there will be a greater reliance on electricity. The GTA North region along with the rest of the province is about to embark on period of growth over the longer term driven by electrification, and large-scale development and customer connection projects are expected in several areas within the GTA North Region. The TWG will work with other stakeholders to ensure that all regional needs are met in a timely manner.

8.3 Asset Renewal Needs for Major HV Transmission Equipment – Woodbridge TS

As mentioned in Section 7.2 no asset renewal needs have been identified in the GTA North Region over the current study period other than Woodbridge TS identified in the last RIP.

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2022 44KV and 27.6kV actual peak loads were 55MW and 78 MW, respectively. Transformer T5 is currently about 51 years old and has been identified to be at its EOL.

The TWG is confirming the previous RIP identified need for the replacement of Woodbridge TS T5 transformer with similar type and size equipment as per current standard. Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area. The planned in-service date for the work is 2027.

8.4 Load Restoration and Security Needs

Load restoration need have been discussed earlier in Section 7.3, The TWG will consider these needs in the development of new plans to meet load growth and improve reliability of supply in the GTA North Region in the next phase of this regional planning cycle.

9 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

The uncertainty can stem from varying factors ranging from changes considered in potential evolution of public policy, electrification (e.g., electrification of transportation or other sectors), Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed), non-committed customer connections (both distribution and transmission), DER scenarios (e.g., battery storage), continued operation of off-contract generation.

A high demand growth forecast was developed by assuming that the forecast growth was 50% higher than the extreme summer corrected normal growth net load forecast given in Appendix C. Similarly, a low demand forecast was developed assuming that the growth was half the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Table 8-1 is summarized in Table 9-1.

Table 9-1: Impact of Sensitivity Analysis on the Identified Capacity Needs

No.	Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Toubner TS[1]	2027		
2	Vaughan MTS #6[1]	2027		
3	Northern York TS	2027	2026	2027
4	Markham MTS #5	2028	2027	2032
5	Vaughan MTS #5	2030	2030	2031
6	Richmond Hill MTS #3	2032	2029	Beyond 2032
7	Uprate circuits P45/P46[2]	2028	2028	Beyond 2032
8	Claireville X Brown Hill Corridor	2030	2027	Beyond 2032

[1]Customer requested work with defined in-service date.

[2]To be done along with the Markham MTS #5 project

Based on current equipment deliverability and construction schedules the earliest in-service dates for projects is summer 2027. The Toubner TS, Vaughan MTS #6 are customer driven projects and need to proceed. The remaining needs listed in Table 9-1will be addressed in the next phases of this planning cycle in coordination with the additional identified network capacity and load security/restoration needs and considering a longer-term forecast for the area.

10 Recommendations

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following needs and work will be proceeding as planned with all the three projects expected to be in-service by 2027.

- Woodbridge TS: Replace transformer T5
- Toubner TS: Build new station.
- Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the regional planning cycle to review and/or develop a preferred plan for the follow needs:

- Markham MTS #5: Build new station
- 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
- Northern York TS: Build new station
- Kleinburg TS 44kV: 44kV loads transfer to Northern York TS
- Vaughan MTS #5: Build new station
- Richmond Hill MTS #3: Build new station
- Claireville TS x Brown Hill TS Transmission circuit capacity need
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P.

11 References

[1]. Hydro One, "GTA North Regional Infrastructure Plan", October 22, 2020.
GTA North REGIONAL INFRASTRUCTURE PLAN (hydroone.com)

[2]. Hydro One, "Need Assessment Report, GTA North Region", March 18, 2018.
Needs Assessment Report GTA North Region (hydroone.com)

[3]. IESO, "York Region: Integrated Regional Resource Plan", February 28, 2020.
York IRRP-20200228.pdf

[4]. IESO, "York Region Scoping Assessment Outcome Report", August 28, 2018.
York-Region-Scoping Assessment-Outcome-Report-20180828.pdf

12 Appendix A. Stations in the GTA North Region

No.	Station (DESN)	Voltage (kV)	Supply Circuits
1	Armitage TS T1/T2	230/44	B88H/B89H
	Armitage TS T3/T4	230/44	B88H/B89H
2	Brown Hill TS T1/T2	230/44	B88H/B89H
3	Buttonville TS T3/T4	230/27.6	P45/P46
4	CTS	230/13.8	P21R/P22R
5	Holland TS T1/T2, T3/T4	230/44	H82V/H83V
6	Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
	Kleinburg TS T1/T2 44	230/44	V44/V43
7	Markham MTS #1 T1/T2	230/27.6	P21R/P22R
8	Markham MTS #2 T1/T2	230/27.6	C35P/C36P
9	Markham MTS #3 T1/T2	230/27.6	C35P/C36P
	Markham MTS #3 T3/T4	230/27.6	C35P/C36P
10	Markham MTS #4 T1/T2	230/27.6	P45/P46
11	Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
	Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
12	Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
	Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
13	Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
14	Vaughan MTS #3 T1/T2	230/27.6	V44/V43
15	Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V
16	Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
	Woodbridge TS T3/T5 44	230/44	V44/V43

13 Appendix B. Transmission Lines in the GTA North Region

Line	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

14 APPENDIX C: NON-COINCIDENT SUMMER PEAK NET LOAD FORECAST (2023 TO 2032)

	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Brown Hill TS (44kV)	184	94	100	118	121	125	124	125	125	126	126
Buttonville TS (28kV)	166	144	152	154	152	160	149	148	147	146	145
Holland TS (44kV)	169	166	173	176	179	169	169	169	169	169	169
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)[1]	97	102	111	124	134	98	98	97	96	95	95
Markham MTS #1 (28kV)	81	80	79	78	77	76	76	75	74	74	73
Markham MTS #2 (28kV)	101	88	98	97	96	106	94	93	93	92	91
Markham MTS #3 (28kV)	202	171	184	191	189	197	186	184	183	181	180
Markham MTS #4(28kV)	153	116	117	141	162	176	177	175	174	173	171
Markham MTS #5(28kV)	153						68	136	140	139	138
Northern York Station	170					66	80	89	99	109	118
Richmond Hill-1 MTS (28kV)	153	153	152	150	149	154	146	144	144	142	141
Richmond Hill-2 MTS (28kV)	101	95	105	104	104	111	104	104	104	105	105
Richmond Hill-3 MTS (28kV)	153										60
Toubner TS (28kV)	153					32	31	50	52	55	72
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #3 (28kV)	153	117	118	118	145	145	145	145	145	145	145
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)	153								64	132	138
Vaughan MTS #6 (28kV)	153					32	31	50	52	68	72
Woodbridge TS (28kV)	80	87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)	80	85	85	86	86	86	87	87	88	90	91
Grand Total		**2396**	**2459**	**2559**	**2652**	**2792**	**2814**	**2921**	**2997**	**3084**	**3173**

1. Kleinburg 44kV load exceeds LTR between 2023 and 2026. Excess load planned to be transferred to Northern York Region when station is built in 2027.

15 APPENDIX D: ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station (LDC owned)
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RP	Regional Planning
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

IESO response to Toronto Hydro REG Investments Plan 2025 – 2029

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan (DSP).

The OEB issued the 2023 Edition of Chapter 5 for 2024 Rate Applications on December 15, 2022 wherein section 5.2 Distribution System Plans, under "Renewable Energy Generation (REG)" states:

"A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region.

If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP."

On August 29, 2023, the IESO received a letter from Toronto Hydro-Electric System Limited (Toronto Hydro) outlining its REG Investments Plan (Plan) for comment. The IESO has reviewed Toronto Hydro's Plan and provides its comments as follows.

IESO Comments

The IESO notes that Toronto Hydro's service territory is within the Toronto region. The Toronto region is currently undergoing its third cycle of regional planning[1] and is currently at the Integrated Regional Resource Plan (IRRP) stage as of September 2023. The Toronto region completed its second cycle of regional planning with the publication of the Regional Infrastructure Plan (RIP) by Hydro One Networks Inc. in March 2020[2]. Toronto Hydro is an active, participating member of the regional planning study team.

[1] Toronto Regional Planning, IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Toronto

[2] Hydro One's Regional Infrastructure Plan, March 2020. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto%20Regional%20Infrastructure%20Plan_Mar6%202020.pdf

Toronto Hydro – Renewable Energy Generation Investments (2025-2029)

Toronto Hydro states that there are currently 305 MW of installed distributed energy resource (DER) capacity on their distribution system as of end of 2022, 116 MW of which are considered as REG. Toronto Hydro anticipates that there will be 200 MW of REG connected to their distribution system by the end of the DSP planning period in 2029. The forecasted REG and other DER connections over the Plan period (2025-2029) is being coordinated as a planning input into the regional planning process currently underway.

With respect to investments in Toronto Hydro's Plan, the IESO confirms that although it includes renewable enabling improvements (REIs) investments of an estimated $57.5 million over the Plan period for installation of bus tie reactors to alleviate short circuit constraints, improving monitoring and control to ensure safe operation of DERs (particularly during faults), and deploying energy storage systems to alleviate distribution system constraints, these investments are not a result of outcomes from the regional planning processes as outlined above. These REI investments are proposed by Toronto Hydro to improve the ability of Toronto Hydro's distribution system to accommodate REG, which is not in scope of regional planning. Therefore, the IESO has no comment on these investments.

The IESO appreciates the opportunity provided to review Toronto Hydro's Plan and looks forward to continue working together in the regional planning process.

C Performance Measurement

C1 Overview of Performance Framework

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework (RRF) categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made reflect a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the performance measures identified in each category of the custom scorecard (see Table 1 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 1: Investment Category Trigger Drivers

Performance Category	Outcome and Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

The section that follows explains Toronto Hydro's reliability performance over the 2018-2022 period in accordance with Chapter 5 Filing Requirements.[2] For details regarding Distributor Specific Reliability Targets, please refer to Exhibit 1B, Tab 3, Schedule 1 for the reliability targets proposed as part of Toronto Hydro's 2025 Custom Scorecard.

C2 Historical Reliability Performance

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in several ways:

1. All events – Including Major Event Days ("MEDs") and Loss of Supply ("LoS");
2. Excluding events relating to LoS;
3. Excluding events relating to MEDs;
4. Excluding MEDs and LoS; and
5. Excluding MEDs, LoS, and Scheduled Outages.

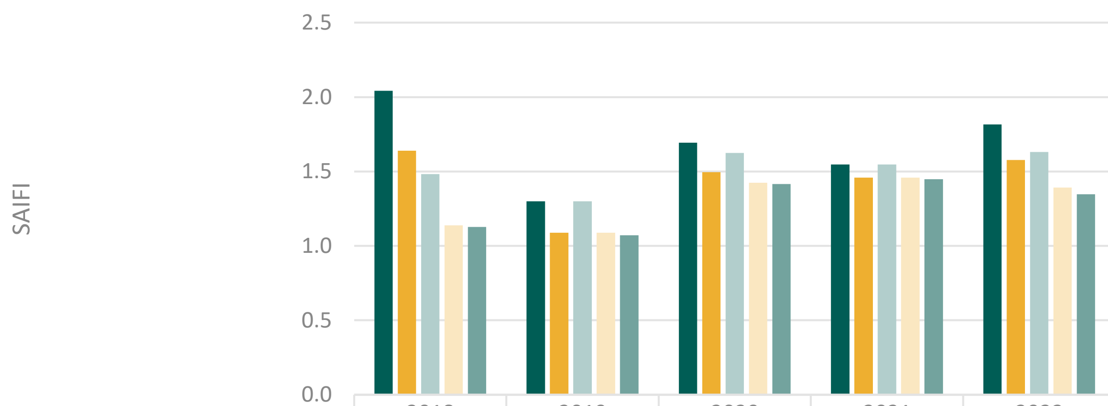
Scenarios 1, 2, 3, 4, and 5 provide SAIFI and SAIDI in the manner required by the Ontario Energy Board's prescribed Appendix 2-G, filed at Exhibit 1B, Tab 3, Schedule 2. Scenario 4 is also consistent with the Ontario Energy Board Electricity Distributor Scorecard and MD&A discussed in Exhibit 1B, Tab 3, Schedule 2. Scenario 5 provides SAIFI and SAIDI excluding MEDs, LoS, and Scheduled Outages as a more normalized reflection of total system reliability performance. Each scenario provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

C2.1 System Overview

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2018 and 2022, respectively, under each of the five scenarios. The notably higher SAIFI and SAIDI in 2018 under Scenarios 1 and 2 can be attributed to a transformer fire at Finch Transformer Station ("TS") in July (counted as both a Loss of Supply event and a MED), in addition to multiple storms that occurred in April, May, and June of that year. These occurrences were outside the utility's control and met the definition of MEDs as set out in the Ontario Energy Board's Electricity Reporting and Record Keeping Requirements

[2] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 5 (December 15, 2022) at pages 7-8.

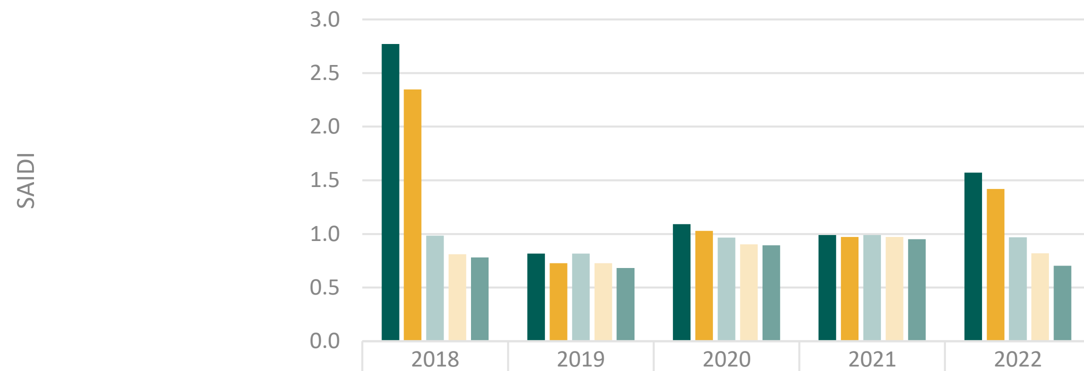
("RRR").[3] As a result, these MEDs caused the year-over-year fluctuations to be more drastic. In contrast, Scenario 3 (excluding MEDs), Scenario 4 (excluding MEDs and LoS), and Scenario 5 (excluding MEDs, LoS, and scheduled outages) illustrate more normalized SAIFI and SAIDI values with less fluctuations. Toronto Hydro considers these latter scenarios to offer greater insight into system reliability as they provide a better indication of the performance trend of the system and the impact of recent investments, and are the more commonly used indicators across the industry for benchmarking against distribution system performance. With the more normalized scenarios, there has been some worsening of performance, especially for SAIFI, over 2020-2022 and this is largely attributed to external factors, such as unknown causes or foreign interference, although defective equipment has also contributed. Additional discussion of this is provided in Sections 5-10 below.



	2018	2019	2020	2021	2022
Total SAIFI	2.04	1.30	1.69	1.55	1.82
SAIFI Excluding LOS	1.64	1.09	1.50	1.46	1.58
SAIFI Excluding MED's	1.48	1.30	1.62	1.55	1.63
SAIFI Excluding MED's and LOS	1.14	1.09	1.42	1.46	1.39
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35

Figure 1: System Level SAIFI

[3] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements ("RRR"), Section 2.1.4.2(4). (Effective March 31, 2020).



	2018	2019	2020	2021	2022
Total SAIDI	2.77	0.82	1.09	0.99	1.57
SAIDI Excluding LOS	2.35	0.73	1.03	0.97	1.42
SAIDI Excluding MED's	0.98	0.82	0.97	0.99	0.97
SAIDI Excluding MED's and LOS	0.81	0.73	0.90	0.97	0.82
SAIDI Excluding MED's, LOS and Scheduled Outages	0.78	0.68	0.90	0.95	0.70

Figure 2: System Level SAIDI

Since the early 2000s, Toronto Hydro has utilized its standalone Interruption Tracking Information System ("ITIS") to store historical reliability data. ITIS relies on manual entry of outage information, and its data is used to carry out reliability-driven analyses and to track reliability performance of the system.

Toronto Hydro upgraded its existing Outage Management System with Oracle's Network Management System ("NMS"). This new system provides Toronto Hydro with more robust data and enhanced visibility into near real-time system events.[4] As part of the multi-year NMS upgrade initiative, Toronto Hydro is implementing a new commercial solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to ITIS. OUA will streamline Toronto Hydro's interruption and reliability reporting process and seamlessly integrate with NMS.

These upgrades have and will continue to improve the data quality and accuracy of Toronto Hydro's interruption tracking and reporting. Some of these changes have resulted in higher reliability trends in 2022 when compared to historical years. Furthermore, the following changes are expected over the course of the multi-year upgrade, leading to more interruptions being captured in 2023 to 2029:

[4] For more information refer to Emergency Response at Exhibit 4, Tab 2, Schedule 5 and Control Centre Operations at Exhibit 4, Tab 2, Schedule 7.

1. Increased number of outages affecting a small number of customers.
2. Improved resolution of outage duration, down to the second.
3. Increased number of scheduled outages reported; and
4. Changes in outage structuring: currently, outages are structured manually, typically broken down by feeder. OUA will streamline this process by automatically generating outage reports based on restoration actions recorded in NMS.

C2.2 Loss of Supply

Loss of Supply ("LoS") events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. On a system level, LoS events can contribute up to 20 percent of SAIFI and 15 percent of SAIDI (based on system reliability analysis beginning in 2018), although significant variations can occur year to year. There are also considerable variations between individual LoS events, which makes it difficult to perform trend analyses and forecast future reliability performance. For instance, 21 LoS events occurred in 2019, whereas 42 LoS events occurred in 2022. Nevertheless, the fewer events in 2019 affected SAIFI and SAIDI to a greater extent due to higher impacts of individuals events in that year. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to LoS events.

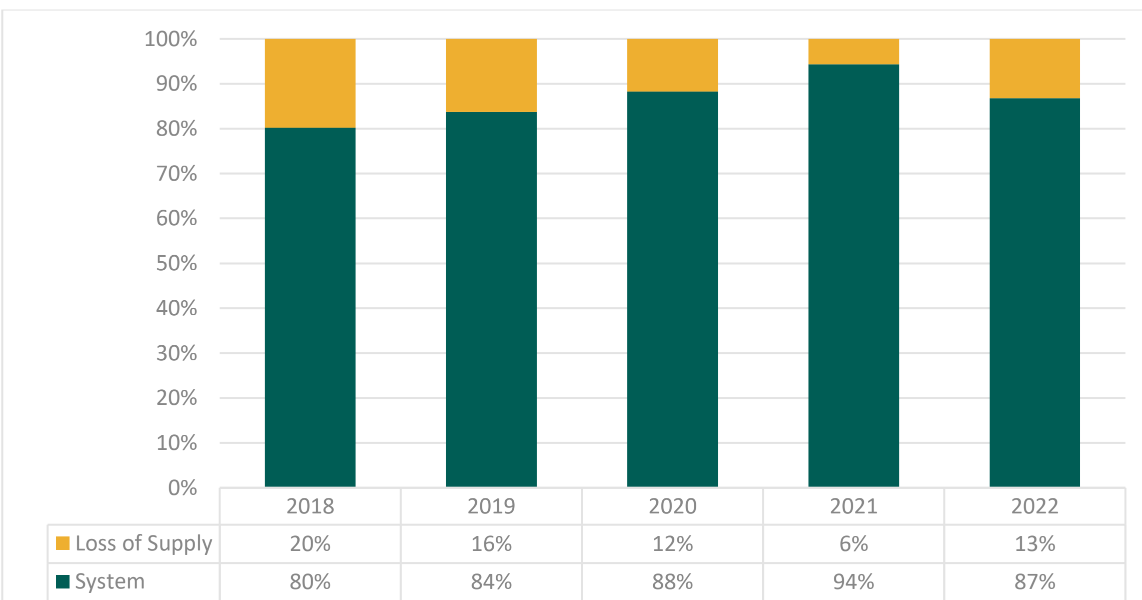
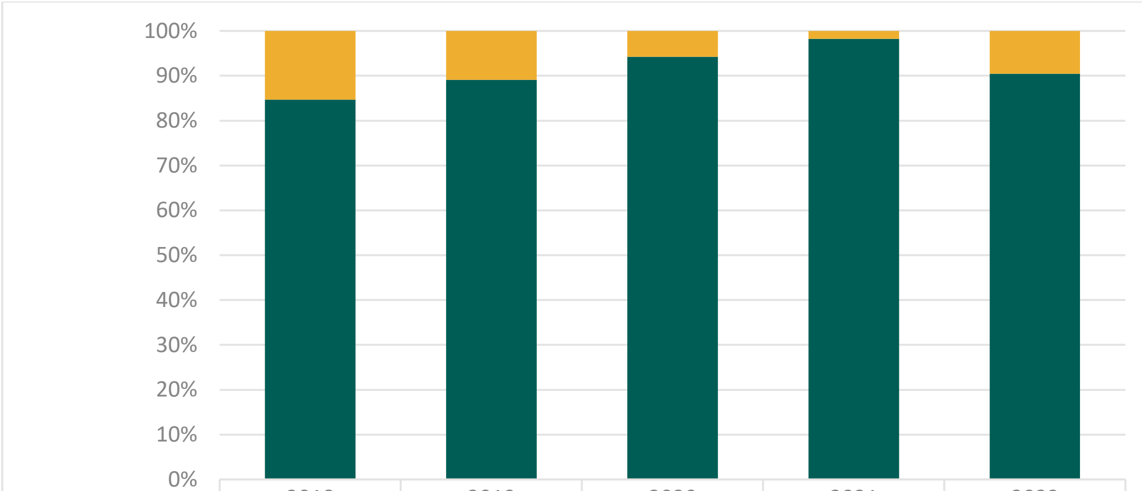


Figure 3: Loss of Supply Impact on Total SAIFI



	2018	2019	2020	2021	2022
Loss of Supply	15%	11%	6%	2%	10%
System	85%	89%	94%	98%	90%

Figure 4: Loss of Supply Impact on Total SAIDI

C2.3 Major Event Days

Major Event is defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "an event that exceeds reasonable design and/or operational limits of the electric power system",[5] where a Major Event Day ("MED") is defined as "a day in which the daily system SAIDI exceeds a Major Event Day threshold value."[5] The term Major Event is similarly defined by the Ontario Energy Board's RRR as "an event that is beyond the control of the distributor and is: unforeseeable, unpredictable, unpreventable, or unavoidable."[6] Similar to LoS events, MEDs are external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs and LoS events allows a utility to normalize its reliability data, making it possible to establish meaningful reliability performance trends and associated targets. Toronto Hydro follows the IEEE Standard 1366 Beta Method to derive the MED threshold value for the classification of MEDs.[7] Table 2 lists the MEDs experienced by Toronto Hydro since 2018 and Figure 5 shows the damage resulting from one such event.

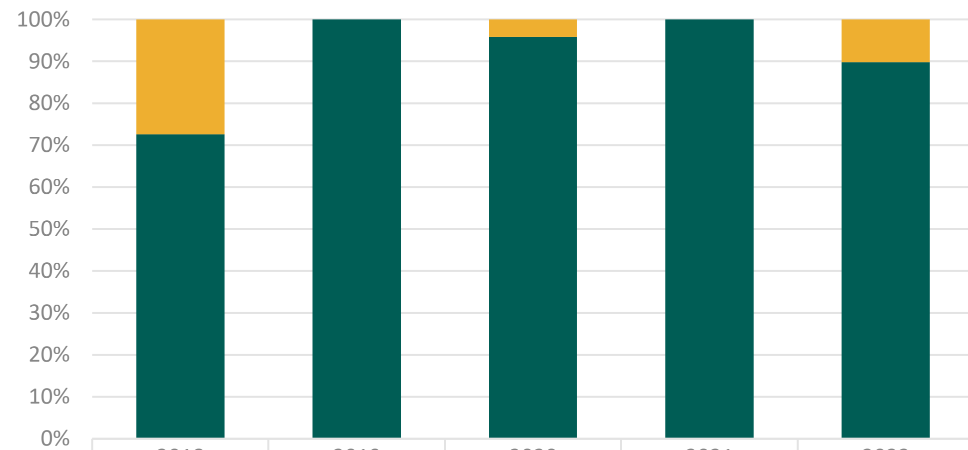
[5] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 3. Definitions.
[6] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2(4) (Effective March 8, 2023).
[7] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 4.5 Major Event Day Classification.

Table 2: Major Event Days

Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
April 4, 2018	Wind Storm	68	97,378	112,230
April 15, 2018	Freezing Rain	47	85,281	164,214
May 4, 2018	Wind Storm	98	164,261	800,390
June 13, 2018	Wind Storm	31	35,366	96,504
July 28, 2018	Loss of Supply to Finch TS	22	45,475	192,195
July 8, 2020	Wind Storm	41	54,253	97,477
May 21, 2022	Wind Storm	92	145,313	469,876

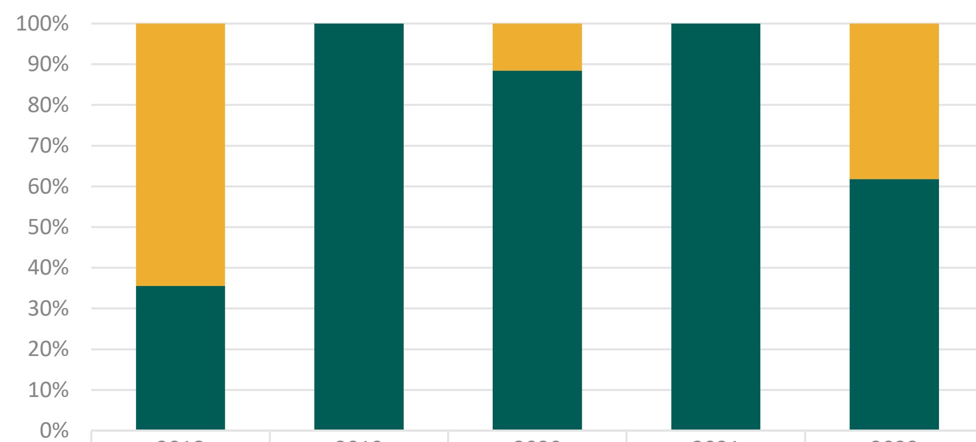
Figure 5: Post-Fire Damage at Finch Transformer Station Months Following a Major Event Day

Figures 6 and 7, below, demonstrate the SAIFI and SAIDI system impacts resulting from MEDs.



	2018	2019	2020	2021	2022
Major Events	27%	0%	4%	0%	10%
System	73%	100%	96%	100%	90%

Figure 6: Major Event Days Impact on Total SAIFI

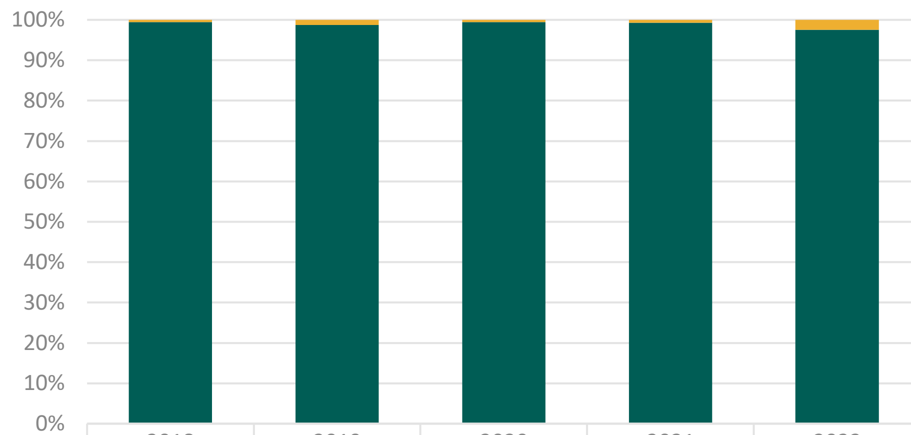


	2018	2019	2020	2021	2022
Major Events	64%	0%	12%	0%	38%
System	36%	100%	88%	100%	62%

Figure 7: Major Event Days Impact on Total SAIDI

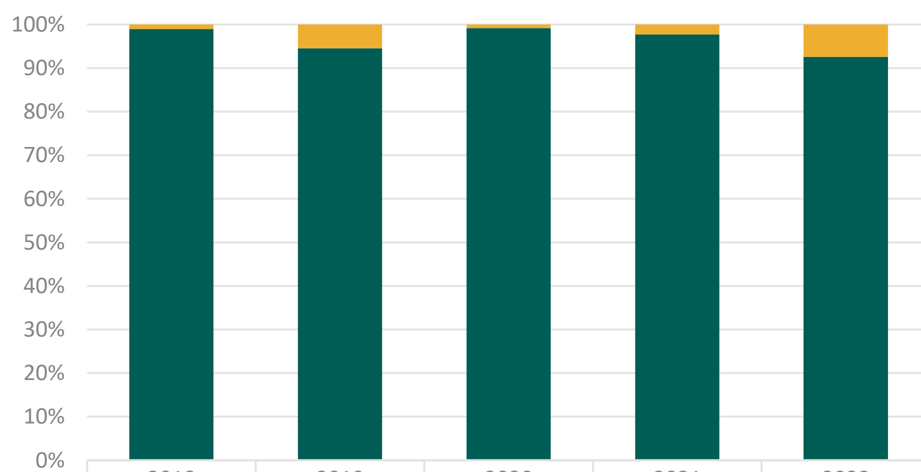
C2.4 Scheduled Outages

Scheduled outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing while in-service. These planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees and third-party contractors. Toronto Hydro provides customers advanced notification of any impeding work prior to executing the project, which gives them the opportunity to plan their activities around the repair work. Figures 8 and 9, below, demonstrate the SAIFI and SAIDI system impacts resulting from Scheduled Outages.



	2018	2019	2020	2021	2022
Scheduled Outages	1%	1%	1%	1%	2%
System	99%	99%	99%	99%	98%

Figure 8: Scheduled Outages Impact on Total SAIFI

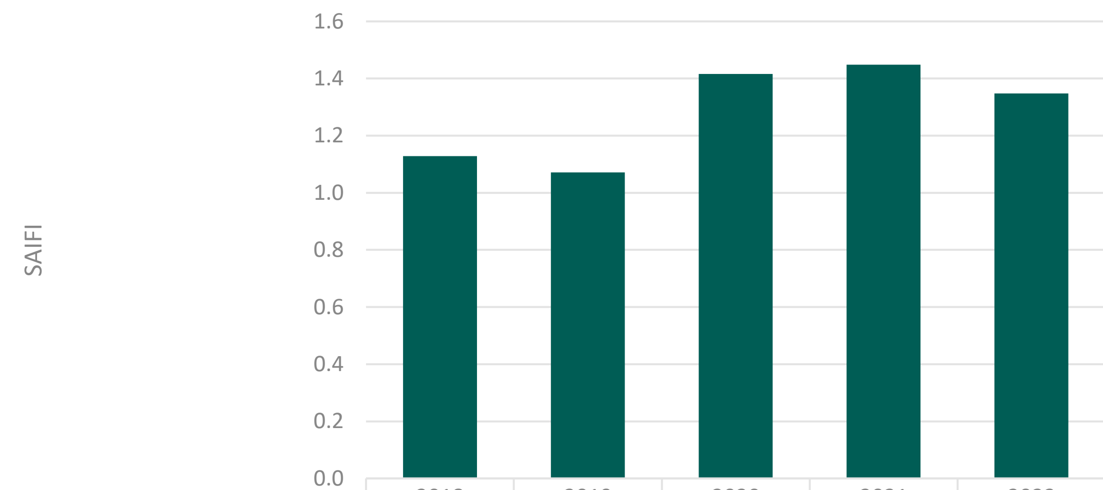


	2018	2019	2020	2021	2022
Scheduled Outages	1%	5%	1%	2%	7%
System	99%	95%	99%	98%	93%

Figure 9: Scheduled Outages Impact on Total SAIDI

C2.5 System Reliability Excluding Loss of Supply, Major Event Days, and Scheduled Outages

As noted above, MEDs and LoS events are outside the utility's control. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, scheduled outages are required to allow certain work to be completed on the distribution system such as replacing assets that are at their end of life or in deteriorated condition to prevent a future outage. The inclusion of scheduled outages in reliability analysis would not provide a true reflection of underlying distribution system performance. Figures 10 and 11, below, show the adjusted SAIFI and SAIDI (excluding LoS, MEDs, and scheduled outages).



	2018	2019	2020	2021	2022
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35

Figure 10: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages

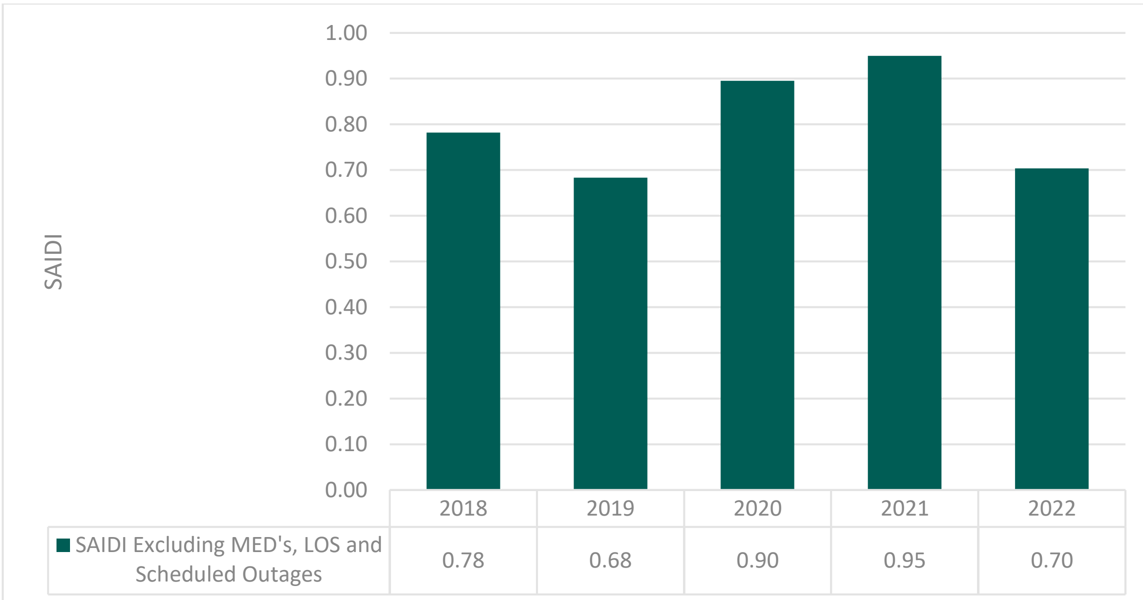


Figure 11: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages

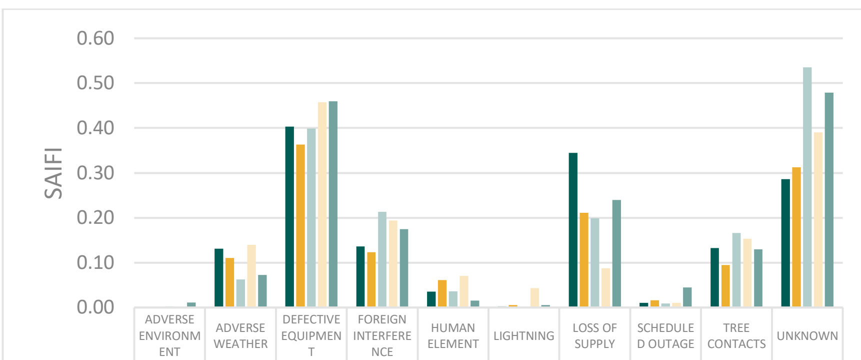
The year-over-year adjusted values show that SAIFI has increased in 2020-2022 compared to 2018-2019 levels, while SAIDI showed a temporary uptick in 2020 and 2021, but decreased back down again in 2022. This recent rise in reliability impacts was caused by a range of factors. The predominant cause for the increase in SAIFI was unknown impacts, which consist of outages that have no apparent cause. However, outages caused by foreign interference (especially animal contacts), defective equipment (including outages attributed to underground cable and cable accessories, overhead switches, overhead conductors, as well as poles and pole hardware failures), and Tree Contacts have also contributed to the overall increase in SAIFI observed during the same period, albeit to a lesser extent.

Similarly, foreign interference (including outages attributed to animal contacts, vehicles, and foreign objects) was the main contributor to the increase in SAIDI during the aforementioned period. Along with foreign interference, defective equipment (particularly underground cable and cable accessories, and overhead switch failures), unknown impacts, and tree contacts have also played a role in the observed increase in SAIDI.

The following sections provide breakdowns by cause code and more detailed discussions of trends within different cause codes and how they are impacted by Toronto Hydro's investments. More generally, Toronto Hydro's core sustainment programs[8] mainly contribute to mitigating the probability of outages due to defective equipment by proactively replacing deteriorating assets at higher risk of failure. The utility's modernization investments serve to improve reliability by reducing the customers impacted and duration of outages due to all causes – for more information on these investments, please see the System Enhancements and Network Condition Monitoring programs[9] and Toronto Hydro's Grid Modernization Road Map.[10] Some programs, such as Area Conversions,[11] contribute to reducing both the probability and length of outages by renewing aging, deteriorating, and obsolete areas of the distribution system, which are at higher risk of failure and take more time to restore power in the event of an outage.

C2.6 Cause Code Analysis

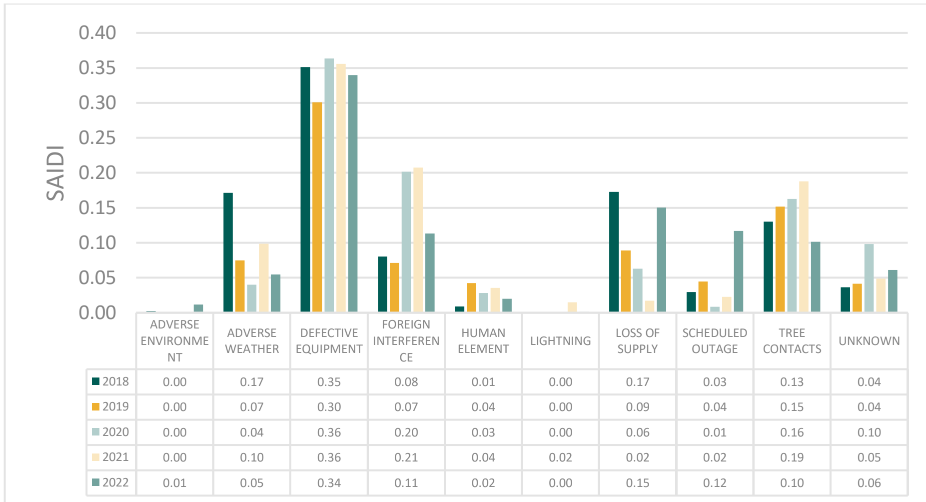
Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the Ontario Energy Board's RRR.[12] Figures 12 and 13, below, show the utility's 2018-2022 SAIFI and SAIDI performance by cause code. Table 3, below, shows the percentage contribution of each cause code to overall system SAIFI and SAIDI (excluding MEDs).



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29
2019	0.00	0.11	0.36	0.12	0.06	0.01	0.21	0.02	0.10	0.31
2020	0.00	0.06	0.40	0.21	0.04	0.00	0.20	0.01	0.17	0.54
2021	0.00	0.14	0.46	0.19	0.07	0.04	0.09	0.01	0.15	0.39
2022	0.01	0.07	0.46	0.17	0.02	0.01	0.24	0.04	0.13	0.48

Figure 12: SAIFI Cause Code Breakdown (Excluding MEDs)

[8] E.g. Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Overhead System Renewal (Exhibit 2B, Section E6.5.
[9] Exhibit 2B, Section E7.1 and E7.3.
[10] Exhibit 2B, Section D5.
[11] Exhibit 2B, Section E6.1
[12] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2.5 - Reporting Cause Codes. (Effective March 8, 2023).



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.17	0.35	0.08	0.01	0.00	0.17	0.03	0.13	0.04
2019	0.00	0.07	0.30	0.07	0.04	0.00	0.09	0.04	0.15	0.04
2020	0.00	0.04	0.36	0.20	0.03	0.00	0.06	0.01	0.16	0.10
2021	0.00	0.10	0.36	0.21	0.04	0.02	0.02	0.02	0.19	0.05
2022	0.01	0.05	0.34	0.11	0.02	0.00	0.15	0.12	0.10	0.06

Figure 13: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 3: Five-Year Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
DEFECTIVE EQUIPMENT	27.5%	36.2%
UNKNOWN	26.4%	6.1%
LOSS OF SUPPLY†	14.3%	10.4%
FOREIGN INTERFERENCE	11.1%	14.3%
TREE CONTACTS	8.9%	15.5%
ADVERSE WEATHER	6.8%	9.3%
HUMAN ELEMENT	2.9%	2.9%
SCHEDULED OUTAGE‡	1.2%	4.7%
LIGHTNING	0.8%	0.4%
ADVERSE ENVIRONMENT	0.2%	0.3%

† Excluded when evaluating Toronto Hydro's system reliability performance under Scenarios 2, 4, and 5.

‡ Excluded when evaluating Toronto Hydro's system reliability performance under Scenario 5.

On average, between 2018 and 2022, defective equipment was the main contributor to SAIFI and SAIDI, at 27.5 percent and 36.2 percent respectively. However, in 2020 and 2022, defective equipment was surpassed by unknown caused outages as the top contributor to SAIFI. As shown in Figures 12 and 13, above, the majority of improvement in 2022 SAIFI and SAIDI results relative to prior years was with respect to adverse Weather, foreign interference, and tree contacts. Toronto Hydro views the defective equipment cause code as a primary indicator of the condition of its distribution system and tracks the cause code as a measure of the effectiveness of its capital expenditure and maintenance investments. Additional analysis of certain cause codes is provided below. Tables 4-6 below also provide the number of interruptions, customer interruptions ("CI"), and customer hours interrupted ("CHI") by cause code (excluding MEDs).

Table 4: Number of Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	8	1	4	3	17
Adverse Weather	129	57	49	79	80
Defective Equipment	441	330	334	364	484
Foreign Interference	144	123	151	169	212
Human Element	19	24	23	38	31
Lightning	4	3	2	22	5
Loss of Supply	34	21	18	10	42
Scheduled Outage	143	102	137	142	907
Tree Contacts	81	48	70	104	120
Unknown/Other	135	135	224	145	233
Grand Total	1,138	844	1,012	1,076	2,131

Table 5: Number of Customer Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	988	5	2,164	249	8,786
Adverse Weather	100,462	84,803	48,318	108,474	56,744
Defective Equipment	308,064	279,474	308,633	354,985	359,936
Foreign Interference	103,812	94,716	165,199	150,885	136,878
Human Element	26,929	47,271	27,811	54,623	12,029
Lightning	1,738	4,346	273	33,840	4,151
Loss of Supply	263,344	162,433	153,684	68,259	187,464
Scheduled Outage	7,993	12,452	6,897	8,398	35,004
Tree Contacts	101,329	73,108	128,667	118,879	101,713
Unknown/Other	218,398	240,491	414,343	303,457	374,813
Grand Total	1,133,057	999,099	1,255,989	1,202,049	1,277,518

Table 6: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	1,664	9	116	420	9,353
Adverse Weather	131,115	57,672	30,890	76,673	42,846
Defective Equipment	268,452	231,449	281,347	276,297	265,983
Foreign Interference	61,487	54,799	155,980	161,211	88,595
Human Element	6,836	32,542	21,656	27,607	15,633
Lightning	346	601	630	11,684	914
Loss of Supply	131,949	68,436	48,574	13,329	117,641
Scheduled Outage	22,465	34,377	6,770	17,662	91,633
Tree Contacts	99,505	116,665	125,859	146,037	79,471
Unknown/Other	27,880	31,812	75,791	38,041	48,000
Grand Total	751,700	628,362	747,611	768,962	760,069

C2.7 Weather Impacts

The following three cause codes can generally be combined to provide a more accurate reflection of weather impacts on the system:

1. Adverse Weather,
2. Lightning, and
3. Tree Contacts.

Figures 14 and 15, below, illustrate the cumulative weather reliability impacts on the system.

Figure 14: Weather Impacts to SAIFI (Excluding MEDs)

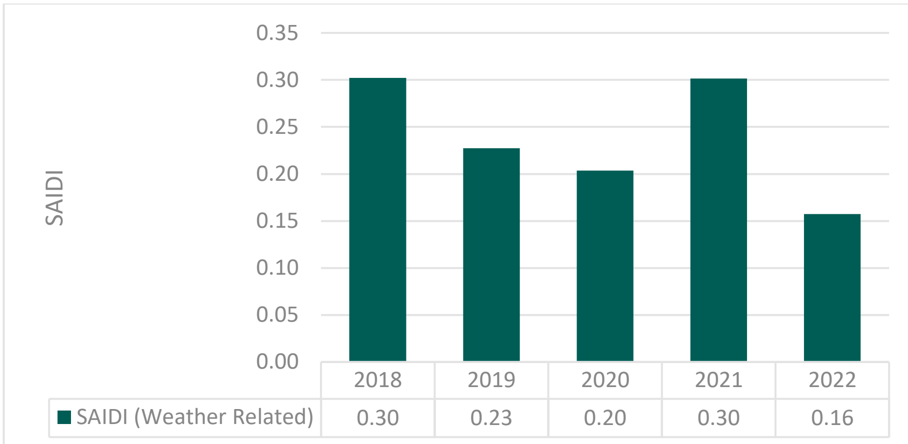
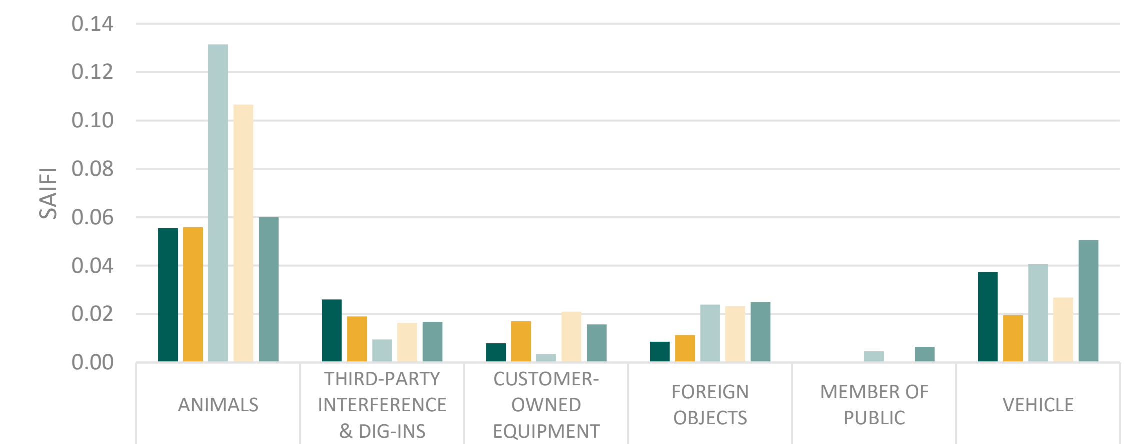


Figure 15: Weather Impacts to SAIDI (Excluding MEDs)

Weather impacts on the distribution system account for a significant portion of system SAIFI and SAIDI. For instance, in 2021 weather-related causes contributed 21.7 percent of the annual SAIFI and 30.5 percent of the annual SAIDI results (excluding MEDs). While in 2022, weather-related causes contributed 12.7 percent of the annual SAIFI and 16.2 percent of the annual SAIDI results (excluding MEDs). Figures 14 and 15, above, demonstrate that a large portion of the SAIFI and SAIDI improvements in 2022 can be attributed to relatively favorable weather conditions that year.

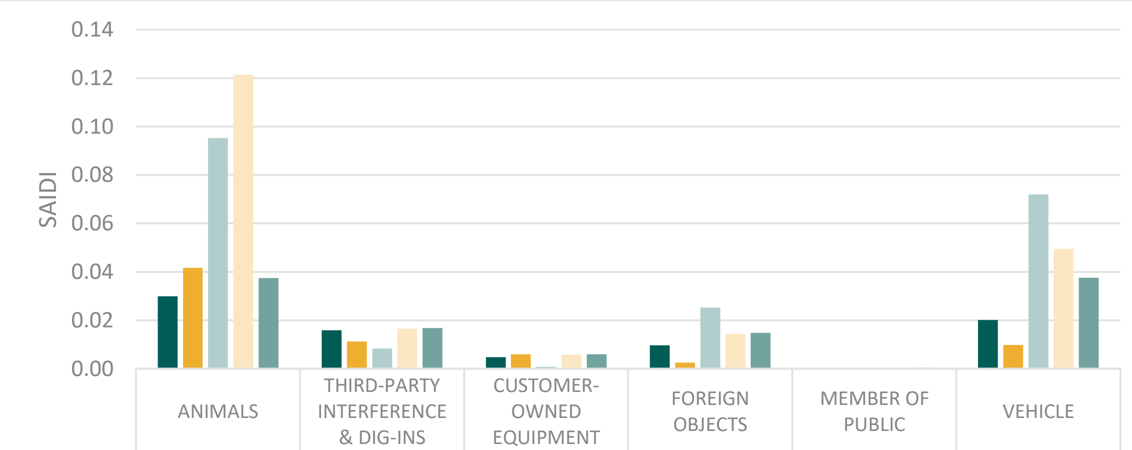
C2.8 Foreign Interference Impacts

Foreign interference consists of outages caused by animal contact, vehicles, foreign objects, third-party interference and dig-ins, customer-owned equipment, and members of the public. Although there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, yearly performance is generally volatile and largely attributable to single isolated events. Figures 16 and 17, below, show the impacts of foreign interference on Toronto Hydro's distribution system.



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.06	0.03	0.01	0.01	0.00	0.04
2019	0.06	0.02	0.02	0.01	0.00	0.02
2020	0.13	0.01	0.00	0.02	0.00	0.04
2021	0.11	0.02	0.02	0.02	0.00	0.03
2022	0.06	0.02	0.02	0.03	0.01	0.05

Figure 16: Foreign Interference – Root Cause SAIFI (Excluding MEDs)



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.03	0.02	0.00	0.01	0.00	0.02
2019	0.04	0.01	0.01	0.00	0.00	0.01
2020	0.10	0.01	0.00	0.03	0.00	0.07
2021	0.12	0.02	0.01	0.01	0.00	0.05
2022	0.04	0.02	0.01	0.01	0.00	0.04

Figure 17: Foreign Interference – Root Cause SAIDI (Excluding MEDs)

Of the six sub-categories of foreign interference shown in Figures 16 and 17, above, animal contact is one of the more “controllable” factors, in that Toronto Hydro is able to install reasonable measures to effectively mitigate this risk. More specifically, Toronto Hydro's capital programs include installing new animal guards as part of the overhead renewal program (see the Overhead System Renewal program, Exhibit 2B, Section E6.5), and conducting spot mitigation activity as part of the Worst Performing Feeder ("WPF") program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Animal guards serve to eliminate a physical point of contact with live equipment and insulate all critical components.

The category of third-party interference and dig-ins, where third parties such as other utilities or contractors have interfered with Toronto Hydro's equipment by digging into the ground, causing a fault, has shown improvement. To improve reliability and public safety, Toronto Hydro's continues to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety (refer to Exhibit 2B, Section E6.2 Underground System Renewal – Horseshoe program).

In general, the foreign interference categories mentioned above are volatile and usually beyond Toronto Hydro's control. For instance, the number of animal contacts was similar in 2020 and 2021, with 101 and 104 events respectively, and slightly increased to 116 events in 2022. However, the impact of these animal contacts on SAIFI and SAIDI varied significantly over the years, as shown in Figures 16 and 17.

C2.9 Unknown Impacts

Unknown impacts consist of outages that have no apparent cause, where power is restored by simply closing a circuit breaker or replacing a fuse. As shown by Figures 18 and 19, below, unknown impacts have increased since 2018 in terms of SAIFI and SAIDI. Toronto Hydro leverages short interval control measures for the identification and mitigation of unknown events. This includes but is not limited to performing fault localization analysis as part of an effort to identify problematic areas where past faults may have occurred in the distribution system. Targeted feeder patrols based on these fault localization results are conducted under the Corrective Maintenance program (see Exhibit 4, Tab 2, Schedule 4). The insights garnered from feeder patrols also aid in the identification of near-term corrective actions, as part of the Worst Performing Feeder program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Although Toronto Hydro makes best efforts to investigate these events, it is not always possible to pinpoint the exact cause.

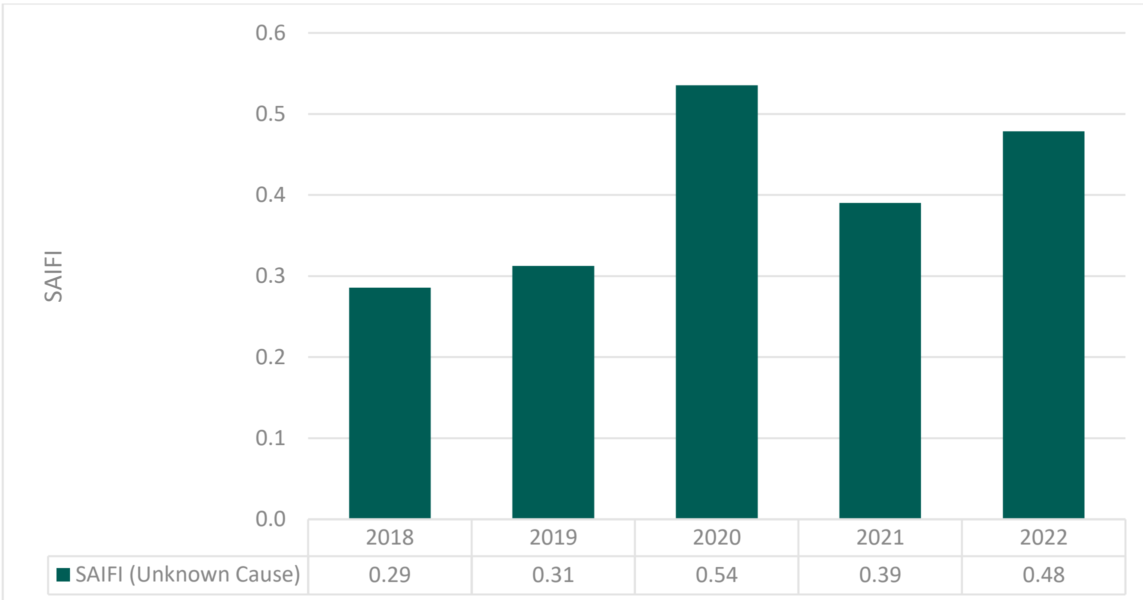


Figure 18: Unknown Impacts to SAIFI (Excluding MEDs)

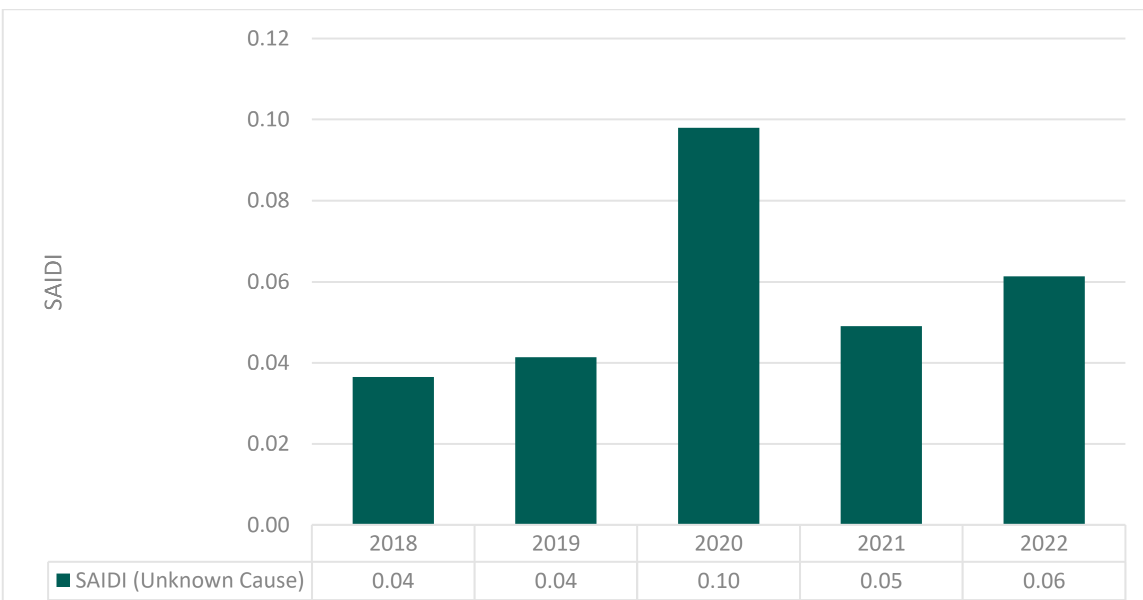
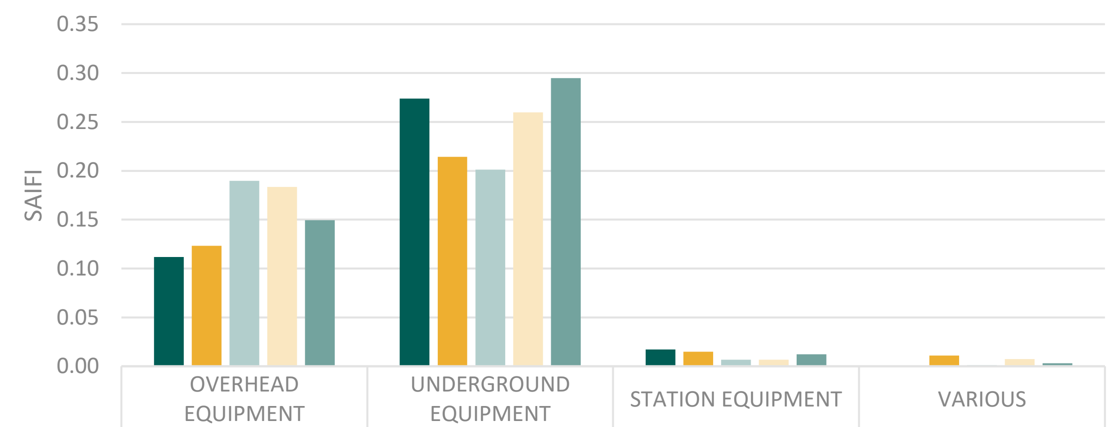


Figure 19: Unknown Impacts to SAIDI (Excluding MEDs)

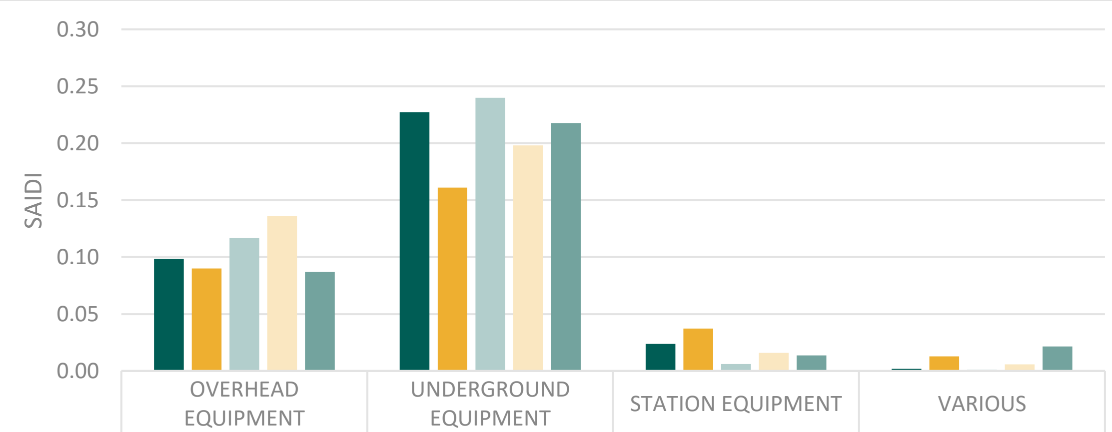
C2.10 Defective Equipment Impacts

As shown in Figures 20 and 21, below, during the 2020-2022 period the contribution of defective overhead and underground equipment to Toronto Hydro’s SAIFI has shown a rising trend. While the contribution of overhead and underground equipment to Toronto Hydro's SAIDI has shown a generally stable trend with year-to-year variation.



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.11	0.27	0.02	0.00
2019	0.12	0.21	0.01	0.01
2020	0.19	0.20	0.01	0.00
2021	0.18	0.26	0.01	0.01
2022	0.15	0.29	0.01	0.00

Figure 20: Defective Equipment SAIFI (Excluding MEDs)



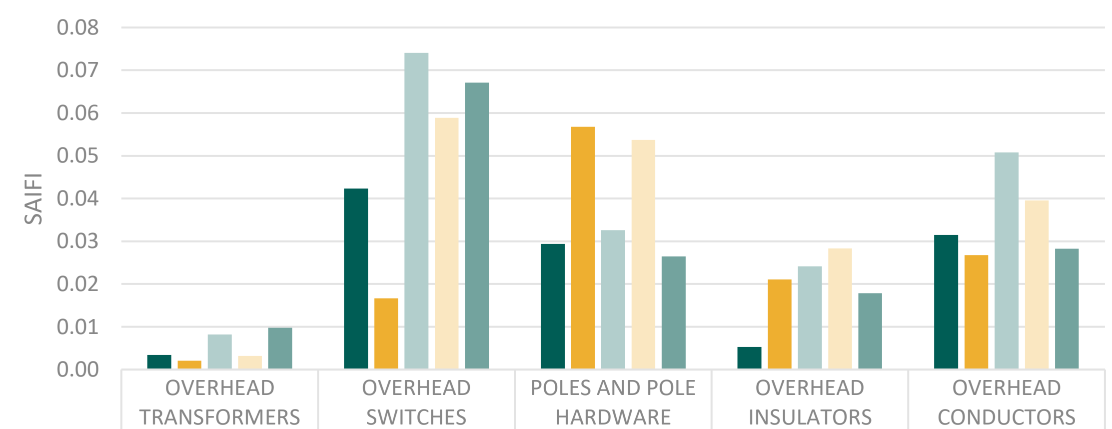
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.10	0.23	0.02	0.00
2019	0.09	0.16	0.04	0.01
2020	0.12	0.24	0.01	0.00
2021	0.14	0.20	0.02	0.01
2022	0.09	0.22	0.01	0.02

Figure 21: Defective Equipment SAIDI (Excluding MEDs)

C2.10.1 Overhead Defective Equipment

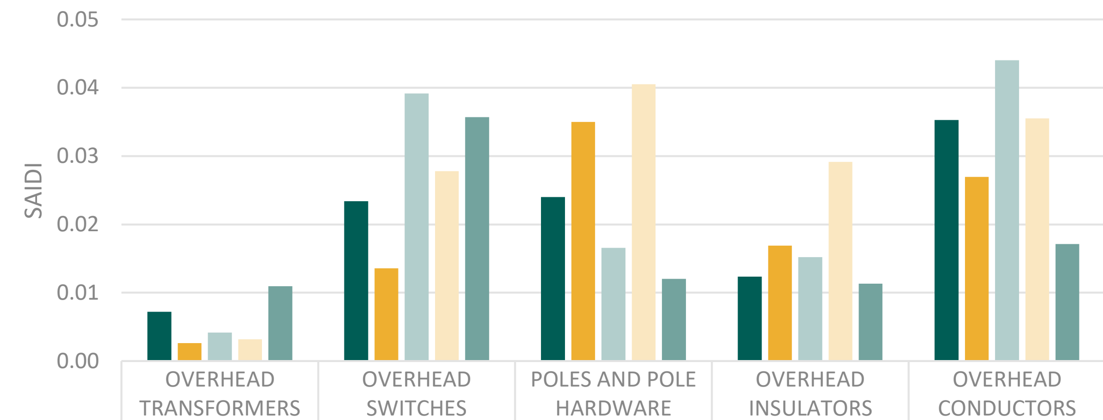
As shown by the Overhead Defective Equipment categories in Figures 22 and 23 below, the most significant SAIFI and SAIDI impacts between 2018 and 2022 are attributable to overhead switches, overhead conductors, as well as poles and pole hardware failures. This is mainly due to the magnitude of these types of failures, which often interrupt a large number of customers when they occur.

The rising SAIFI trend across the multiple sub-categories under Overhead Defective Equipment throughout the 2020-2022 period, as shown in Figure 22 below, reflects the recent focus on replacing overhead transformers at risk of containing PCBs and supports the need for continued investment in overhead system assets to maintain overall reliability, as well as to improve performance in poorly performing areas of the overhead distribution system (see Exhibit 2B, Section E6.5 Overhead System Renewal program). Other programs, such as Area Conversions (see Exhibit 2B, Section E6.1), which also renew and relocate overhead assets, have contributed to maintaining reliability on the overhead system and improving reliability in poorly performing areas. To address these trends, Toronto Hydro plans to continue investing in these important system renewal programs throughout the 2025-2029 plan period.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.04	0.03	0.01	0.03
2019	0.00	0.02	0.06	0.02	0.03
2020	0.01	0.07	0.03	0.02	0.05
2021	0.00	0.06	0.05	0.03	0.04
2022	0.01	0.07	0.03	0.02	0.03

Figure 22: Defective Equipment SAIFI – Overhead (Excluding MEDs)



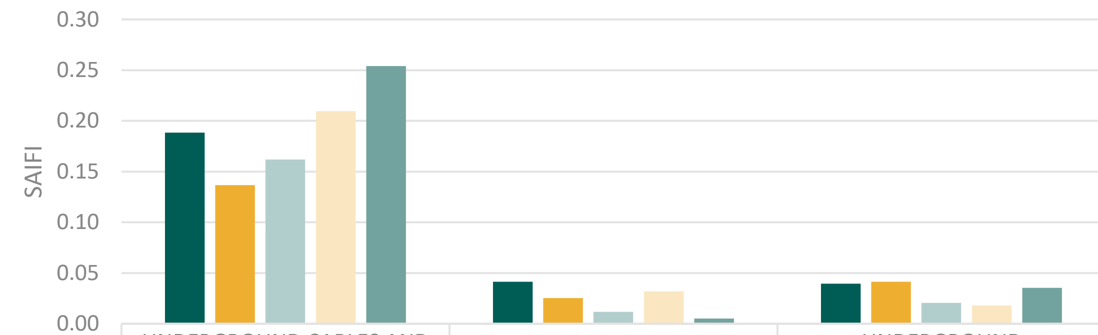
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.01	0.02	0.02	0.01	0.04
2019	0.00	0.01	0.03	0.02	0.03
2020	0.00	0.04	0.02	0.02	0.04
2021	0.00	0.03	0.04	0.03	0.04
2022	0.01	0.04	0.01	0.01	0.02

Figure 23: Defective Equipment SAIDI – Overhead (Excluding MEDs)

C2.10.2 Underground Defective Equipment

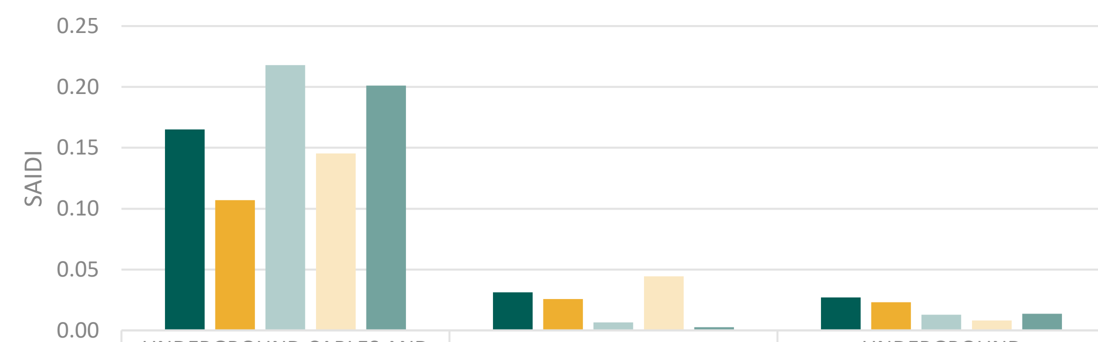
As shown by the underground defective equipment categories in Figures 24 and 25, below, underground cable and cable accessory failures dominate both the SAIFI and SAIDI indices and are the biggest equipment-related causes of interruptions in Toronto Hydro's system. Recently, Toronto Hydro has shifted focus away from rebuild projects to address urgent environmental risk associated with PCBs. However, the continued aging of direct-buried cables and of other types of cables that are reaching end of life are resulting in higher impacts for underground cable and cable accessory failures. This supports the need to refocus on investing in replacing cables that are past useful life, particularly high risk direct-buried cable, as detailed in the Underground System Renewal – Horseshoe program (see Exhibit 2B, Section E6.2), as well as performing cable diagnostic testing to improve the assessment of underground cables and cable accessories (see Exhibit 4, Tab 2, Schedule 2: Preventative and Predictive Underground Line Maintenance).

Despite the increasing trend of underground cable and cable accessory failures, the overall SAIDI trend for underground defective equipment remains relatively stable due to a decline in underground switch and transformer failures in recent years.



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.19	0.04	0.04
2019	0.14	0.03	0.04
2020	0.16	0.01	0.02
2021	0.21	0.03	0.02
2022	0.25	0.01	0.04

Figure 24: Defective Equipment SAIFI – Underground (Excluding MEDs)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.17	0.03	0.03
2019	0.11	0.03	0.02
2020	0.22	0.01	0.01
2021	0.15	0.04	0.01
2022	0.20	0.00	0.01

Figure 25: Defective Equipment SAIDI – Underground (Excluding MEDs)

D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's primary asset management process is its Asset Management System, which addresses all distribution system assets and is referenced throughout the DSP as the "AM System", "AMS" or "AM Process". The utility's processes for non-system (i.e. general plant) assets are generally aligned with the AMS, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Asset Management System ("AMS") for distribution assets;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the following sections:

- **Section D1** provides an overview of the asset management strategy and planning process for distribution assets, including the translation of corporate and stakeholder requirements into asset management objectives for the distribution system as well as for the AM system. This section also describes the asset management strategy, including continuous improvement initiatives that have been completed or commenced, with an emphasis on initiatives in the period since the OEB's December 19, 2019 decision on Toronto Hydro's 2020-2024 Custom IR application.

- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area, including expectations for the continuing evolution of these features over the forecast period and beyond.
- **Section D3** describes Toronto Hydro's asset lifecycle optimization practices that aim to balance asset cost, risk and performance.
- **Section D4** describes the changing energy landscape, how Toronto Hydro developed its *Future Energy Scenarios*, and how that work has shaped its 2025-2029 load, generation, and Non-wires Solutions related capital investment.
- **Section D5** describes Toronto Hydro's Grid Modernization Roadmap that aims to adapt the distribution system and operations to the evolving needs of the energy landscape.
- **Section D6** describes the asset management approach for facilities assets.
- **Section D7** describes Toronto Hydro's plan to achieve Net Zero for direct greenhouse gas emissions from its operations by 2040.
- **Section D8** describes the asset management approach for IT/OT assets.

In addition to the major areas listed above, the utility also utilizes a robust approach to the management of its fleet assets, described within the Fleet and Equipment capital program in Section E8.3 of this DSP.

The various asset management processes provide the architecture for long-term, short-term, and maintenance planning functions. Toronto Hydro applied these processes in developing the 2025-2029 Capital Expenditure Plan, described in Section E of the DSP, and the system maintenance plans, described in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro's Commitment to Achieving ISO 55001 Certification

As highlighted in Section D1.3 below, Toronto Hydro has an extensive track record of continuous improvement in asset management. Toronto Hydro's steady adoption and refinement of standard practices in asset management has served customers well over the last two decades. Looking ahead, the utility recognizes that the coming acceleration in decarbonization, digitization (e.g. automation), and decentralization (i.e. two-way energy flows) within the energy economy will result in much greater asset management complexity and a more urgent need for adaptive flexibility within the utility's management systems. The utility believes that success in this more complex environment will depend in large part on having a strong management foundation in the form of a rigorous and comprehensive AMS that consistently tracks toward industry best practices.

With this context in mind, Toronto Hydro is committing to aligning its AMS to the ISO 55001 standard for asset management, with the goal of achieving certification within the 2025-2029 rate period. ISO 55001 was developed by the International Organization for Standardization and is the most recognized standard for asset management globally. It provides terminology, requirements and guidance for establishing, implementing, maintaining and improving an effective asset management system, and represents a global consensus on asset management and how it can increase the value generated by organizations like Toronto Hydro.

Fundamental to the ISO 55001 framework are the concepts of strategic alignment, risk-based decision-making and continuous improvement. By pursuing certification, Toronto Hydro is volunteering to being held accountable through independent audits for the continuous improvement of its AMS and the maturation of its risk-based decision-making frameworks. The utility believes that the effort of pursuing certification will provide the additional rigor and discipline required to deliver greater value and performance, including greater cost-efficiency, as customer and stakeholder needs rapidly evolve and operating challenges become more intense (e.g. climate risk).

D1.1 Asset Management Objectives and Outcomes

Toronto Hydro's asset management objectives are to a large extent driven by relevant legislative and regulatory obligations and guidance such as the OEB's Distribution System Code ("DSC") and the *Electricity Act, 1998*, including:

- Following good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis;[1]
- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand";[2] and

[1] Ontario Energy Board, Distribution System Code, Section 4.4.1

[2] Electricity Act, 1998, Section 1.

- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[3]

Additionally, Toronto Hydro aligns its AMS with other applicable legislative and regulatory requirements and principles, including the *Ontario Energy Board Act*, *1998*,[4] Toronto Hydro's Distribution Licence, the Standard Supply Service Code[5], and relevant City of Toronto by-laws.

Beyond its mandated service and compliance obligations, the broader objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

Toronto Hydro's AM strategy is in line with corporate strategy and stakeholder needs and preferences. AM objectives are set in order to achieve the AM strategy. Toronto Hydro has aligned its AMS with the utility's strategy for the regulated business, as described in Exhibits 1B, Tab 1 and Exhibit 2B Section E2 of the DSP.

Toronto Hydro's corporate strategy and associated business planning processes, including the AMS, are guided by a set of principles that align with the utility's five corporate pillars. As represented in Figure 1 below, the utility maintains a constant focus on these five pillars – Customer, Environment, Operations, People, and Financial – in a balanced way that promotes customer value and a sustainable business. These principles are an essential element in the determination and prioritization of outcomes.

[3] Ibid.

[4] SO 1998, Ch 15, Sched. B

[5] Ontario Energy Board, Standard Supply Service Code (SSSC), "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/standard-supply-service-code-sssc#:~:text=Sets%20out%20the%20rules%20that,connected%20to%20their%20distribution%20system.

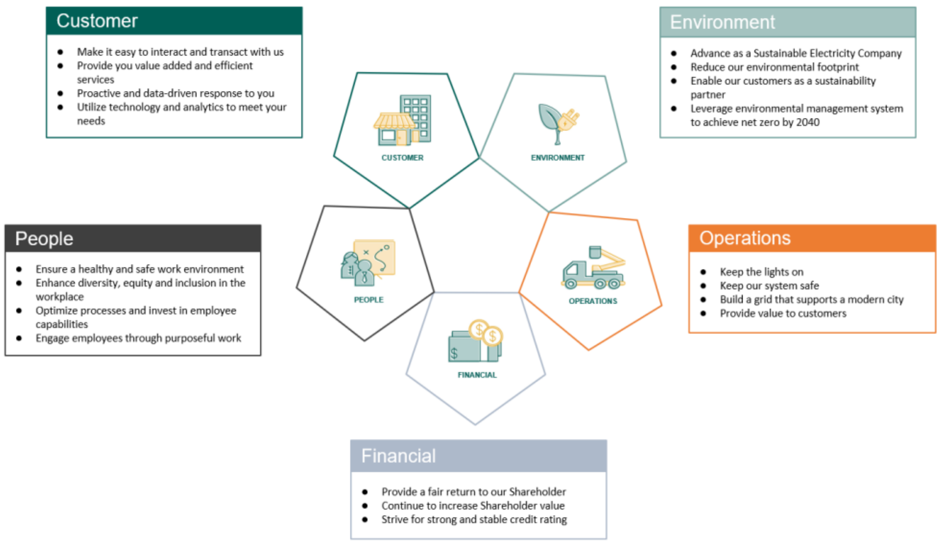


Figure 1: Toronto Hydro's Corporate Pillars

D1.2 Asset Management Process Overview

This section outlines the major elements of the AMS for distribution system assets, their inter-relationships, and the key inputs and outputs between each element.

The corporate direction outlined in the previous section determines the overall direction for decision-making throughout the AMS. At the same time, the information and performance results generated by the AMS inform the continuous refinement of corporate objectives, in balance with other considerations such as asset needs based on the current and future state of the system, customer engagement and benchmarking results.

Figure 2, below, illustrates the major planning and execution process elements of AMS, consisting of five main components:

- Investment Planning and Portfolio Reporting ("IPPR") Process;
- Scope and Project Development;
- Program Management and Execution;
- Performance Measurement; and
- Standards and Practice Review.

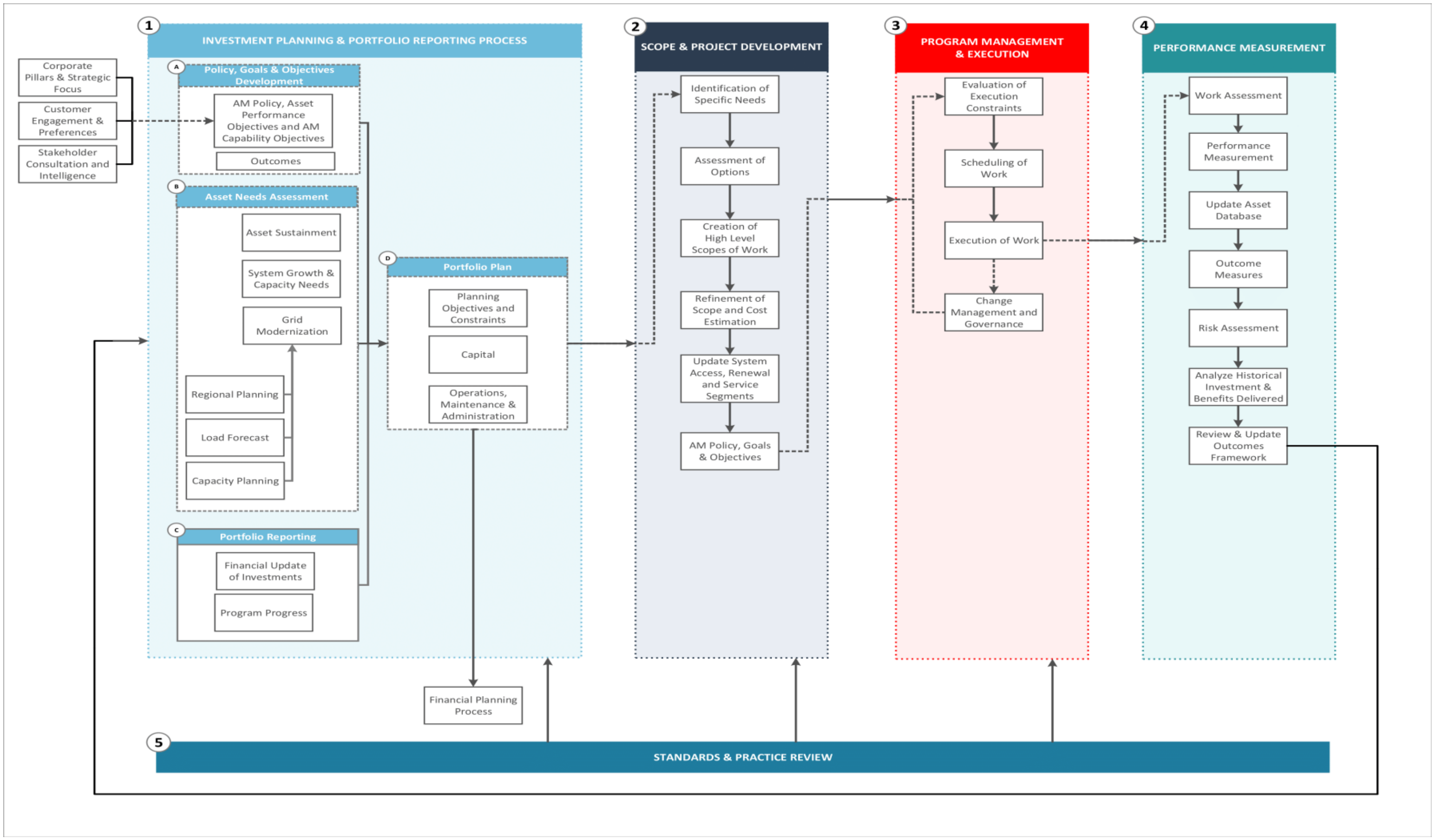


Figure 2: Asset Management Process Overview

The following sections outline each main component of the AM Process.

D1.2.1 Investment Planning and Portfolio Reporting ("IPPR") Process

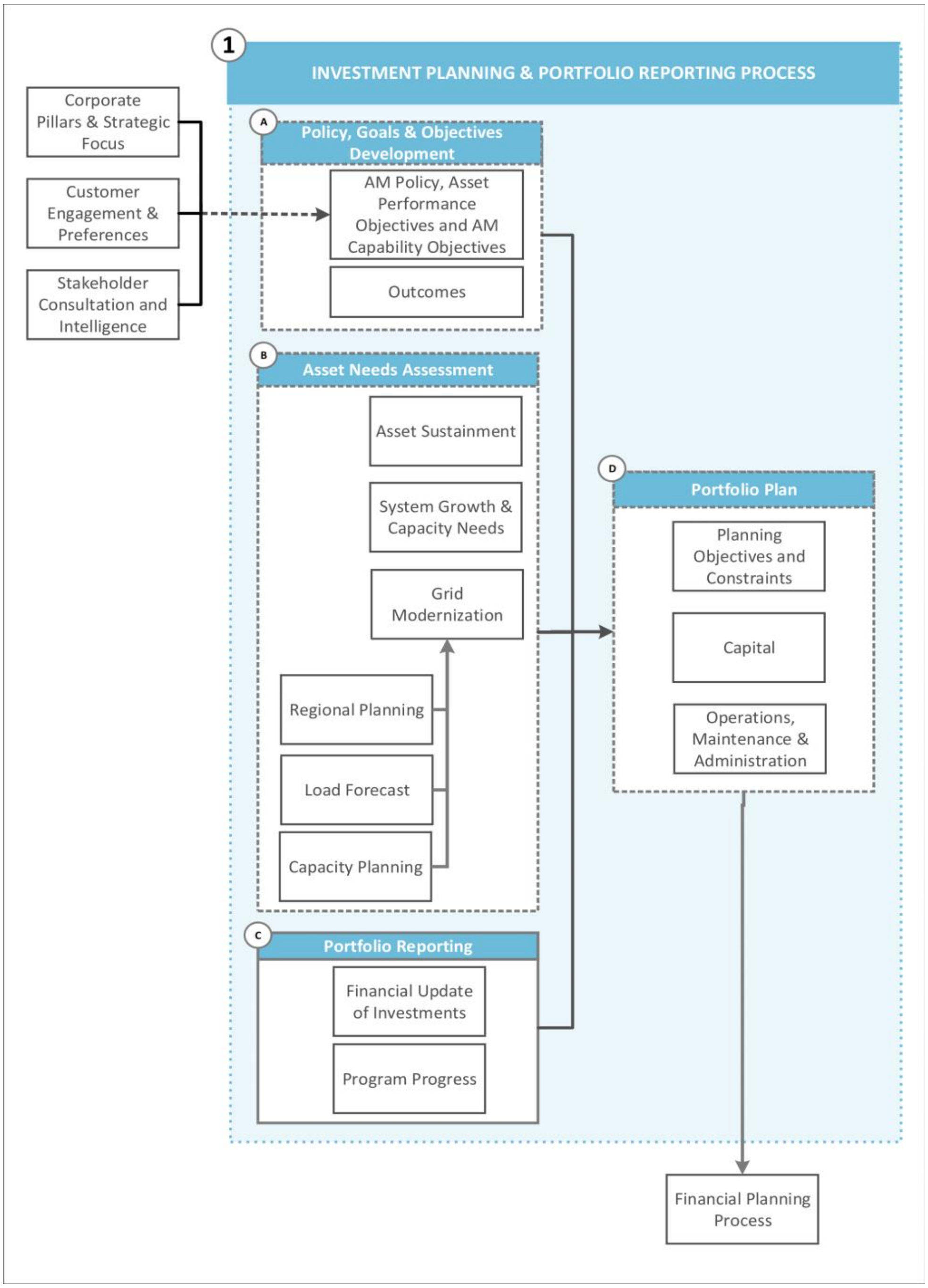


Figure 3: IPPR Process

The IPPR process is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. The IPPR process aims to report on the current state of assets, forecast future states and associated risks, and assemble holistic investment plans. This integrated annual planning process involves:

- the analysis of current systematic needs and historic trends;
- the development of short-term and long-term plans – program forecasts, associated work volumes and performance objectives; and
- the optimization of different strategies by balancing financial constraints, risks, and outcomes.

It is composed of four sets of activities:

- **Policy, Goals and Objectives Development:** The IPPR process is guided by Toronto Hydro's asset management policy, goals and objectives. The utility periodically reviews and updates these elements to ensure continuous alignment of asset management decision-making with corporate strategy and customer and stakeholder needs and preferences. These activities are discussed in detail in section D1.2.1.1 below.
- **Asset Needs Assessment:** To determine the types and level of asset investment needed, Toronto Hydro tracks and analyzes the current state of its assets, their performance relative to a wide variety of risk indicators (e.g. environmental, reliability, and safety indicators), their ability to serve evolving demands from customers and external parties (e.g. bus-level load forecasts and evolving power quality needs), and grid enhancement and modernization roadmap. These activities are discussed in detail in section D1.2.1.2 below.
- **Portfolio Reporting:** Toronto Hydro monitors and assesses the progress of its system capital and maintenance programs against annual and longer-term budget, execution, and performance objectives. This helps ensure the utility is cost-effectively executing the DSP while making prudent adjustments in light of new information. These activities are discussed further in section D1.2.1.3 below.
- **Portfolio Planning**: Toronto Hydro uses the outputs of the above three activities to develop capital and maintenance investment plans for its portfolio of programs. These plans are the result of the utility's asset management goals and outcomes as applied to a combination of the current needs of the system and the current status of ongoing investment activities and accomplishments. Key aspects of the portfolio planning activity include the consideration of alternative investment strategies and the development of both short- and longer-term

expenditure plans for each capital program. These activities are described in detail in section D1.2.1.4 below.

Toronto Hydro executes all of the above activities annually, which ensures alignment between (i) the projects selected for execution within an annual capital plan and (ii) the utility's overall five-year expenditure plan and outcome objectives. The four major activities of the IPPR process are explained in further detail in the following sections.

D1.2.1.1 AM Policy, Asset Performance Objectives and AM Capability Objectives

Senior management direction for the AMS is provided through the Asset Management Policy and a set of strategic Asset Performance Objectives and AM Capability Objectives. The utility periodically reviews and, if necessary, adjusts these components of the AMS to ensure alignment with corporate strategy and evolving customer and stakeholder needs.

In 2022, as part of the utility's ongoing effort to align with the ISO 55001 standard for asset management, Toronto Hydro issued an updated corporate Asset Management Policy applicable to its distribution assets. This policy was developed in accordance with industry best practices and reflects Toronto Hydro's corporate strategy and organizational intent for managing its assets.

The substantive component of the Asset Management Policy is the following policy statement:

> *"Toronto Hydro's asset management policy is to ensure that it effectively manages its electricity distribution assets, across the complete asset lifecycle, in a safe, cost-effective, and sustainable manner, and that the management of those assets meets the needs of its customers and stakeholders, and provides a fair return to its shareholder. Toronto Hydro shall comply with all legal, regulatory and environmental requirements placed upon the organization and will prioritize the safety of its employees and the public.*
>
> *This Asset Management Policy shall be achieved through the management and continuous improvement of an efficient, coordinated, systematic, and embedded Asset Management System that:*
>
> - *develops and implements a Strategic Asset Management Plan;*
> - *balances costs, risks, opportunities and performance by applying a holistic approach to decision-making while:*

  - *optimizing the distribution system's reliability performance in accordance with customer needs and preferences;*
  - *enabling growth, fostering electrification, and accommodating evolving consumer and stakeholder needs; and striving for zero public and employee safety incidents.*
- *aligns with Toronto Hydro's corporate strategy as well as its safety and environmental management systems;*
- *collects and analyzes asset information to enable informed and holistic decision-making; and*
- *ensures the availability of the required resources to develop and implement Asset Management strategies and plans.*

All employees and contractors shall comply with this policy and contribute towards the continuous improvement of the Asset Management System."

Following the issuance of this policy in 2022, Toronto Hydro introduced a training module to foster company-wide awareness of the Asset Management Policy, the Asset Management System, and the benefits of continuous improvement in Asset Management. The utility also introduced formal Asset Management training programs to accelerate the onboarding and development of new employees, as well as a more intensive certification program for employees in key roles, to augment their understanding of the AMS, enable them to be stewards of the system, and foster a culture of continuous improvement.

As noted in the policy statement, the development of a Strategic Asset Management Plan ("SAMP") is an essential component of the AMS. Currently, the 2025-2029 Distribution System Plan (Exhibit 2B) serves as the utility's SAMP document. As Toronto Hydro continues its journey toward ISO 55001 certification, the intention is to develop a stand-alone SAMP document which will be updated more frequently and will form the basis for future DSPs.

Toronto Hydro's asset management strategy is encapsulated by two complimentary sets of objectives:

i. **Asset Performance Objectives**, which articulate Toronto Hydro's major customer- and stakeholder-focused performance objectives for its assets, i.e. "what" needs to be achieved with the assets; and

ii. **AM Capability Objectives**, which focus on the organization's capability to manage its assets, i.e. "how" the organization can manage its assets to achieve the performance objectives.

Toronto Hydro's Asset Performance Objectives for 2025-2029 are summarized in Tables 1 to 3 below. These objectives are aligned with the overall investment plan objectives and the utility's performance incentive framework and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP.

Table 1: Asset Performance Objectives and Key Measures for Growth & City Electrification

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Accommodate relocations for committed third-party developments, including priority transit projects	1. New Services Connected on Time 2. Customer Satisfaction
Operational Effectiveness - Reliability	• Expand stations capacity to alleviate future load constraints, with consideration for increased electric vehicle uptake, decarbonization drivers, and other growth factors (digitalization and redevelopment) • Install control and monitoring capabilities for all generators > 50kW	1. System Capacity[6]
Public Policy Responsiveness	• Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency (i.e. flexibility services) • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections, including by supporting customers and third-parties to more easily identify optimal locations for DER projects	1. System Capacity 2. Restricted Feeders (DERs) 3. Distributed Generation Facilities Connected on Time

[6] System Capacity includes bus loading, heat restricted feeders, feeder position availability, etc.

1 **Table 2: Asset Performance Objectives and Key Measures for Sustainment & Stewardship**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Operational Effectiveness - Safety	• Adhere to previous commitments for safety compliance activities (e.g. complete Box Conversion by 2026)	1. Total Recordable Injury Frequency 2. Serious Electrical Incident Index 3. Box Framed Poles Remaining on the System 4. Non-Energy Mitigating Cable Chamber Lids in High Risk Locations
Operational Effectiveness - Reliability	• Maintain recent historical system reliability, which includes: ○ leveraging risk-based decision-making to ensure System Renewal investments are sufficient to maintain recent historical reliability for outages caused by Defective Equipment; and ○ leveraging the Worst Performing Feeder program and other intervention tactics to improve reliability for customers experiencing service that is much worse than average • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools	1. Defective Equipment Outages (SAIDI, SAIFI) 2. Worst Performing Feeders (e.g. FESI) 3. Asset Health 4. % Assets Past Useful Life 5. Rear Lot Customers on System 6. Direct-buried Cable on System (km) 7. Network Modernization (% of submersible units)
Public Policy Responsiveness	• Adhere to previous commitments for environmental compliance activities (e.g. removal of at-risk PCBs by 2025)	1. PCB-contaminated Oil Spills 2. Lead Cable Remaining on System (km)
Financial Performance	• Ensure investment pacing contributes to stable long-term investment profiles for all assets (2030+)	1. Asset Health 2. % Assets Past Useful Life 3. Network Modernization (% of submersible units)

1 **Table 3: Asset Performance Objectives and Key Measures for Modernization**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency) • Leverage technology to improve customer experience (e.g. customer tools)	1. Customer Satisfaction 2. Bill Accuracy 3. Estimated Time of Restoration (ETOR) 4. Customer Escalations Resolution
Operational Effectiveness - Reliability	• Improve system reliability through greater system controllability (e.g. SCADA-enabled sectionalizing points) and enhanced fault management technologies, including advanced metering infrastructure (AMI 2.0) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown • Leverage technology to improve customer experience (e.g. reliability, power quality) • Enhance system observability, enabling better asset management and operational decision making and expanding the foundation for advanced distribution automation	1. Grid Automation Readiness 2. System Reliability (e.g. SAIFI, SAIDI) 3. Load Secured During Contingency Event (e.g. Loss of Supply)
Public Policy Responsiveness	• Leverage technology to improve customer experience (e.g. DER integration)	1. Restricted Feeders (DERs) 2. Distributed Generation Facilities Connected on Time
Financial Performance	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency)	1. Grid Automation Readiness 2. System Capacity (Non-Wires) 3. Efficiency Achievements

As part of its effort to achieve ISO 55001 certification, Toronto Hydro is developing a detailed asset management roadmap which will lay out a series of longer-term AM Capability Objectives that the utility intends to pursue in the years ahead. Many of these capability building efforts fall into one of three strategic categories, which align with the utility's overall modernization and performance strategy for 2025-2029 and beyond:

1. **Enhancements to Risk-based Asset Management and Investment Portfolio Optimization Tools:** Toronto Hydro is currently executing a multi-year project to implement an industry-leading value framework within its new Engineering Asset Investment Planning ("EAIP") platform, Copperleaf C55. The EAIP platform is a powerful decision-support tool that facilitates consistent and objective value-based optimizations of the utility's substantial portfolio of capital projects.

   At the heart of this tool is a custom value framework that Toronto Hydro is currently developing which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the utility's Condition Based Risk Management ("CBRM") framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. As discussed in D1.3.2.1 and in Section D3, Toronto Hydro is committed to continuously reviewing and enhancing its CBRM to ensure alignment with the observed reality of its assets in the field. The utility is also committed to researching and developing more sophisticated risk-based decision frameworks for assets that do not currently have condition-based models, including underground cable systems, in the 2025-2029 period.

   As for its EAIP tool, Toronto Hydro is currently on track to begin leveraging its optimization capabilities for the majority of its investment program by the beginning of the 2025-2029 period. Following EAIP implementation, Toronto Hydro plans to extend the use of its value framework upstream of the EAIP tool as part of a predictive/prescriptive analytics solution which will assist investment planners in identifying project candidates with the greatest potential value to customers.

2. **Asset Information Strategy and Governance:** As part of its journey toward ISO 55001 certification, the utility is in the process of developing an Asset Information Strategy that

outlines current and future asset information needs. This will be accompanied by a system agnostic Asset Information Standard document, which will help improve consistency in how mission-critical asset and customer information is classified, stored, and assessed for quality. Toronto Hydro also intends to develop a more comprehensive and rigorous data and analytics governance framework to support the development and adoption of decision-making tools and insights that can drive greater efficiency and performance. Toronto Hydro believes that greater use of data and analytics will be a significant driver of value in the 2025-2029 period and beyond. Furthermore, highly accurate and accessible asset and system data will be essential to the successful implementation of next-generation operational forecasting and automation tools such as the Advanced Distribution Management System and Distributed Energy Resource Management System. As part of the Grid Modernization Roadmap, the Asset Analytics & Decision-making portfolio covers Toronto Hydro's plans to fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. One of the domains of this portfolio involves integration of relevant enterprise systems into a fully harmonized asset data registry for asset planning. Some of the relevant enterprise systems are: the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. The Asset Analytics & Decision-making portfolio is further described in Exhibit 2B, Section D5.

3. **Developing Enhanced Asset Analytics:** Toronto Hydro is currently ramping up its efforts to develop a more robust asset data analytics function. This effort involves three major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, (ii) researching, evaluating, and procuring advanced analytics solutions to meet specific asset management and operational needs and (iii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications. The utility has a rich trove of data which can be leveraged to create new insights to support better decision-making, and observability enhancing technologies such as AMI 2.0 promise to provide a step increase in the amount of data available to planners and system operators in the years to come. In the last several years, Toronto Hydro has made headway with respect to building out its analytics applications, for example by investing in the province's first long-term, distribution-level scenarios model for the energy transition, and developing

several pilot applications (not yet in production), including a homegrown electric vehicle detection model prototype, and a machine learning concept for predicting the cause of "Unknown" outages. Toronto Hydro plans to make accelerated investments in its asset analytics and machine learning capabilities over the next six years, including enhancing its use of simulation platforms to develop more robust insights into emerging challenges such as the capacity to host DERs on its system. As part of the development and evolution of Toronto Hydro's Asset Analytics & Decision-Making modernization strategy, the utility plans to enable predictive and prescriptive analytics in the utility's business processes through the use of advanced tools, such as artificial intelligence and machine learning (further described in Exhibit 2B, Section D5).

In addition to these three major categories of AM Capability Objectives, Toronto Hydro plans to pursue a variety of other enhancements to its AMS and AM capabilities, including planning process improvements, enhanced forecasting tools to support continuous improvement in areas such as supply chain management and construction labour balancing, and digital process automation to improve the efficiency and consistency of many elements of the AMS.

D1.2.1.2 Asset Needs Assessment

Toronto Hydro completes a needs assessment of its distribution system to determine the type of investments required. This includes determining the current state of assets, identifying system needs and challenges, and incorporating load forecasts and regional planning results. Further details on these focus areas and how they are used in developing the investment plans can be found in Section D3.2.

Toronto Hydro regularly performs a foundational analysis to understand the current state of the distribution system in terms of asset properties and quantities, asset performance risk (e.g. age, condition, and obsolescence), historical reliability, and asset utilization (e.g. capacity to connect customers and serve peak load). There are three areas Toronto Hydro focusses on to determine current and future asset needs: Asset Sustainment, System Growth and Capacity Needs, and Grid Modernization.

1. <u>Asset Sustainment</u>

Toronto Hydro aims to ensure stable long-term performance of its assets, maintain system reliability, and minimize asset failure risk. When an asset is assessed to be in poor condition, it is considered for repair, upgrade or replacement under current standards (including regulatory and Toronto Hydro standards).

The typical planning process includes a review of:

- Condition Based Risk Framework;
- Assets Past Useful Life; and
- Potential Consequences of Failure.

Toronto Hydro's Asset Condition Assessment ("ACA") is the utility's Condition Based Risk Management ("CBRM") Framework. The ACA methodology assigns health index scores to assets based on an observable condition variable. These scores are categorized within five health index bands ("HI1" to "HI5") to support project planning. Asset condition demographics are a strong indicator of future asset performance and reliability. Toronto Hydro aims to keep assets within the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands stable, with a particular emphasis on managing the shorter-term risks associated with HI4 and HI5 assets. The ACA allows Toronto Hydro to use data collected through inspections to establish a numerical representation of the condition of an asset by considering factors such as operation, degradation and lifecycle. The health score of an asset helps Toronto Hydro optimize asset replacement plans by indicating whether an asset has a higher or lower probability of failure than age alone would indicate. The ACA model also allows the utility to project future asset condition at an aggregate population level, which supports effective investment program pacing during the planning process.

Toronto Hydro is implementing probability of failure curves to derive a stronger and more objective relationship between condition and functional failures. Toronto Hydro's Probability of Failure methodology uses historical failure data in conjunction with the generated health scores from ACA.

In addition to ACA data and the development of probability of failure curves, asset age has a strong correlation with the likelihood of asset failure. Its simplicity and availability make it an informative source of data for system-wide analysis (e.g. reliability forecasting), particularly for longer time horizons. Toronto Hydro considers age by leveraging its Assets Past Useful Life ("APUL") analysis, which determines the proportion of assets currently past their useful life and expected to be without investment in the next five years. This analysis is done at the system level and for individual asset classes and is used to inform the pacing of renewal programs to ensure long-term stability/sustainability in combination with asset condition where available.

ACA, probability of failure and age are leading indicators of failure, and, by extension, the future reliability, safety, and environmental performance of Toronto Hydro's system. As noted above, Toronto Hydro also considers historical reliability – a lagging indicator of performance – in its asset needs assessment. Actual reliability helps to identify areas of poor or worsening performance and is a useful input in project prioritization. Historical reliability can also be a leading indicator of asset failure in specific circumstances.

Toronto Hydro also considers the potential consequences of failure when assessing asset needs. For example, an air-insulated pad-mount switch that is known to carry a higher risk of flashover compared to other pad-mount switches, posing employee and public safety risks, has a heightened consequence of failure and is therefore a higher priority for replacement.

2. System Growth & Capacity Needs

Toronto Hydro determines capacity and connection needs through the System Peak Demand Forecast, load connections forecasting, generation connections forecasting, and the Regional Planning process.

The 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") is developed using a driver based, top-down forecasting methodology and is fundamental to the capacity planning process, including the stations capacity planning process which enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. It forecasts the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid. The System Peak Demand Forecast considers new load connections, increased distributed energy resources ("DERs"), electrification of transportation and fuel switching. Further information on the System Peak Demand Forecast can be found in Section D4.

To prepare for growth and electrification in the City of Toronto, Toronto Hydro has adopted additional growth and electrification drivers into its System Peak Demand Forecast. The inputs include (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city.

Furthermore, in preparation for the 2025-2029 investment planning cycle and as a way of complementing and further contextualizing the capacity planning process, Toronto Hydro introduced the Future Energy Scenarios ("FES") model. FES is a bottom-up, consumer choice model that produced projections for peak load (kW), generation (kW), and energy consumption (kWh) under a variety of potential energy system transformation scenarios. Toronto Hydro's goal for the FES project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on FES can be found in Section D4, including a detailed discussion in the associated Appendix A.

In addition to the System Peak Demand Forecast, there are load and generation connections forecasting processes, which result in forecasts of the amounts of expenditures required to accommodate anticipated load and generation customers.

The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed energy resources ("DER") connections to the distribution system following legal and regulatory obligations under various statutes and codes. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers. Toronto Hydro's primary objective in this program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. See Exhibit 2B, Section D2 for more details.

Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code, and in coordination with Hydro One Networks and the IESO. Toronto Hydro continues to see interest in solar generation, as customers seek to reduce bills (through the Net Metering program) and achieve ESG objectives.

Finally, the Regional Planning Process is a key element of distribution system planning and stations-level planning in particular. Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the Central Toronto Integrated Regional Resource Plan, led by the Independent Electricity System Operator, and in the Regional Infrastructure Plan for Metro Toronto Region and GTA North Region, led by Hydro One Networks Inc. Additional details on the Regional Planning process are discussed in Section B2.

3. *Grid Modernization*

Toronto Hydro is at an important turning point in its modernization journey. A confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. DERs) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Toronto Hydro's overarching grid modernization plan is detailed in the Grid Modernization Strategy section found in Section D5. This strategy is the result of a cross-functional strategic planning effort undertaken in parallel with the typical business planning process over the course of 2021 and 2022. The focus and pacing of the investments featured in the Grid Modernization Strategy were informed by various strategic inputs, including customer and stakeholder engagement, government and regulatory policy, energy transition outlooks (including Toronto Hydro's own Future Energy Scenarios), engagement with industry groups and experts, publicly available literature regarding modernization efforts in leading jurisdictions (including examples of utilities and jurisdictions actively pursuing Distribution System Operator, or "DSO", capabilities), and an assessment of Toronto Hydro's existing grid modernization maturity versus the desired future state in 2030 and 2035. As detailed in the Grid Modernization Roadmap, Toronto Hydro has categorized these capability-building investments into three broad categories:

- **Intelligent Grid:** updating the existing distribution grid and introducing automation to deliver reliability and resiliency improvements, enhance system observability, and enable enhanced real-time decision-making;
- **Grid Readiness:** preparing the distribution system and operations to integrate DERs and leverage Non-Wires Solutions; and
- **Asset Analytics & Decision-making**: building on existing and future data sources and telemetry (sensors) to create value-added analytics and tools for enhanced planning, decision-making, and customer and stakeholder engagement

The Grid Modernization expenditure plans for 2025-2029 are integrated throughout Toronto Hydro's investments programs in Sections E5-E8. For a comprehensive guide to where specific modernization expenditures are found, please refer to Exhibit 2B, Section D5 and Section E2.

D1.2.1.3 Portfolio Reporting

As part of the IPPR process, Toronto Hydro monitors and reports on the progress of capital programs, which includes program level expenditures, project-specific execution status and project expenditures. The utility monitors changes in system-level outcomes (e.g. average reliability) and the effects of specific programs on specific outcomes (e.g. the reduction in the number of poles in end of serviceable life condition) during the Performance Measurement stage of the AM Process. This performance information is available to Toronto Hydro's planners to assess the benefits of the program to-date and identify necessary pacing and prioritization adjustments to meet objectives or emerging needs in future years.

D1.2.1.4 Portfolio Planning

The final piece of the annual IPPR Process is the development of the plan itself. Toronto Hydro planners use information from the Asset Needs Assessment and the Portfolio Reporting Process to develop capital investment and maintenance plans that support the achievement of the utility's asset management strategies and outcomes in alignment with customer needs and preferences.

1. *Capital Programs*

Toronto Hydro develops capital programs that address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility develops the programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, tackle resiliency and business continuity risks, improve contingency constraints, and make necessary day-to-day operational investments. For the purpose of structuring the 2025-2029 business planning approach, these programs are categorized into the following four focus areas:

- Growth and City Electrification;
- Sustainment and Stewardship;
- Modernization; and
- General Plant.

On overview of these capital programs is provided in Section E2. A summary of how these programs map to the OEB's investment categories of System Access, System Renewal, System Service and General Plant can be found in Section E4 of the DSP.

2. *Maintenance Programs*

Toronto Hydro's maintenance planning process is designed to assess the condition, extend the life, and maintain the reliability of distribution assets. The utility designs its maintenance programs to extract the maximum value from existing assets. Maintenance typically occurs on set frequencies derived from Reliability Centered Maintenance ("RCM") standards and the OEB's minimum inspection requirements in Appendix B of the Distribution System Code ("DSC").

Toronto Hydro has four major categories of maintenance:

- **Preventative Maintenance:** Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.
- **Predictive Maintenance:** Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.
- **Corrective Maintenance:** Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after emergency response crews have restored power following an outage. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.
- **Emergency Maintenance:** Involves the urgent repair or replacement of equipment when the equipment fails, often causing power disruptions to Toronto Hydro customers.

The details of the maintenance programs in these categories can be found in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro ensures that capital and maintenance programs are coordinated by planning and reporting on both activities within the IPPR process. Maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated. For example, Toronto Hydro completed its planned replacement of Automatic Transfer Switches and Reverse Power Breakers as of 2022. With the elimination of these asset classes, maintenance plans were modified accordingly.

3. *Pacing and Prioritization*

Toronto Hydro paces its expenditure plans to support the achievement of multi-year outcome objectives (e.g. maintain or improve reliability over a number of years). Pacing decisions are informed by various leading and lagging indicators of risk and performance (e.g. asset condition demographics, reliability projections, reliability results), and an assessment of various risk mitigation alternatives, as discussed in Section D3.2.

Program expenditures are reprioritized annually based on actual accomplishments and measured performance relative to the multi-year plan, as well as ongoing analysis of evolving system, customer, and stakeholder needs. Toronto Hydro prioritizes projects within and across programs in accordance with anticipated project benefits, estimated costs, and an assessment of execution capabilities and constraints. On this basis, the lowest priority projects are deferred to future years, and the projects that offer the greatest value-for-money relative to the utility's customer-focused objectives are scheduled for execution.

D1.2.2 Scope and Project Development

The scope and project development component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates.

The investment proposals from IPPR identify and prioritize the assets or issues that require intervention within each capital program. As part of the early stages of scope development, Toronto Hydro identifies the assets and issues in discrete geographical locations through the use of decision support tools. The utility considers alternatives while developing a scope, which include various engineering options available to address an issue. The utility then evaluates the options with consideration for risks, required performance, customer preferences, effects on third parties, adjacent investments, reconfiguration opportunities, and the overall costs versus benefits. Finally, the utility selects the preferred option for the specific area or issue being addressed, and collects and summarizes asset information for replacement or refurbishment along with high-level specifications for new assets to be installed as part of a conceptual design. This constitutes the initial scope of work.

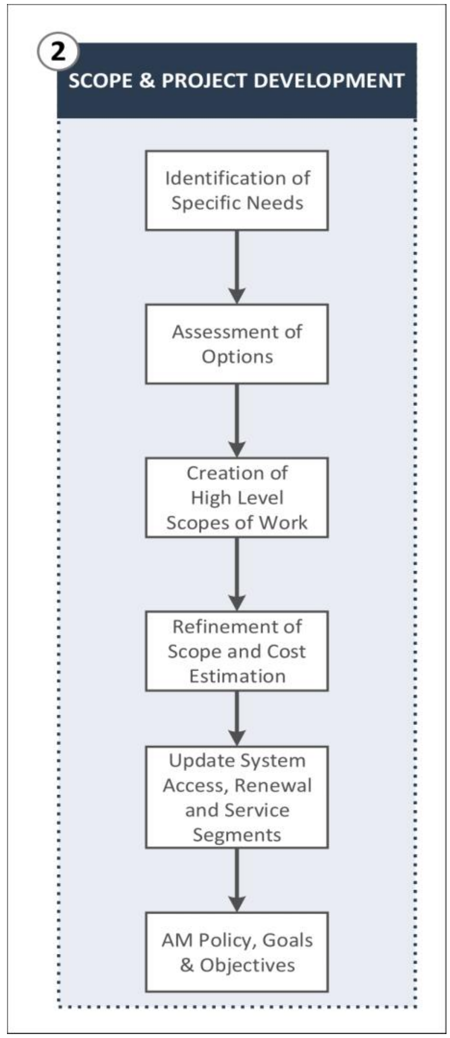


Figure 5: Scope and Development Stage

The next step is the project development stage, during which a cross-functional team of engineers, designers and field staff take the initial scope of work, assess feasibility and field conditions and execution risk. Project Development then produces refined scopes of work, preliminary designs and estimates, and aligns projects with execution work programs to allow for the most efficient use of resources. The project development team engages with internal and external stakeholders to ensure project timelines can be met, and to avoid conflicts and delays when a project is undergoing construction.

Where appropriate, the project development phase may break an original scope of work into smaller project phases for execution. This could be done for various reasons, including coordination with other work in the system, or to meet external constraints related to the location or the type of work. In the project development phase, the utility also undertakes initial project enabling tasks such as acquiring permits and coordinating with third parties prior to beginning final project design and construction. This helps to avoid design and scheduling uncertainty that can arise later in the process. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign.

D1.2.3 Program Management and Execution

The program management and execution stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

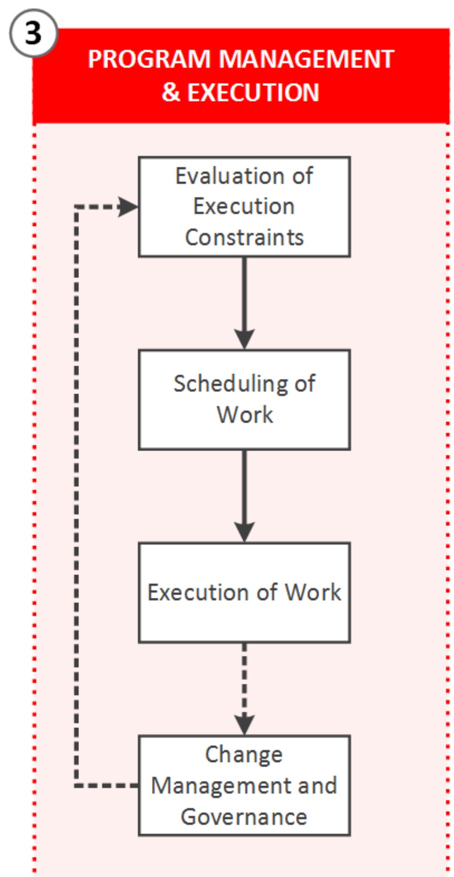


Figure 6: Program Management and Execution Stage

The "evaluation of execution constraints" stage considers multiple factors such as available resources, road moratoriums, switching restrictions, and coordination opportunities. Program managers, in coordination with system planners and in alignment with strategic objectives, select a prioritized mix of projects to be executed in a given year. Some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. Prioritization of work aims to balance renewal work with the emerging needs of the system. Toronto Hydro anticipates improvements in both the efficiency and effectiveness of this stage of the planning process as it continues to implement and integrate its new EAIP optimization tool.

Once Toronto Hydro develops an execution plan, the actual execution of work is monitored from the detailed design stage through the construction stage. Projects are closely tracked to proactively identify and manage risks that may impact the successful delivery of the planned work.

Toronto Hydro monitors changes to projects through a change management and governance process. This process includes monthly executive performance reporting, key program status reporting, change request process management, project variance analysis, and numerous metrics to drive process adherence and continuous improvement. Depending on the magnitude of a required change to a project's cost, schedule, or scope of work, the change may require a detailed assessment of alternatives and formal approval from senior management and the executive team before proceeding.

Exhibit 4, Tab 2, Schedule 10, Section 8 provides further details about the processes utilized in the Program Management and Execution stage of the AM Process.

D1.2.4 Performance Measurement

The final stage of the AM Process is to monitor the performance of the investment program, and to determine to what extent projects have contributed to expected outcomes. These results feed back into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives as appropriate.

Some key examples of outcome measures that Toronto Hydro tracks in relation to the capital and maintenance expenditure plans include:

- Asset Health Index;
- Reliability (e.g. SAIDI and SAIFI);
- Program Accomplishments (e.g. box poles removed)

Further details on Toronto Hydro's performance measures for the 2025-2029 DSP are provided in Section D1.2.1.1 and Section E2.

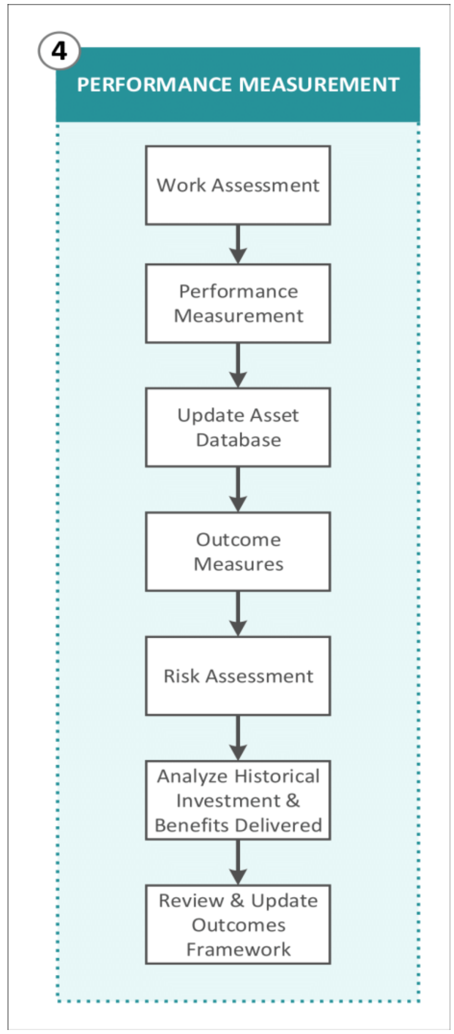


Figure 7: Performance Measurement Stage

D1.2.5 Standards and Practice Review

The Standards and Practice Review is driven by the need to evaluate particular standards and products to improve work execution and manage safety risks. This process influences three stages of the AM Process as planners, designers, and crews rely on this process to identify what equipment is available to them and its appropriate use. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety.

1) **New and revised standards:** Toronto Hydro routinely introduces new standards and revises existing standards to ensure safe and effective work execution. New standards are created in response to a number of drivers, including but not limited to: (i) climate change risks; (ii) process or productivity improvements; (iii) equipment quality; and (iv) safety risks. When Toronto Hydro revises a standard, other documents, such as the Standard Design Practices followed by project designers, are updated to align with changes made.
2) **New products:** Introducing new products enables more efficient, safe, and reliable service to customers. Product requests are reviewed to ensure alignment with business needs, that the appropriate stakeholders are engaged, and that the product satisfies Electrical Safety Authority ("ESA") requirements for major and minor equipment approval. The need for a new product can be initiated for a number of reasons, including: (i) safety; (ii) productivity; and (iii) reliability. For example, Toronto Hydro plans to install reclosers on the trunk and laterals of feeders that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions, resulting in reduction in overall outage times and improvement in system resiliency.
3) **Refurbishment and replacement of equipment:** When major equipment, such as transformers, network protectors, and switches, is returned from the field, Toronto Hydro evaluates, inspects, and tests them to determine whether the asset can be reused (i.e. repaired or refurbished) or should be replaced (i.e. scrapped).
4) **Quality improvements:** When a product that is not near end-of-life is returned from the field because of failure, it is investigated to determine the root cause of the failure. Investigations are conducted in-house, by an expert third party, or by the original equipment manufacturer. If a manufacturing quality issue is discovered, the manufacturer is notified and requested to

make modifications to address the issue. If an installation quality issue is discovered, corrective and preventative actions include standards revisions, procedure changes, and additional training.

5) **Standard Design Practices:** The Standard Design Practices ("SDP") document provides guidance and instructions for the design of Toronto Hydro's distribution system. The SDP instills safety by design, enforces construction standards, and ensures alignment with business strategies and consistency between projects. The DSP set outs general guidelines with respect to technical matters, and refers to construction standards for specific details.

6) **Industry standards**: Toronto Hydro seeks to align with industry standards and best practices wherever possible. This avoids unnecessary custom-made products which can drive up costs and maintenance complexity. Toronto Hydro is part of an Inter-Utility Standards Forum ("IUSF"), through which utilities collaborate on solutions to common problems and develop common equipment specifications. Toronto Hydro is also a member of numerous standards committees of the Canadian Standards Association and the Institute of Electrical and Electronics Engineers.

D1.3 Asset Management Process Enhancements

Toronto Hydro's AM process continues to evolve. The utility is continuously enhancing its approach to asset management to ensure the process and strategies remain aligned with the needs of its customers and the distribution system.

The recent progression of Toronto Hydro's AM process is described in the following two sections:

- D1.3.1 – Enhancements during previous filing period (2015-2019); and
- D1.3.2 – Enhancements during the current filing period (2020-2024).

D1.3.1 Past Enhancements (2015-2019)

Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 8 below. The following section provides additional details on key process improvements.

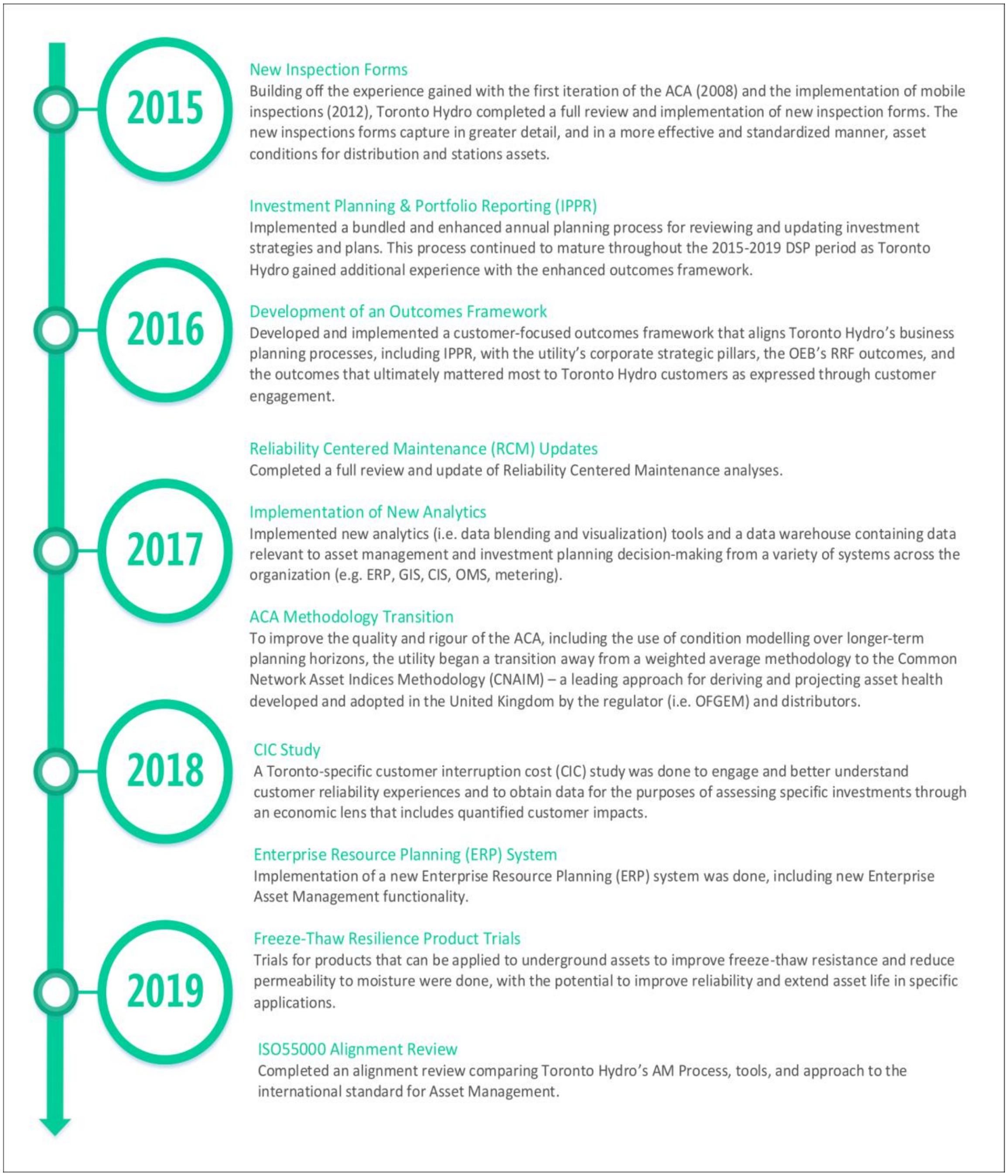


Figure 8: Past Enhancements of the AM Process (2015-2019)

D1.3.2 Recent Enhancements (2020-2024)

Figure 9 outlines improvements to Toronto Hydro's AM Process over the 2020-2024 period.

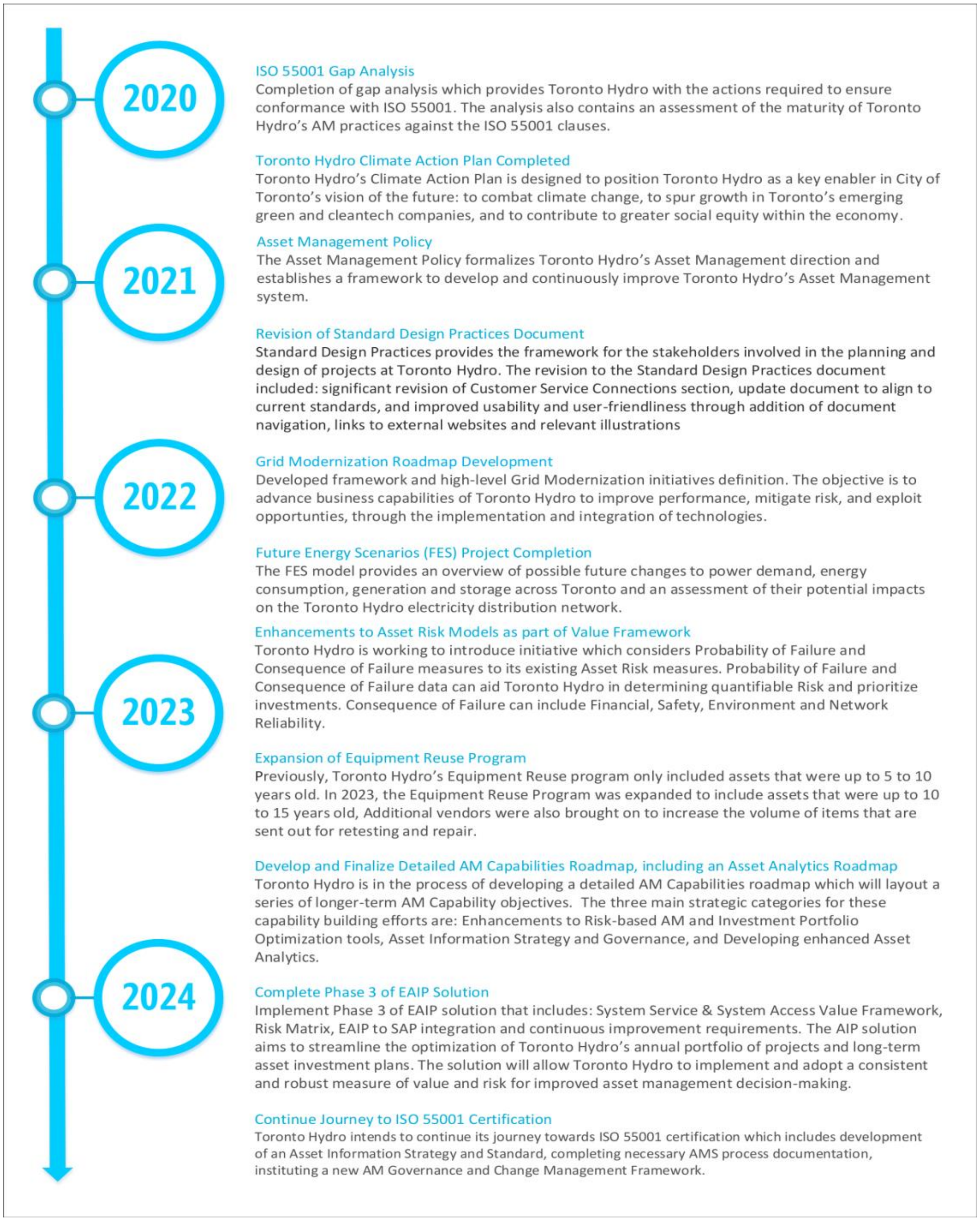


Figure 9: Recent Enhancements of the AM Process (2020-2024)

D1.3.2.1 Condition-based Risk Management Update

In 2017, Toronto Hydro transitioned from the ACA methodology originally adopted in 2008 to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons.

The model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology, known in the United Kingdom (where it originated) as the Common Network Asset Indices Methodology ("CNAIM"). This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, Ofgem. In terms of the functional outputs of the model, the methodology provides a reliable and detailed calculation of condition score for every applicable asset based on the most recent inspection information and an asset class's unique requirements. The methodology further facilitates the ability to project and calculate future health scores for assets which provides information on asset demographics that can be used to evaluate proposed investment strategies over longer-term periods. Since the establishment of the methodology in 2017, the health score calculation and future forecasting methodology has remained largely consistent, with certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

This model provides incremental benefits at the strategic level by facilitating projections of asset condition demographics by asset class. This allows Toronto Hydro to assess the current and future condition profiles of an asset class to better calibrate the level of investment necessary to either maintain or improve the amount of failure risk associated with its aging, condition and deteriorating asset base over time.

Toronto Hydro is currently working to introduce a risk-based value framework into its EAIP tool. Under the umbrella of this initiative, Toronto Hydro is in the process of developing and implementing a fully quantified risk value for each unique asset based in part on the core principles and methodologies of the CBRM framework. Arriving at a quantified risk value involves multiplying the Probably of Failure for an asset – which is derived from its Asset Health Score (or age when condition is not available) – by a Consequence of Failure (also know as its "criticality") which can be expressed in dollars. Toronto Hydro is currently developing Consequence of Failure models that will include impacts such as financial, safety, environmental and reliability outcomes. Toronto Hydro is currently on track to implement this value framework in time for the beginning of the 2025-2029 period.

Appendix A to section D3 of the DSP provides a detailed discussion of recent and ongoing enhancements to the model, and condition results by major asset class.

D1.3.2.2 Data Consolidation: Data Warehousing for Engineering Analytics

Toronto Hydro is currently performing improvements to its engineering data warehouse to streamline data access, and perform "big data" calculations that can support planning and system investment strategies. In parallel, the utility is further leveraging data blending and analytics software, and has integrated software into business processes to improve productivity and drive new insights.

As part of this effort, Toronto Hydro is implementing an Engineering Asset Investment Planning ("EAIP") solution to streamline the optimization of Toronto Hydro's annual portfolio of projects and long-term asset investment plans. The solution will allow Toronto Hydro to implement and adopt a consistent and robust measure of value and risk for improved asset management decision-making.

The implementation of EAIP will provide an efficient interface for project creation and integrates components of both the scope and work package. Moreover, the EAIP solution provides a centralized and standardized repository for asset data, business cases, project outcomes, work packages and integrates with other information sources like the utility's ERP and GIS systems.

As part of the Asset Analytics & Decision-making portfolio within the Grid Modernization Roadmap, Toronto Hydro plans to integrate relevant enterprise systems into a fully harmonized asset data registry. Toronto Hydro also plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations. The portfolio is discussed in detail in Exhibit 2B, Section D5.

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Avenue to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. As shown in Figure 1 below, Toronto Hydro's service territory can be divided into two geographic areas: (i) an urban centre in downtown Toronto with a high customer density and a large financial and entertainment district; and (ii) a suburban area around downtown Toronto with a lower customer density, which is colloquially referred to as the "Horseshoe" area.

Figure 1: Areas of the Toronto Hydro Distribution System

The following subsections discuss the characteristics of Toronto Hydro's service territory, including its customers and load growth profiles, climate and weather, and economic profile. Section D2.2 provides a detailed description of the utility's asset demographics, system configurations, and asset condition, and Section D2.3 provides a summary of system utilization.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies approximately 790,000 customers with a peak load of 5,191 MVA as of 2022. Toronto Hydro has been experiencing steady customer growth for many years, as shown in Figure 2.

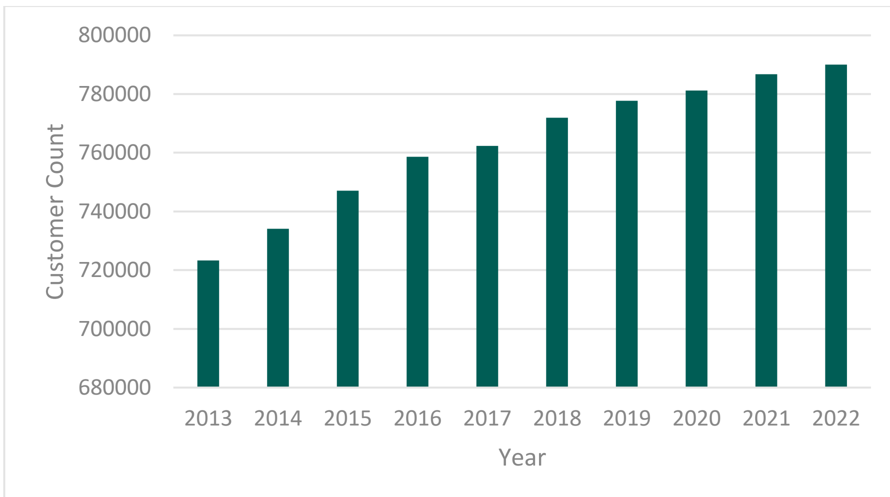


Figure 2: Historical Toronto Hydro Customer Counts

Despite steady customer and population growth, overall system peak load has remained relatively steady in recent years at approximately 5,000 MVA, as shown in Figure 3. It is important to note that system peak load varies with temperature.

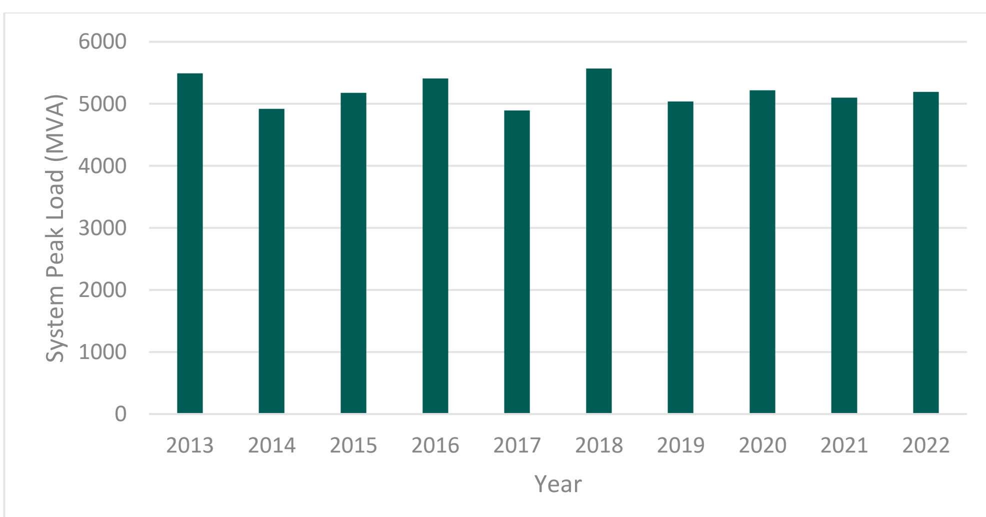


Figure 3: Historical Toronto Hydro System Peak Loading

Toronto is one of the fastest growing cities in North America with an additional 500,000 people expected by 2030.[1,2] Since 2015, the city of Toronto has led the crane count in the United States and Canada.[3] As of Q1 2023, Toronto has 238 cranes of which 58 percent are residential buildings and 29 percent are commercial/mixed use (see Figure 4 below).

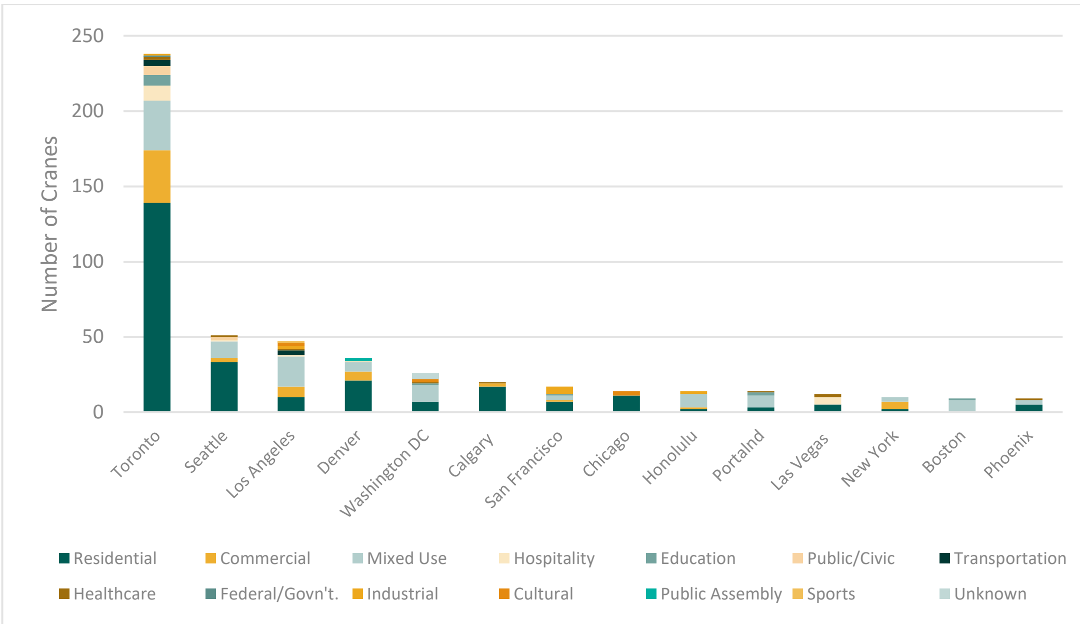


Figure 4: RLB Crane Index - Q1 2023

The city continues to experience highly concentrated load growth in certain pockets of the city due to a high number of large building developments. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue as shown in Figure 5. Consequently, this growth is pushing certain distribution and station equipment

[1] Centre for Urban Research and Land Development, Toronto Second Fastest Growing Metropolitan Area, City of Toronto the Fastest Growing Central City, in the United States/Canada in 2022, https://www.torontomu.ca/centre-urban-research-land-development/blog/blogentry7311/, Research found City of Toronto to be the fastest growing central city in the United States and Canada.

[2] Toronto Public Health, Toronto's Population Health Profile: insight into the health of our city https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf, Toronto's population increased by 2.3 percent between 2016 and 2021. By 2031, Toronto's population is expected to exceed 3.4 million people. 2021: 2,794,356 2031 Projection: 3,460,604.

[3] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023, https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

to capacity. Infrastructure renewal and upgrades are required in these areas to support growth while maintaining reliability and system resiliency.

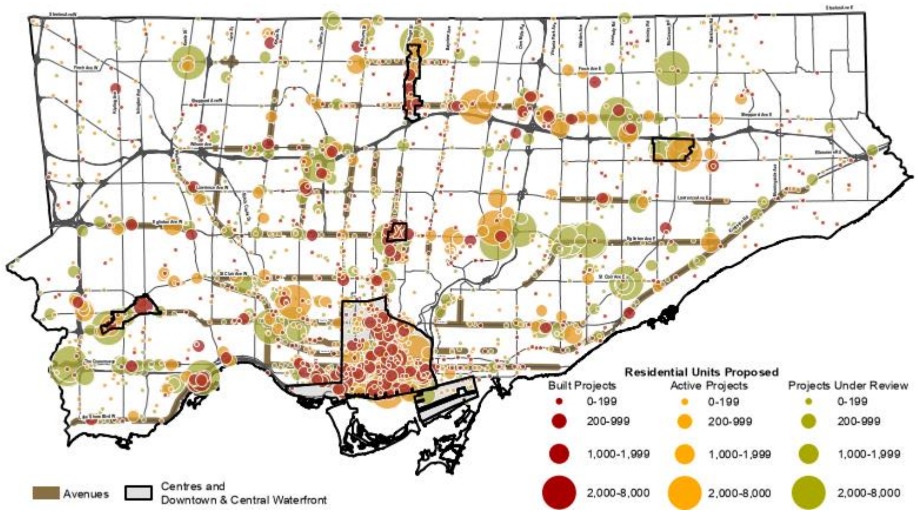


Figure 5:[4] **Growth Nodes within the City of Toronto**

Toronto is also Canada's largest data centre market.[5] With respect to data centre connections, Toronto Hydro connected approximately 102 MW of incremental demand load during the 2020-2024 period, and approximately 198 MW is forecasted to be connected during the 2025-2029 period.[6] According to Toronto Hydro's Peak Demand forecast, by 2031, data centres and EVs will contribute approximately 10 percent of the overall peak demand of the downtown region.[7]

Going forward, Toronto Hydro expects growing pressure on the distribution system, amplified by the accelerated adoption of Electric Vehicles ("EVs") and growth in electrified heating. The utility foresees these electrification drivers pushing the overall system peak higher in the future as well.

Growth in Electric Vehicles

Electric Vehicle ('EV') adoption is accelerating across the globe, driven in part by policies intended to reduce greenhouse gas emissions from the transportation sector. The Canadian government has

[4] City of Toronto, Development Pipeline 2022 Q2 (February 2023), https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[5] Cushman & Wakefield, 2022 Global Data Center Market Comparison, (2022), https://www.cushmanwakefield.com/en/insights/global-data-center-market-comparison
[6] Exhibit 2B, Section E5.1
[7] Exhibit 2B, Section D4.

announced a new light-duty vehicle sales goal targeting a 100 percent share for EVs by 2035, including interim targets of at least 20 percent by 2026 and 60 percent by 2030. To support its goals, the Government of Canada will invest $1.7 billion to extend incentives for light-duty vehicles, $400 million for charging stations, and $547.5 million for a purchase incentive program for medium-and heavy-duty vehicles.[8] The province of Ontario is the third largest vehicle-producing jurisdiction in North America.[9] Several automotive plants in Ontario are being prepared to build EVs and related components.[10]

Figure 6 shows that the number of new EV registrations in Ontario has been increasing over the last six years. For comparison, the total number of vehicle registration of all fuel types in Ontario have seen a steady decrease from 798,500 in 2018 to 594,500 in 2022. Toronto Hydro's Future Energy Scenarios ("FES") modelling results provide a range of plausible EV adoption rates in Toronto out to 2050 for three scenarios: Low, Medium and High EV adoption scenario. According to FES modelling, the number of Battery Electric Vehicles is projected to grow to approximately 1.8 million by 2050 in the Medium and High scenarios, and approximately 1.2 million by 2050 in the Low scenario. These results are discussed in the Future Energy Scenarios report.[11]

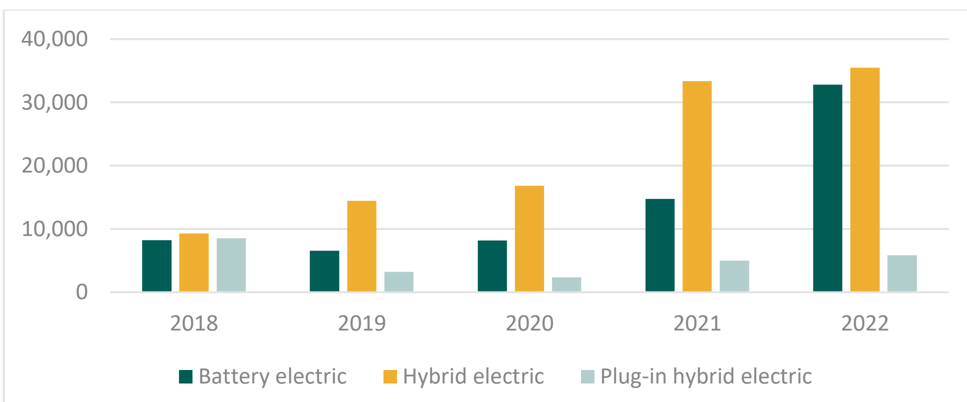


Figure 6:[12] Number of New Vehicle Registrations by Fuel Type in Ontario, as of Q4 2022

[8] Government of Canada, 2020 Emission Reduction Plan – Sector-by-sector overview (2022), https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6
[9] Invest Ontario, Automotive (2022), https://www.investontario.ca/automotive#intro
[10] Canadian Metalworking, Canada jumps into electric vehicle industry (2021) https://www.canadianmetalworking.com/canadianmetalworking/article/madeincanada/canada-jumps-into-electric-vehicle-industry.
[11] Exhibit 2B, Section D4, Appendix B.
[12] Statistics Canada, New Motor Vehicle Registrations (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010002401

Growth in Electrified Heating

Heat pumps are an energy-efficient alternative to building heating and cooling systems. The adoption of heat pumps will transition gas and other home heating systems to use electricity. The transition of homes and buildings from natural gas furnaces to heat pumps is a key part of the City's TransformTO Net Zero Strategy.[13]

The Government of Canada has introduced incentives such as the Greener Home Grant, which grants up to $5,000 towards heat pumps and other energy-efficiency measures. In the City of Toronto Climate Change Perceptions Research, 44 percent of homeowners in Toronto say that they are likely to install an air-source heat pump. Figure 7 illustrates the market share of heat pumps in residential sector heating systems has been increasing in recent years. FES modelling explored uptake of electric heat pumps rates, which is discussed in the Future Energy Scenarios report.[14] According to the FES report, widespread uptake of heat pumps, along with technologies such as electric vehicles, are expected to be primary drivers of increases in peak demand and shifting of network peak from summer to winter in the 2030s.

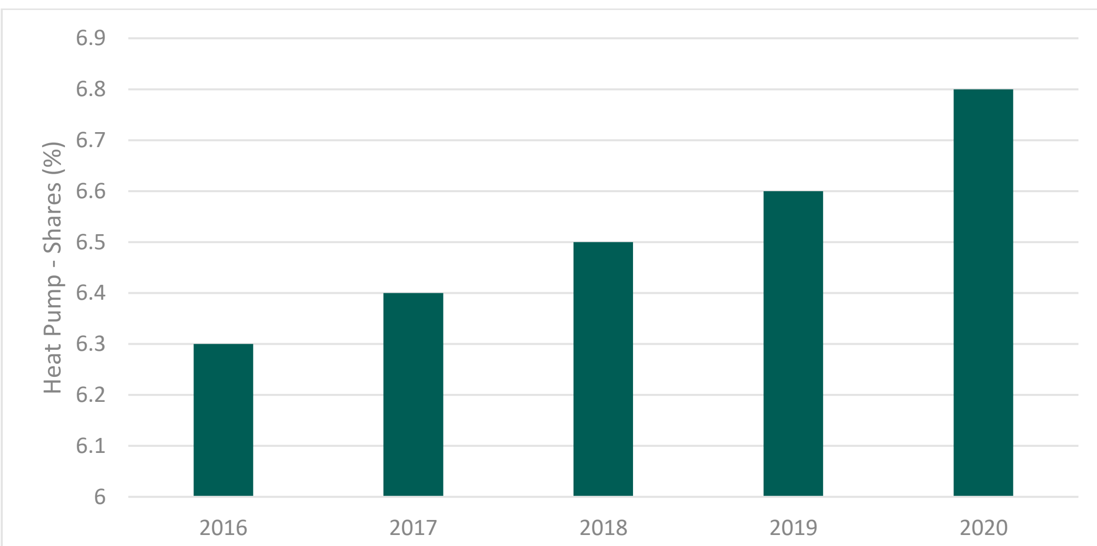


Figure 7:[15] Market Share of Heat Pumps in Residential Sector Heating System in Ontario

[13] City of Toronto, 2021 Net Zero Existing Building Strategy, (2022), https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-168402.pdf
[14] *Supra* note 10, Section 4.2.
[15] Natural Resources Canada, Comprehensive Energy Use Database, (2023), Table 21, https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

To keep pace with the growing city and ensure appropriate distribution system capacity, especially in order to support electrification, the utility plans to continue actively investing in capacity through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Load Demand (Section E5.3);
- Generation Protection Monitoring & Control (Section E5.5);
- Non-Wires Alternatives (Section E7.2); and
- Stations Expansion (Section E7.4).

The utility's complimentary Grid Modernization Strategy is also central to cost-effectively maintaining reliability and improving resiliency in the face of accelerating growth in peak demand.[16]

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 110 times per year as opposed to 87 times per year currently.[17] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Weather conditions of high heat, high winds, heavy rainfall, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 8 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 25 years. In both cases it is observed that there is an increasing trendline over

[16] Exhibit 2B, Section D5.
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

the period. With respect to high wind days, an even steeper increase has been observed, and seven of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

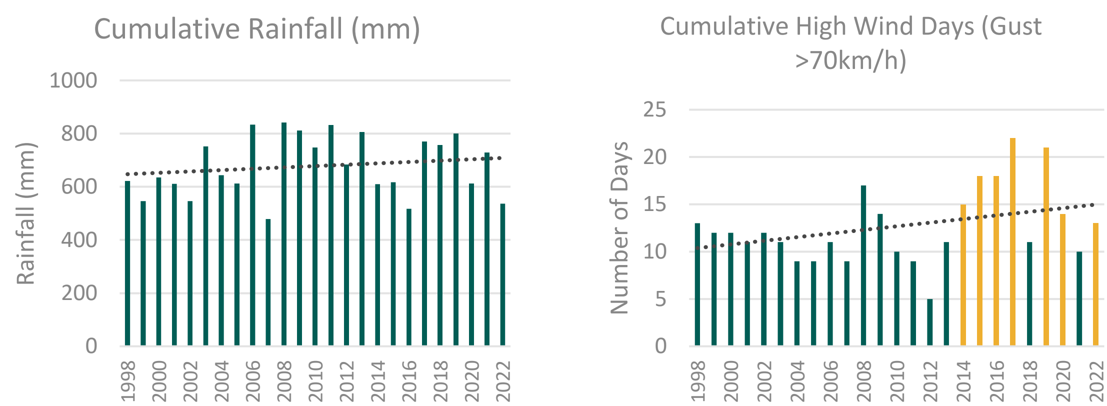


Figure 8: [18]Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto:

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[19]

These weather trends have increased reliability risks for the distribution system. Toronto Hydro analyzed system reliability data to understand the correlation between wind speed above 70 kilometres per hour, the number of forced outages on the overhead system, and SAIDI performance. This revealed a high correlation between wind speed above 70 kilometres per hour and the number of forced outages on the overhead system. It was also determined that higher wind speeds were correlated with increased SAIDI.

Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme

[18] Government of Canada, Weather, Climate and Hazard Historical Data http://climate.weather.gc.ca/historical_data/search_historic_data_e.html; Weather data compiled using Toronto Lester B. Pearson INTL A for January 1998 to June 2013 and Toronto INTL A for July 2013 to December 2022.
[19] *Supra* note 16.

cases, broken trees and the weight of ice accretions bring lines, poles and associated equipment to the ground.

The above-mentioned reliability risks are significant, as evidenced by an event that occurred on May 21, 2022. A major storm with wind gusts as high as 120 kilometres per hour swept through Toronto Hydro's service territory. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment. Approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) were without power during this event. Similarly, four weather-related major events occurred during April to July of 2018 due to wind storms and freezing rain. The events caused 382,286 Customers Interrupted and 1,173,338 Customer Hours Interrupted (discussed in Exhibit 2B, Section C).

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[20] The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

In 2022, Toronto Hydro updated the 2015 study to identify if any further work is required to update the adaptation measures.[21] The study utilized updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), along with IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. These probabilities were then assessed to determine the materiality by recalculating risk scores over the study period (from 2022 to 2050) following the PIEVC protocol. The results of the study provided that two climate parameters had probability changes as follows:

Climate Parameter	**Threshold**	**Frequency** (2030s)	**Probability** (Study Period)	**Probability Score** (Study Period)	**Probability Score Change** (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

[20] EB-2018-0165, Exhibit 2B, Section D, Appendix D.
[21] *Supra* note 16.

For each of the above climate parameters, an assessment was completed to determine how these changes in probability impacted the infrastructure asset classes, similar to the 2015 report. The following table provides the results:

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures greater than 40°C and 13 from Ice Storms/Freezing Rain greater than 25 mm).

Although the results observed a decrease in risk scores for these 23 interactions, given the uncertain nature of the climate projection data, the recommendation was to not relax any adaptation measures associated with extreme heat or freezing rain events from the 2015 study.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with more robust designs; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

In February 2023, CSA issued changes to it's Underground and Overhead Systems Standards related to Climate Change Adaptation. Toronto Hydro strives to meet and surpass these new requirements. Some impacts to Toronto Hydro design considerations include:

- Modification of standard pole loading analysis to accommodate extreme weather events in light of recent CSA updates; and
- Standardization of conversion of submersible transformers to padmounted transformers in residential rebuild projects, in order to mitigate the impacts of flooding.

The following 2025-2029 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro plans to reconfigure feeders and relocate assets away from the ravines and right of ways to improve accessibility for Toronto Hydro crew members and reduce vulnerability to outages in adverse weather conditions.
- Padmounted transformers will replace existing submersible units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will replace air-vented padmounted switches with more robust designs to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program will replace end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. The strategy focuses on accelerating the deployment of digital field and operational technologies that will enhance the utility's ability to address developing fault conditions in real-time, improve outage restoration capabilities and operational flexibility, and lay the groundwork for widescale grid automation beginning in 2030. Key investments include the deployment of technologies that will enhance real-time system observability (e.g. next generation smart meters;

overhead and underground line sensors; network condition monitoring technologies), enhance system controllability (e.g. SCADA-enabled switches and reclosers); and enable integrated and increasingly predictive/automated control of the distribution system (e.g. Advanced Distribution Management System or "ADMS"). For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

Toronto Hydro continues to be a partner of the City of Toronto in planning and preparing for the effects of climate change.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for approximately 20 percent of Canada's Gross Domestic Product ("GDP"). Its GDP growth has significantly outpaced the national average over the 2015 to 2019 period.[22] The city is the second largest financial service centre in North America.[23]

Toronto also has a diverse industrial and commercial base comprised of 14 key sectors including aerospace, design (e.g. fashion, interior), financial services, education, life sciences, technology, food, entertainment, and tourism.[24] The importance of Toronto's economy highlights the necessity of sufficient investments to ensure the delivery of value for distribution customers and to prepare for technology driven change.

Like many regions across the country and the world, Toronto's economy has recently faced significant inflationary pressures. Figure 9 shows the annual change in Consumer Price Index ("CPI") over the past ten years for the City of Toronto, Province of Ontario and Canada. CPI represents changes in prices as experienced by consumers. This figure illustrates the significant increases to CPI in recent years.

[22] Statistics Canada, Gross Domestic Product (GDP) at basic prices (2022), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610046801
[23] City of Toronto, Business & Economy, Strong Economy, https://www.toronto.ca/business-economy/invest-in-toronto/strong-economy/
[24] City of Toronto, Business & Economy, https://www.toronto.ca/business-economy/industry-sector-support/

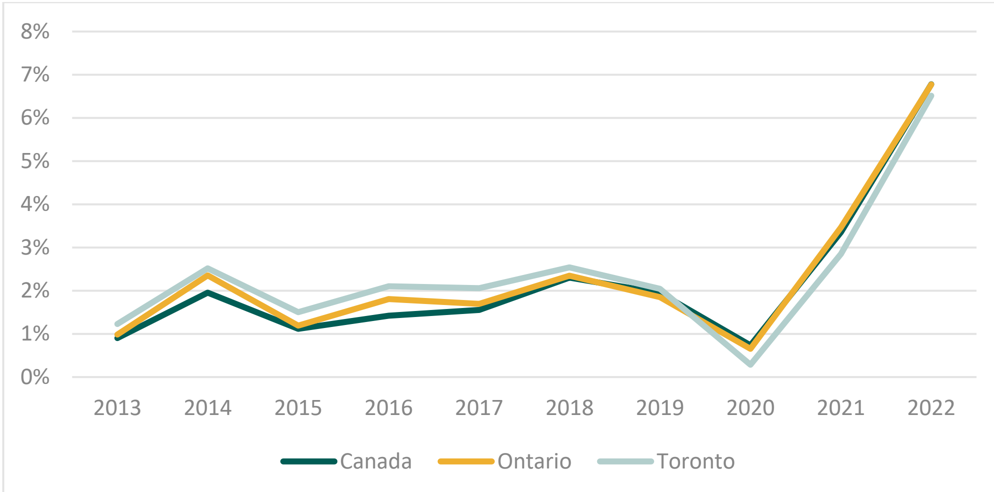


Figure 9: [25]Annual change in CPI over the past ten-year period

Similarly, Building Construction Price Indexes ("BCPI") provide change in prices over time that contractors charge to construct a range of new commercial, institutional, industrial and residential buildings. BCPI for non-residential buildings is relevant to Toronto Hydro's costs and has risen significantly in recent years. Figure 10 illustrates the average increase in BCPI for non-residential buildings for the City of Toronto.

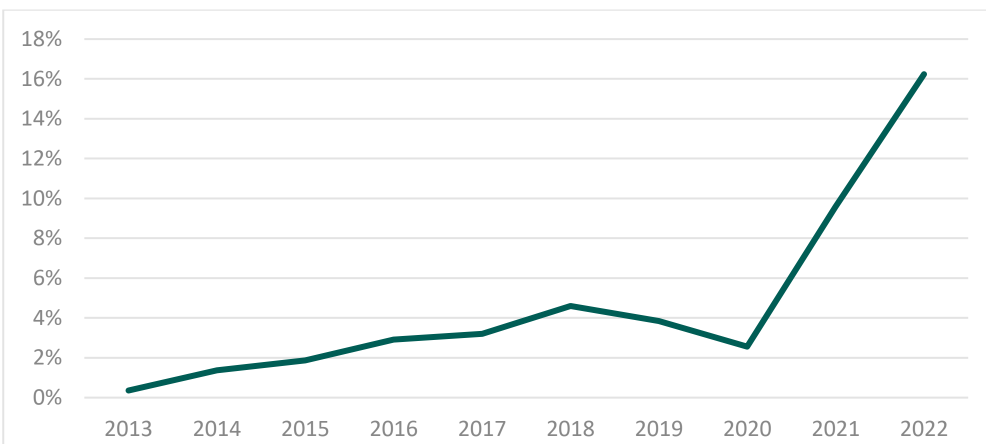
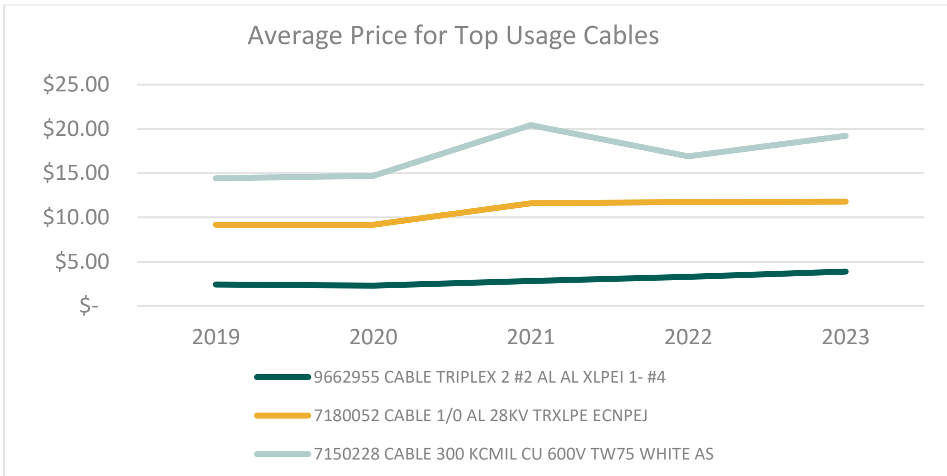


Figure 10: [26] Annual change in BCPI for non-residential buildings over the past ten-year period

[25] Statistics Canada, Table 18-10-0005-01 Consumer Price Index , annual average (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501
[26] Statistics Canada, Table 18-10-0276-01 Building Contruction Price Indexes (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810027601

In addition to increases in CPI and BCPI for non-residential buildings, Toronto Hydro also faces increasing commodity prices. Figure 11 illustrates the average price for some top usage equipment in Toronto Hydro.



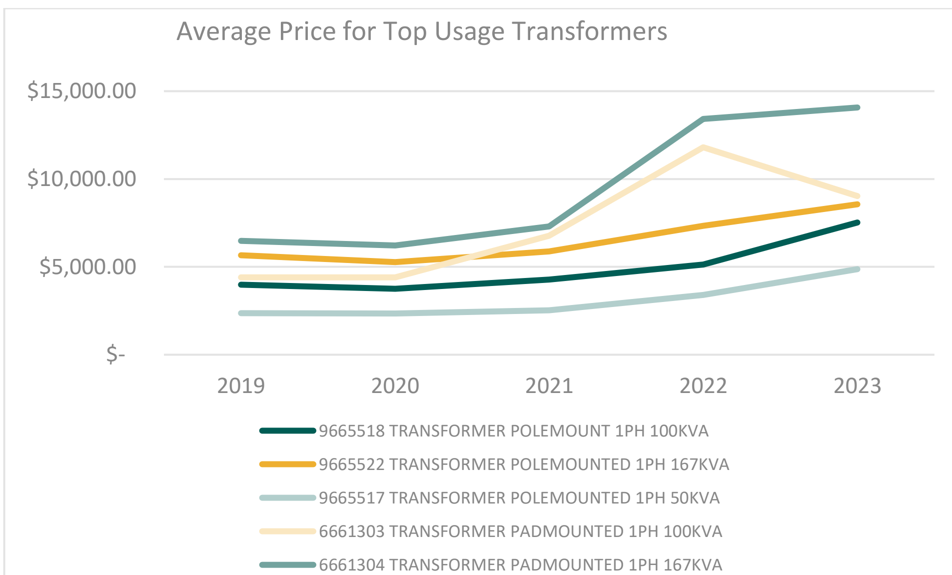


Figure 11: Average price for some top usage equipment in Toronto Hydro

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

One example is the City of Toronto's climate change action plan and long-term vision. A key pillar of this plan is the *TransformTO* Net Zero Strategy,[27] which identifies how the City plans to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. One of the major commitments of this plan is for 100 percent of vehicles in Toronto to use low-carbon energy by 2040. As part of achieving this goal, the City has made climate related investments for water, solid waste and parking. In addition, the City is making significant capital investments in the TTC, which includes vehicles such as buses, streetcars and subway cars.[28]

Toronto Hydro prepared a Climate Action Plan to support the City's objectives. The Climate Action Plan encompassed the areas of EV charging infrastructure, modernization of streetlighting, building electrification and energy efficiency, renewable energy, and energy storage.[29] Toronto Hydro has also established a target of achieving net zero for its own operations by 2040.

There are three climate action opportunities Toronto Hydro is pursuing to reach its objectives. Firstly, following the planning principles and forecasting approaches outlined in Section D4 of the DSP, Toronto Hydro plans to expand its existing electricity distribution business to build a grid that is capable of supporting the realization of the City's Net Zero Strategy. The second opportunity is for Toronto Hydro to create a new, non-rate-regulated Climate Advisory Services line of business to support the City's Net Zero Strategy by facilitating and stimulating the growth of emerging local cleantech markets. The third opportunity is pursuing modernization of outdoor lighting within the utility's existing unregulated streetlighting company.

Provincial and federal policy targeting greenhouse gas reductions is also a driver of technological change. Provincial energy policy, such as the Net Metering program, supports and incentivizes the connection of renewable energy projects to the local distribution system. As of the end of 2022, Toronto Hydro has connected 2,424 unique distributed energy resource ("DER") projects to its distribution grid, totaling approximately 305 MW of generation capacity.[30] As discussed in Section

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[27] City of Toronto, TransformTO Net Zero Strategy, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf
[28] See Exhibit 2B, Section E.
[29] Toronto Hydro, Climate Action Plan, https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942821
[30] Exhibit 2B, Section E5.1.

E3, Toronto Hydro anticipates steady growth in generation connections going forward and is planning to invest in necessary renewable enabling improvements, including monitoring and control technologies, and energy storage systems to facilitate this growth during the 2025-2029 rate period.

D2.2 System Demographics and Characteristics

Toronto Hydro's distribution system consists of a mix of overhead, underground, network, and stations infrastructure. This infrastructure operates at voltages of 27.6 kV, 13.8 kV, and 4.16 kV, and includes approximately 61,000 distribution transformers, 17,000 primary switches, 15,600 kilometres of overhead conductors, and 13,800 kilometres of underground cables as of 2022. Unless otherwise mentioned, asset demographic information provided herein is as of 2022.

The following sections provide details on these sub-systems and how each sub-system relates to Toronto Hydro's major asset management objectives. As discussed in Exhibit 2B, Section D3, Toronto Hydro manages its distribution infrastructure and plans capital investments and maintenance to achieve asset performance objectives, specifically, the attainment of applicable outcomes summarized in Section D1, and further detailed in Sections C and E2 of the DSP.

The following table and accompanying explanations introduce Toronto Hydro's sub-systems through the lens of a core subset of risk related asset management performance measures, all of which relate directly or indirectly to Toronto Hydro's outcomes.

Table 1: Asset Management Performance Indicators by System Type

System	**Oil Deficiencies** (Number of assets)	**Priority Deficiencies** (Number assigned)	**Customer Hours of Interruption** due to Defective Equipment	**Customer Interruptions** due to Defective Equipment	**Condition** [31] (Percentage of Assets in HI4 or HI5)	**Oil Containing PCBs** (Number of assets with oil containing or at risk of containing PCB)	**Age** (Percentage of Assets past Useful Life)	**Legacy Assets**
	Lagging Indicator of Performance				**Leading Indicator of Performance**			
Overhead	11 (3%)	3,074 *(24%)*	68,312 *(27%)*	117,175 *(33%)*	8.8%	3,076 (57%)	16%	2756 Box Construction Poles 6832 Customers Served by Rear Lot 502 km of 4.16 kV conductor
Underground	298 (88%)	8,955 *(71%)*	170,290 *(68%)*	230,661 *(64%)*	3.3%	2,278 (42%)	23%	721 km of Direct-Buried Cable 140 Transclosures[32] 985 km of PILC[33] Cable 176 km AILC[34] Cables 202 km of 4.16 kV cable
Network	21 (6%)	0 (0%)	0 *(0%)*	0 *(0%)*	4.0%	66 (1%)	23%	533 Non-Submersible Network Units 651 vaults without communication
Stations	8 (2%)	560 (4%)	10,636 *(4%)*	9,652 *(3%)*	3.1%	-	43%	346 legacy breakers at TSs[35] 558 legacy breakers at MSs[36]
Total	**338 *(100%)***	**12,589 *(100%)***	**249,238 *(100%)***	**357,488 *(100%)***	**7.1%**	**5,420 (100%)**	**25.2%**	-

Notes: All figures are 2022 year-end actuals, unless otherwise noted.

[31] See Exhibit 2B, Section D3, Appendix A for summary of results and details on updates to Toronto Hydro's Asset Condition Assessment.
[32] As a result of data improvement efforts, the transclosure population was updated to 140.
[33] Paper Insulated Lead Covered ("PILC") cable.
[34] Asbestos Insulated Lead-Covered ("AILC") cable.
[35] Transformer Station ("TS").
[36] Municipal Station ("MS").

- **Oil Deficiencies:** An oil deficiency is any observation related to oil (e.g. dried oil, oil leak) made during planned asset inspections. These are reported by inspectors when inspecting equipment and components that are known to or intended to contain oil. Oil deficiencies are an indicator of the likelihood of oil spills. The primary driver for this metric is to protect the environment from oil spills and to adhere to federal, provincial, and municipal legislation, regulations, and by-laws pertaining to the release of oil into the environment. Toronto Hydro strives to achieve zero oil leaks into the environment. Programs that contribute to the management of this measure are Preventative and Predictive Maintenance programs for oil filled equipment,[37] and capital programs that replace deteriorating oil filled equipment, including Underground System Renewal,[38] and Reactive and Corrective Capital (Section E6.7).[39]

- **Priority Deficiencies**: Toronto Hydro defines "priority deficiencies" as the subset of all equipment deficiencies that require intervention on a reactive or corrective basis. Between 2020 to 2022, Toronto Hydro identified around 45,000 deficiencies each year through planned inspections, responding to equipment failures and power interruptions, or through the course of day-to-day work. The total number of deficiencies are higher compared to the last rate application partially due to the inclusion of deficiencies corrected on site, which were not counted in the previous DSP. Priority deficiencies are deficiencies that pose a high risk to reliability, safety, or the environment and are assigned as priority 1 (P1), priority 2 (P2), or priority 3 (P3) for the purposes of addressing the deficiency. Each category corresponds to a level of risk (with P1 being the highest risk) and a timeline for repairing the deficiency or replacing the asset. Toronto Hydro has various programs (including Reactive and Corrective Capital, Corrective Maintenance, and Emergency Response) to address asset deficiencies, some of which have already resulted in asset failure.[40] Given the risks, timely and effective responses to priority deficiencies are non-discretionary and must be taken over short time horizons (i.e. less than six months). Identifying and responding to priority deficiencies in a timely manner is critical to meeting the utility's performance objectives for key outcomes such as SAIDI and SAIFI, and the utility's safety and environmental objectives.

[37] Exhibit 4, Tab 2, Schedules 1, 2, and 3.
[38] Exhibit 2B, Sections E6.2 and E6.3.
[39] Exhibit 2B, Sections E6.7.
[40] Exhibit 2B, Section E6.7 and Exhibit 4, Tab 2, Schedule 4-5.

The volume of corrective work requests has been increasing in recent years which has resulted in a growing backlog of P3 deficiencies that need to be addressed. This increase can be attributed to deteriorating asset condition and asset-related safety risks to crews or the general public, in addition to enhanced inspection forms and the introduction of new inspections. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which is expected to grow. To help manage this risk, the corrective work requests in the backlog have been further prioritized by level of risk within P3 priority, and by the primary and secondary impact of the deficiency.[41]

- **Customer Hours of Interruption ("CHI") and Customer Interruptions ("CI") (i.e. Outages)**: CHI and CI are measures of outage duration and frequency, scaled by the number of customers affected by each outage. Toronto Hydro uses this type of historical reliability data to identify priority project areas across all of its reliability-related programs, and to develop and pace investment program spending in order to improve key outcomes that the utility reports including SAIDI and SAIFI.

- **Assets with Material Deterioration or at End of Serviceable Life**: As described in detail in Section D3 and associated appendices, Toronto Hydro's asset condition assessment ("ACA") methodology assigns health scores to assets based on observable condition variables, and categorizes these scores within five health index bands ("HI1" to "HI5"). Asset condition demographics are a strong predictor of future asset performance. Over the long-term, Toronto Hydro is focused on managing the number of assets in the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands, with a particular emphasis on preventing significant increases in the most critical HI4 and HI5 bands.

- **PCBs**: Toronto Hydro defines "PCB at-risk equipment" as an asset that: (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"); or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCB). This measure excludes cables. Due the toxic and persistent nature of PCBs, Environment Canada's *PCB Regulations*[42] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City

[41] Exhibit 4, Tab 2, Schedule 4.
[42] PCB Regulations, SOR/2008-273, under the *Canadian Environmental Protection Act*, 1999.

of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.[43] Toronto Hydro plans to continue its efforts to address PCB at-risk equipment by 2025 through a combination of inspection and testing equipment under its maintenance programs,[44] and through targeted asset replacement in capital programs such as Overhead System Renewal,[45] Underground System Renewal,[46] Network System Renewal,[47] Stations Renewal,[48] and Reactive and Corrective Capital.[49]

- **Age**: Toronto Hydro monitors the percentage of its asset base that has passed useful life or will pass that milestone by the end of the next planning horizon. As a comprehensive indicator of failure risk across the system, this information is used for longer-term planning purposes. As of the end of 2022, Toronto Hydro's percentage of assets past useful life was 25 percent, with an additional 11 percent forecasted to reach expected useful life by the end of 2030, meaning that over a third of the utility's asset base is at or nearing the end of its typical useful life. By managing this measure over the long-term, the utility aims to provide predictability in the performance of key outcomes like reliability and safety for current and future customers, and to provide stability in costs, rates and labour resourcing by not allowing significant backlogs of asset replacement needs to accumulate.

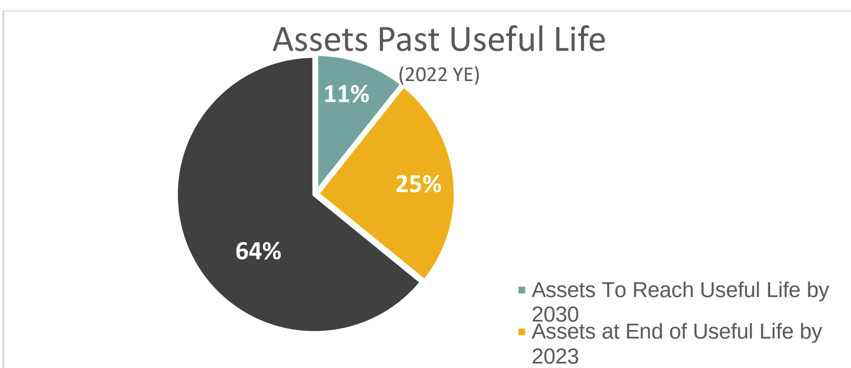

Figure 12: Assets Past Useful Life

[43] Toronto Municipal Code, Chapter 681 – Sewers.
[44] Exhibit 4, Tab 2, Schedules 1-4.
[45] Exhibit 2B Section E6.5.
[46] Exhibit 2B, Sections E6.2 and E6.3.
[47] Exhibit 2B Section 6.4.
[48] Exhibit 2B Section 6.6.
[49] *Supra* note 37.

- **Legacy Assets**: Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards. These assets often feature obsolete components with limited or no supplier or skilled labour support to maintain, repair or replace the assets, and carry elevated reliability, safety, or environmental risks. Additionally, lower voltage parts of Toronto Hydro's system are increasingly obsolete from a design perspective due to their inability to support the high levels of electrification and DER integration that the utility anticipates over the next 15-20 years. One of Toronto Hydro's asset management strategies is to eliminate all high-risk legacy assets within a specific and reasonable timeframe. The specific legacy assets are discussed further in the following sections as part of the overhead, underground, network, and stations systems descriptions. Table 2 above provides an estimate of the remaining volumes of certain key legacy assets across Toronto Hydro's different subsystems. For further details on specific legacy asset replacement and pacing, please see Exhibit 2B, Section E2.

The following sections provide a more detailed view of the overhead, underground, network, and stations sub-systems of Toronto Hydro's distribution system, including the age and condition demographics of the assets, and associated system challenges. Each section provides a further breakdown of how those sub-systems relate to Toronto Hydro's asset management indicators and measures discussed above.

D2.2.1 Overhead Grid System

The overhead system consists of poles, overhead conductors, overhead transformers, overhead switches, and other equipment including lightning arrestors, guying hardware, and wires. All of these assets are placed above ground in areas with sufficient space and clearance from overhead obstructions (e.g. trees and buildings). Advantages of using an overhead system are that it is cost effective and allows for more expeditious fault identification and outage restoration, given that all assets are out in the open and visible to crews. Disadvantages of this system are that it is prone to foreign interference from vehicles, trees, animals, and weather-related outages (i.e. caused by high winds or freezing rain), and requires adequate clearances to operate and maintain.

Figure 13: Overhead Distribution Transformer

The majority of Toronto Hydro's overhead system is operated at 27.6 kV and 13.8 kV, but a subset of the overhead system operates at 4.16 kV. The overhead system consists of approximately 166,500 poles, 7,400 overhead switches, 30,000 overhead transformers, 4,000 circuit-kilometres of overhead primary, and 11,300 circuit-kilometres of overhead secondary conductors as of 2022.

Asset management activities related to the overhead distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 14 provides the age demographic distribution of major overhead assets. As of 2022, approximately a quarter of poles are beyond their typical useful life of 45 years. Without any intervention, Toronto Hydro projects that the percentage of poles having reached or exceeded useful life will increase from 24 percent as of 2022 to approximately 30 percent by 2029. Similarly, overhead transformers having reached or exceeded useful life will increase from 14 percent as of 2022 to approximately 25 percent by 2029 and the percentage of overhead switches having reached or exceeded useful life will increase from 40 percent as of 2022 to approximately 68 percent by 2029.

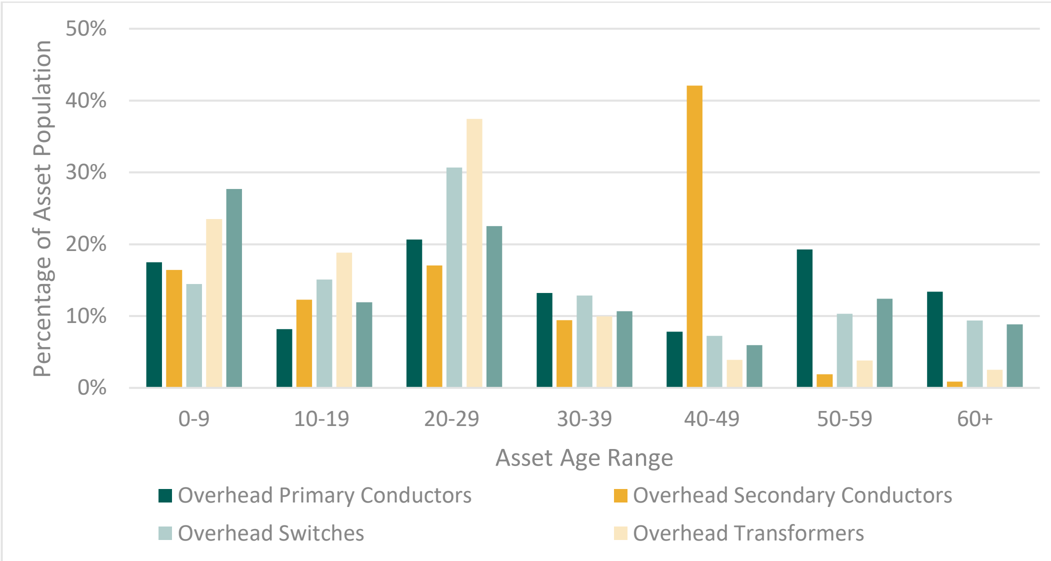

Figure 14: Overhead Assets Age Demographics as of 2022

Wood poles and overhead switches are the two major overhead asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"), as summarized in Figure 10. With respect to wood poles, the ACA showed that approximately 30 percent of Toronto Hydro's wood poles have at least moderate deterioration as of 2022. With over 21,000 wood poles in HI3 condition (i.e. "moderate deterioration"), 8,950 in HI4 condition (i.e. "material deterioration"), and approximately 509 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2029. The need for a continued pole replacement strategy and investment is underscored by the projected rate of deterioration across this asset class over the rate period.[50]

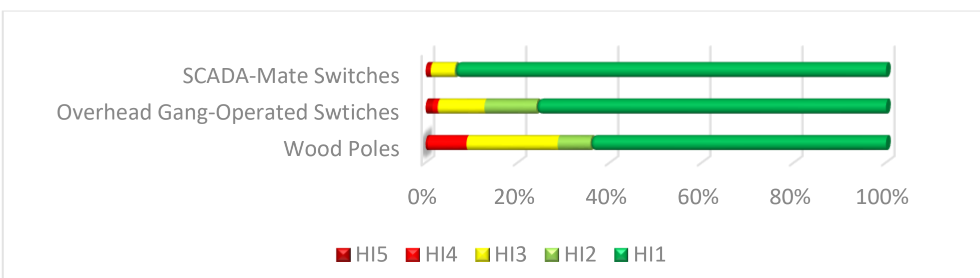

Figure 15: Asset Condition Assessment of Overhead Assets as of 2022

[50] *Supra* note 43.

Other key asset management performance measures that are relevant to the overhead system include:

- **Oil Deficiencies**: Pole top transformers are the only asset type in the overhead system that may exhibit oil deficiencies. During the 2020-2022 period, Toronto Hydro found on average six pole-top transformers with oil deficiencies annually. The Reactive and Corrective Capital program (Section E6.7) will continue to target pole top transformers exhibiting oil deficiencies.
- **Priority Deficiencies:** Overhead assets are susceptible to external interference from animals, insects, adverse weather, and vegetation contacts. These factors accelerate degradation processes and cause damage. From 2019 to 2022, Toronto Hydro issued more than 10,000 work requests to address deficiencies, predominantly for failing or failed overhead assets. In 2022 alone, Toronto Hydro classified 218 P1, 724 P2, and 2,132 P3 priority deficiencies on the overhead system.
- **PCBs**: Pole top transformers are the only asset type in the overhead system that are known to contain PCB contaminated oil. At of the end of 2024, there will be an estimated 500 PCB pole top transformers containing or at risk of containing PCBs remaining on the system. By replacing these assets, predominantly through the Overhead System Renewal program (Section E6.5), Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by the end of 2025.

D2.2.1.1 Overhead Legacy Equipment

On the overhead system, a major challenge facing Toronto Hydro stems from legacy overhead assets such as porcelain insulators and arrestors, non-standard animal guards, and legacy construction types such as rear lot and box construction. These legacy assets contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are planned to target and mitigate challenges within the overhead system include: Area Conversions,[51] Overhead System Renewal,[52] and Reactive and Corrective Capital.[53]

1. Obsolete and deteriorating overhead accessories

Overhead accessories include three major categories: insulator hardware, conductors, and animal guards. These assets are interconnected and integrated with transformers, poles, and switches and are vital components of the distribution system.

- **Legacy Insulator Hardware:** Toronto Hydro's legacy insulators are predominately porcelain, which is an insulation material that has been commonly used for switches, lightning arrestors, terminators, and line posts. The failure modes for assets with porcelain insulating material typically involve assets cracking and breaking apart. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. Porcelain hardware has the potential to fail in a catastrophic manner, releasing porcelain shards which can damage nearby equipment and public property. For example, one porcelain insulator failure incident in Toronto sent shards of porcelain into the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of this porcelain pothead failure can be seen in Figure 16. In general, porcelain material tends to have a high risk of failure due to its tendency for contamination build-up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults), and as such, will be replaced with polymeric material.

[51] Exhibit 2B, Section E6.1.
[52] *Supra* note 43.
[53] *Supra* note 37.

Figure 16: Porcelain Pothead Failure

- **Animal Guards:** Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. Toronto Hydro is installing newer animal guards with a design that provides an improved physical non-conductive barrier. Figure 17 below shows the difference between "Guthrie" and the new animal guards used by Toronto Hydro to guard against wildlife.

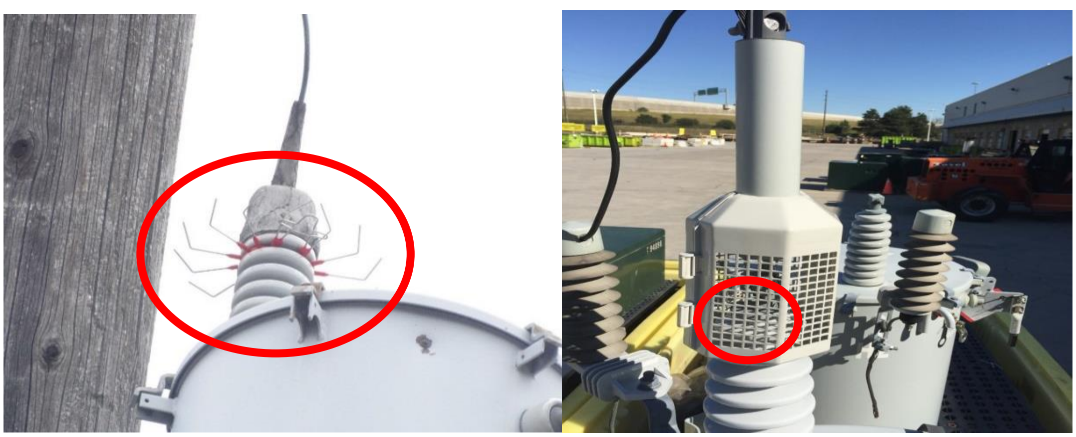

Figure 17: Animal Guards – Guthrie Guard (left), Newer Wildlife Guard (Right)

2. Legacy construction types

- **Rear Lot Construction:** This consists of overhead and underground assets that are installed in the backyard, or rear lot, and are generally operating near or beyond useful life. These assets were installed to serve residential customers in the Horseshoe region of Toronto. Due to accessibility limitations, outages on the rear lot plant tend to be longer in duration. The location of the plant also presents safety risks to customers and employees. Toronto Hydro is continuing to replace rear lot plant with standard, front lot underground circuits as part of the Area Conversions program.[54]

- **Box Construction:** These overhead feeders are located along main streets in the downtown area and serve residential neighborhoods and small commercial customers. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. Toronto Hydro plans to eliminate the remaining box framed poles by 2026 as part of the Area Conversions program (Section E6.1).

D2.2.1.2 Overhead Assets Failure Characteristics

Table 2 below highlights the failure modes and impacts of overhead asset failures.

Table 2: Overhead Asset Failure Modes

Asset	Failure Mode	Effects
Pole Top Transformer	a) Arc flash due to contamination of bushing. b) Corrosion of tank. c) Winding Failure.	a) Causes tracking and can lead to catastrophic failure (e.g. oil fire, spill). b) Causes oil leakage and potential environmental issues. c) Can lead to catastrophic failure (e.g. oil fire, spill).
Wood Poles & Accesssory Equipment	a) Rotted pole (below ground and at ground level). b) Contamination of insulators. c) Pest infestation.	a) Pole and equipment on it could fall causing an outage, safety issues and environmental issues associated with oil leakage. b) Pole can catch fire due to tracking. c) Compromises pole strength; equipment can fall and drop; safety and environmental risks.
Overhead Switches	a) Burnt disconnect contacts due to contamination. b) Corroded or loose connections.	a) Overheating of parts that can lead to malfunction and/or equipment falling. b) Device misoperation or overheating of parts that can lead to malfunction and/or equipment falling.

[54] *Supra* note 49.

D2.2.2 Underground Grid System

The underground system consists of cables, transformers, switches, and civil infrastructure. All of these assets are placed at grade, below grade, or inside building vaults. The underground system eliminates many non-asset risks that are present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding or faster deterioration due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and restoration may take longer because the assets are underground and not visible to crews.

The Horseshoe underground distribution system is operated at 27.6 kV, 13.8 kV, with a subset of the system operating at 4.16 kV. The downtown underground distribution system is operated at 13.8 kV, and 4.16 kV. The main underground configurations are either radial or looped, with radial being the predominant configuration in the downtown system.

System types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution (“URD”). URD is a distribution configuration in parts of the downtown area with primary cables, switches and distribution transformers placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allow sectionalisation (i.e. the ability to use switching to segment a feeder into sections) within the feeder to minimize interruptions when work is required, or to allow partial restoration of the feeder under fault conditions. Figure 18 shows a picture of a typical installation.

Figure 18: Typical Layout of Underground Residential Distribution

Toronto Hydro's underground system consists of approximately 4,000 underground switches, 30,800 underground transformers, 10,300 cable chambers, and 6,100 circuit-kilometres of underground primary and 6,800 circuit-kilometres of underground secondary cables.

Asset management activities related to the underground distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 19 provides the age demographic distribution of major underground assets. The age of XLPE cables represents a significant risk to reliability in the 2025-2029 rate period and must be prioritized.[55] Moreover, as of 2022, over 20 percent of underground transformers are approaching their useful life of 30 years, over 20 percent of cable chambers are approaching their useful life of 65 years and approximately 80 percent of cable chamber roofs are at or approaching their useful life of 25 years. Without proactive intervention, Toronto Hydro projects that the percentage of

[55] Exhibit 2B, Section 6.2.

underground assets having reached or exceeded useful life will increase from approximately 20 percent to 40 percent by 2029 for underground transformers, from 20 percent to 31 percent by 2029 for cable chambers, from 80 percent to 87 percent for cable chamber roofs.

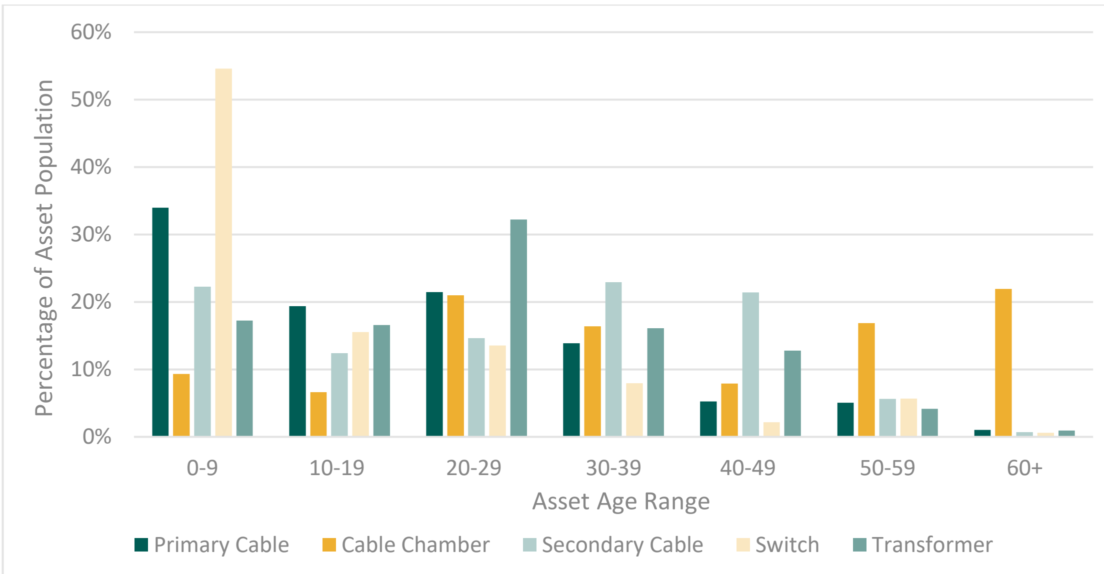

Figure 19: Underground Assets Age Demographic as of 2022

Underground switches, underground transformers and cable chambers are major underground asset classes for which Toronto Hydro performs an ACA. As shown in Figure 20, approximately 9 percent of Toronto Hydro's underground switches, 7 percent of underground transformers and 25 percent of cable chambers have at least moderate deterioration (i.e. HI3, HI4, and HI5) as of 2022. With over 2,000 cable chambers in HI3 condition, over 450 in HI4 condition, and 130 in HI5 condition (i.e. "end of serviceable life"), cable chamber replacement will continue to be a significant driver of both reactive and planned investment through 2029.

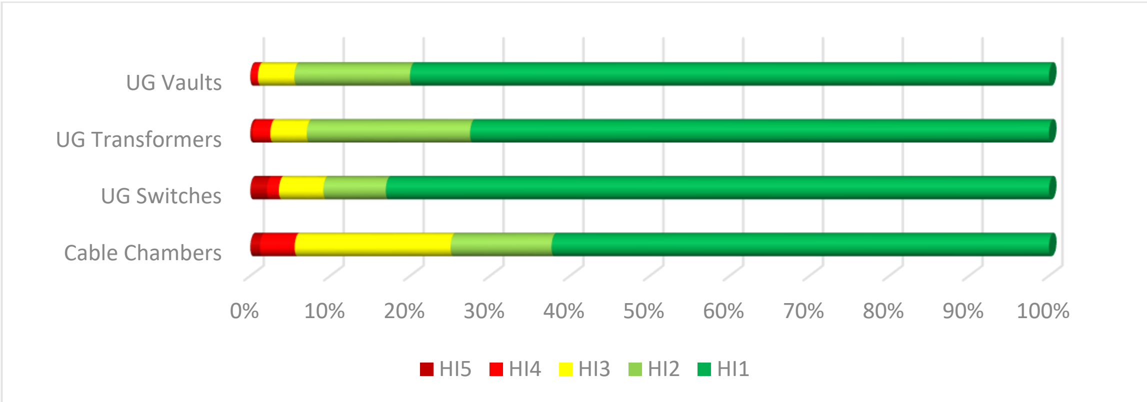

Figure 20: Asset Condition Assessment of Underground Assets as of 2022

Other key asset management performance measures that are relevant to the underground system include:

- **Oil Deficiencies:** Between 2020 to 2022, Toronto Hydro found, on average, 420 underground transformers with oil deficiencies per year. Assets replaced in the Underground System Renewal programs and Reactive Capital program will include assets exhibiting oil deficiencies found during inspections.

- **Priority Deficiencies:** The underground distribution system includes many below-grade vaults and cable chambers. The assets housed within them include cables, splices, joints, ducts, vents, hatchways, sump pumps, transformers, and switches. From 2019 to 2022, Toronto Hydro issued more than 25,000 work requests to address failing or failed underground assets. In 2022 alone, Toronto Hydro identified 496 P1, 1,677 P2, and 6,782 P3 priority deficiencies on the underground system.

- **PCBs:** Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, and network), which can potentially contain PCB contaminated oil. Toronto Hydro plans to continue the replacement of the remaining underground transformers that are known to contain, or are at risk of containing, PCB-contaminated oil, by 2025, predominantly through the Underground System Renewal programs (Section E6.2 and E6.3). If sub-standard conditions are found during inspections, replacements may be done through the Reactive and Corrective Capital program as well.

D2.2.2.1 Underground Legacy Equipment

1. Direct-Buried XLPE Cable

Cables are the single greatest contributor to defective equipment caused outages on Toronto Hydro's system, contributing on average 146,000 CHIs annually from 2013 to 2022. The underground system in the Horseshoe area consists of 666 circuit-kilometres that are direct-buried cable and direct-buried cable in duct, of which 286 circuit-kilometres are direct-buried XLPE cable. Approximately 73 percent of direct-buried cable has reached or is past its useful life as of 2022. Toronto Hydro has already begun to see deterioration in underground system reliability performance in recent years, and the utility expects that a failure to proactively address this aging asset group will have worsening impacts on outages caused by defective equipment failures.

These cables are susceptible to outages due to direct exposure to environmental conditions. "Water treeing" is the most significant degradation process for XLPE cable, and starts with moisture penetration into the cable insulation in the presence of an electric field. These "trees" are microscopic tears within the dielectric. Over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to migrate into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of water treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation. Figure 21 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 22 illustrates field and laboratory samples of microscopic voids bubbles) and damage to the insulation.

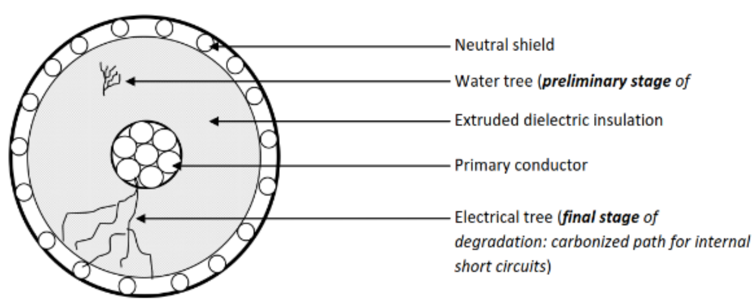

Figure 21: Cable Failure due to Electrical Treeing

Figure 22: Field and Laboratory Sample of Microscopic Voids and Damage XLPE Insulation

There is an immediate need to address the issues associated with direct-buried XLPE type cables so as to maintain system reliability for current and future customers in the Horseshoe area of Toronto. For further information, please see the Underground System Renewal – Horseshoe Program.[56]

2. Underground Lead Cable (PILC and AILC)

The majority of the cable in Toronto Hydro's downtown underground system is of two types: Paper-Insulated Lead-Covered ("PILC") and Asbestos-Insulated Lead-Covered ("AILC"). These cables are typically found at busy intersections beneath the sidewalks and roads of Toronto's downtown core. PILC cables are used as 13.8 kV primary cables, while AILC cables are used as secondary cables rated at 600 V. AILC cable is typically found on the secondary network 120/208 V and 240/416 V systems. Approximately 51 percent or 985 circuit-kilometres of Toronto Hydro's downtown primary system consists of PILC cable, whereas 49 percent or 176 circuit-kilometres of all secondary cable in the downtown network system consists of AILC cable.

Historically, utilities installed lead cable to take advantage of its reliability and compact design. However, over time, many utilities encountered environmental and health and safety issues with these cables. The industry has moved away from using these cables and for a number of years, there has been only one supplier remaining in the market for PILC (with none for AILC). Due to the supply risk (and the aforementioned environmental and safety risks), Toronto Hydro has avoided installing new lead cable for a number of years. Other utilities have taken a similar approach. As time passes,

[56] *Ibid.*

the number of individuals in the industry with the expert skillset required to work on lead cable in the field continues to diminish. Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Toronto Hydro is continuing its proactive replacement of lead cables and plans to remove approximately 5.3 percent of 176 km AILC cable and 3.5 percent of 985 km PILC cable between 2025 to 2029. This is discussed further in the Cable Renewal segment of the Underground System Renewal – Downtown program.[57]

D2.2.2.2 Underground Assets Failure Characteristics

Table 3 provides a brief overview of the failure modes and impacts of underground asset failures.

Table 3: Underground Asset Failure Modes

Asset	Failure Mode	Effects
Underground Cable	a) Insulation degradation (eg. water trees). b) Carbon tracking in PILC cable paper insulation due to absence of oil medium (oil leak). c) Degradation due to age (cracked or degraded jacket).	a) Insulation breakdown and electrical fault. b) Impregnating oil dries up, cable overheats, degrading the insulation. c) Water ingress, corrosion of the metallic shield, penetration into the insulation (potentially causing water trees).
Submersible Transformers	a) Oil Leak. b) Corrosion of tank. c) Gasket deterioration due to age. d) Corroded secondary terminations (compression or bolted lugs).	a) Transformer cooling and insulating properties are diminished, electrical fault may occur. b) Oil leaks, transformer cooling and insulating properties are diminished; may result in internal components damage and electrical fault. c) Oil leaks, ingress of moisture may occur, transformer cooling and insulating properties are diminished. d) This failure mode can arise due to a flooding or contamination. Results in the secondary termination failure.

[57] Exhibit 2B, Section E6.3.

Asset	Failure Mode	Effects
Padmounted Transformers	a) Corroded enclosure. b) Enclosure has been exposed to moisture (ground water, moisture ingress). c) Contaminated or damaged insulating barriers. d) Degradation due to age/contamination. e) Gasket deterioration with age.	a) Public or animal access to the transformer. Transformer could be damaged or cause injury to the public. b) Improper ventilation, inadequate air flow, tracking, and flashover. Safety risks heighten as the transformer is located next to sidewalks. c) Tracking on the insulators, and eventual flashover. d) Insulation breakdown and electrical fault. e) Small traces of oil leaking. Ingress of moisture may occur; transformer cooling and insulating properties are diminished.
Underground Switches (Padmounted)	a) Loss of insulating properties due to contamination, moisture ingress, or humidity. b) Switch has been exposed to moisture (ground water, moisture ingress.	a) Flashover - presents a safety concern as the switch is located next to sidewalks. b) Improper ventilation and inadequate air flow create tracking and possible flashover and failure, presenting a safety concern as the switch is located next to sidewalks.
Cable Chambers	a) Collapsed duct. b) Excessive water leakage through ducts. c) Structural degradation at the neck. d) Cable racks and arms rust and deterioration. e) Cracks, spalling, delamination of concrete in walls or roof; corrosion in rebars.	a) Hotspot depending on the extent of damage, cable damage. Worst case can involve damage to connected equipment, posing a safety risk to the public. b) Degradation of walls, floor, corrosion to the racks. c) Access is restricted. If chamber is on roadway, a sinkhole may occur, posing a safety risk. d) Racks fall off the wall causing the cable or joint to be unsupported and possibly cause damage to other cables, posing a potential safety risk. e) Chunks of concrete falling down, structural collapse, wall or roof failure, and/or fire, posing a safety risk.

D2.2.3 Secondary Network System

The secondary network (or "network") system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads. As the system evolved, it became recognized for its ability to efficiently serve medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have sufficient space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in a grid (also known as mesh) configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical overhead and underground distribution systems do not. Should a single primary feeder experience an outage, network connected customers will continue to be supplied from alternate primary circuits that continue to feed into the secondary grid. In this way, the secondary network system offers greater reliability than other underground or overhead systems.

At the heart of the network system are network units. The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip (i.e. open the switch to interrupt the current backfeeding into the fault). This protects the primary feeders from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though the network system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the entire secondary network grid that is connected to the vault must be interrupted to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. To avoid these scenarios, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons why Toronto Hydro takes a proactive approach to the maintenance and replacement of network units at risk of failure. Figure 23 below shows a typical submersible network unit.

Figure 23: Submersible Network Unit

The vaults that house network equipment are also an important component of the network system and must be maintained. If the integrity of a vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for employees. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. Moreover, cracking and structural shifting of vault roof structures pose trip and fall hazards, and complete failure of roof elements can expose the public to energized electrical equipment. As of 2022, approximately 5.5 percent of network vaults and approximately 75 percent of network vault roofs past their useful life.

Figure 24 provides the age demographic distribution of major network assets. As of 2022, approximately 21 percent of network units and approximately 6 percent of network vaults are at or approaching their useful life of 35 years and 60 years, respectively. Without intervention, Toronto Hydro projects that the percentage of network units having reached or exceeded useful life will increase from 21 percent to 27 percent, and the percentage of network vaults will balloon from 6 percent to 26 percent by 2029. Non-submersible network units are one asset type that Toronto Hydro plans to target specifically. These units are susceptible to water ingress and elevated failure risks even when in good condition. As such, they need to be replaced to reduce the failure risks on the network system. Replacements will occur on a prioritized basis considering factors such as condition, as discussed in Network System Renewal program.[58]

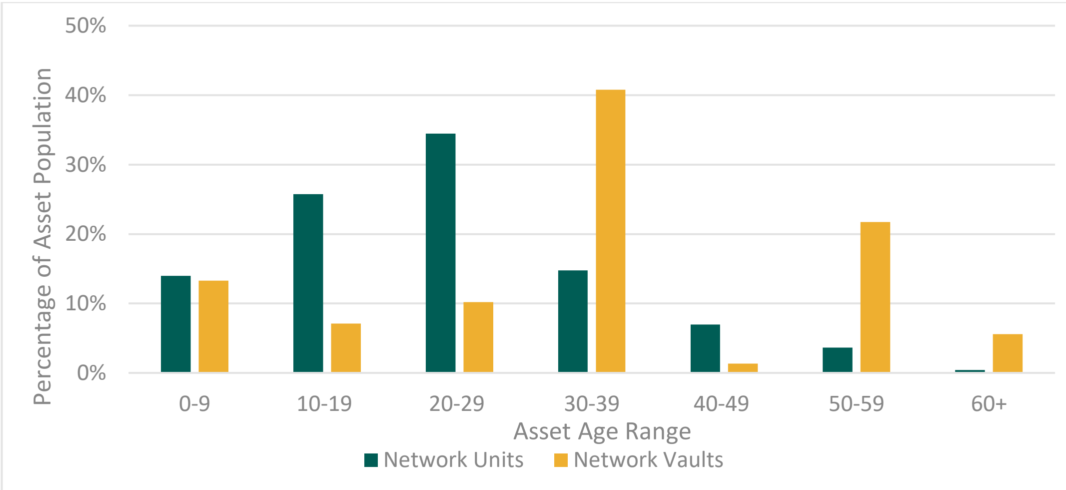

Figure 24: Network Assets Age Demographics as of 2022

Toronto Hydro performs an ACA for network transformers, network protectors, and network vault civil infrastructure. ACA results show that approximately 6 percent of network transformers, 29 percent of Toronto Hydro's network vaults and 15 percent of network protectors have at least moderate deterioration as of 2022.

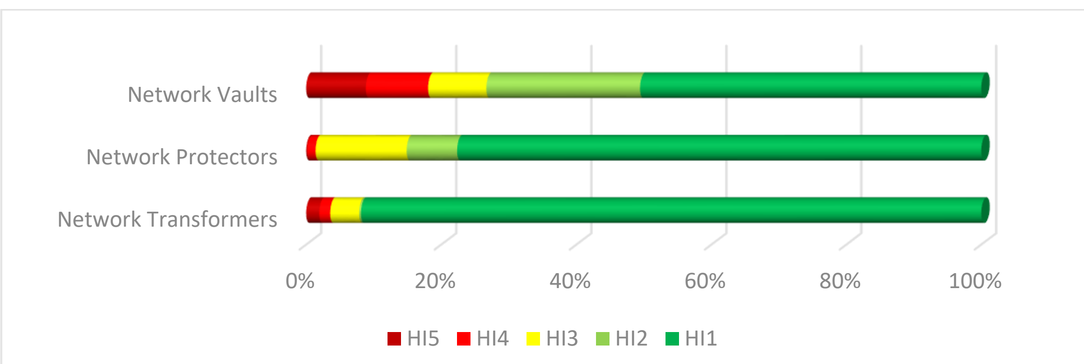

Figure 25: Asset Condition Assessment of Secondary Network Assets

Asset management activities related to the network focus on asset stewardship over asset life spans, mitigating environmental and safety risks, responding to system events and equipment deficiencies,

[58] Exhibit 2B, Section E6.4.

and managing system performance with respect to reliability and power quality. The following summarizes what this means relative to the measures set out in Table 2:

- **Oil Deficiencies**: Network transformers are the only asset group in the network system affected by this outcome. During the 2020-2022 period, Toronto Hydro found on average 47 oil deficiencies per year for network transformers. Assets replaced in the Network System Renewal Program and Reactive Capital Program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Please see the discussion related to priority deficiencies under section D2.2.2 above as deficiencies related to the secondary network are generally tracked with all other underground deficiencies.

D2.2.3.1 Network Legacy Equipment

During the 2020-2024 rate period, Toronto Hydro has removed network legacy equipment, such as Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"). Toronto Hydro continues to replace non-submersible network protectors as part of Network System Renewal program,[59] through 2029.

1. Eliminating Network Units with Non-Submersible Protectors

Although network units are replaced based on condition, another consideration that informs investment decisions is the presence of "non-submersible" designs which are characterized by ventilated or semi-dust-tight protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. The failure modes for network units are flooding and internal transformer failure. Flooding can damage the protector mechanism, causing the unit to short, or fail to operate, whereas transformer failure can result from overloading, low oil, moisture ingress, or age-related insulation deterioration. Toronto Hydro is continuing to replace non-submersible protectors with submersible protectors that feature watertight cases to help address flooding risks as part of the Network System Renewal program.[60] Figure 26 below shows the difference between a ventilated network unit and a submersible network unit, where the black protector identified is of a submersible design.

[59] *Ibid*.
[60] *Ibid*.

Figure 26: A ventilated Network Unit (Left) and a Submersible Network Unit (Right)

D2.2.3.2 Network Assets Failure Characteristics

Low voltage secondary distribution networks are susceptible to similar failure modes as other underground distribution systems; however, the consequences of failure to operate and network customer service reliability are often different, as outlined in Table 4 below.

Table 4: Network Asset Failure Modes

Asset	Failure Mode	Effects
Underground Primary Cable	a) Insulation degradation. b) Jacket damage. c) Mechanical stresses compromising geometry of cable. d) Multiple primary cable outages occur simultaneously.	a) Internal arc occurs; station circuit breaker trips causing feeder outage. b) Internal arc occurs; Network vaults continue to operate under contingency, with possible equipment overloads. c) Internal arc occurs; dual radial customers supplied by faulted feeder are interrupted until switched to alternate feeder. d) Equipment overloads may force the Control Room to drop the entire network, resulting in widespread customer interruptions.

Asset	Failure Mode	Effects
Underground Secondary Cable	a) Insulation degradation. b) Failed cable conductor contacts another conductor. c) Self-cleared secondary cable faults are not identified.	a) Arcing fault occurs. b) “Solid” fault occurs and may spread to adjacent cable junctions before self-clearing, resulting in interruptions to a small number of customers. c) Surrounding secondary cables may overload and eventually fault, resulting in interruptions to multiple customers.
Network Transformer	a) Insulation degradation due to age/contamination. b) Low or no oil level. c) Corrosion of the steel tank or gasket failure. d) Electric interlock stuck open and fails to prevent movement of the primary switch handle while transformer secondary is energized.	a) Internal insulation failure leading to an increased likelihood of catastrophics transformer failure due to the fact that the insulation characteristics are lost. b) Insulation fails to provide dielectric and mechanical insulation to the windings and may lead to major internal electrical fault in transformer or primary switch. c) Results in insulating oil leakage, which may cause contamination of the surrounding environment. d) Operator can move the handle without interference on an energized feeder; possibility of fatality.
Network Protector	a) Debris, salt, and moisture collect on the top of a network protector. b) Vault flooding allows water to enter the protector. c) Breaker mechanism gummed up, seized or broken. d) Motor fails (all possible causes), broken springs, broken close mechanism or motor fuse blown.	a) Causes an electrical short in protectors which typically result in vault fires, with the possible destruction of all electrical equipment in the vault. b) The mechanism fails and possibility of an electrical short; may result in permanent damage to the mechanism. c) Circuit breaker fails to close when instructed by relay. Motor fuse blows or motor may burn out, and excessive wears of moving parts. d) Motor assembly fails to provide mechanical force to charge springs that trip the circuit breaker open; moderate localized damage.

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. ("Hydro One") at voltages of 230 kV, 115 kV at Transformer Stations ("TS"). In general, Toronto Hydro owns all of the medium voltage equipment up to the circuit breaker at a TS, subject to certain differences in ownership structures for each TS's equipment. Figure 27 below shows the ownership of station equipment and their associated demarcation point. In some areas, the voltage may be further stepped down to 13.8 kV or 4.16 kV at Municipal Stations ("MS") which are wholly-owned by Toronto Hydro.

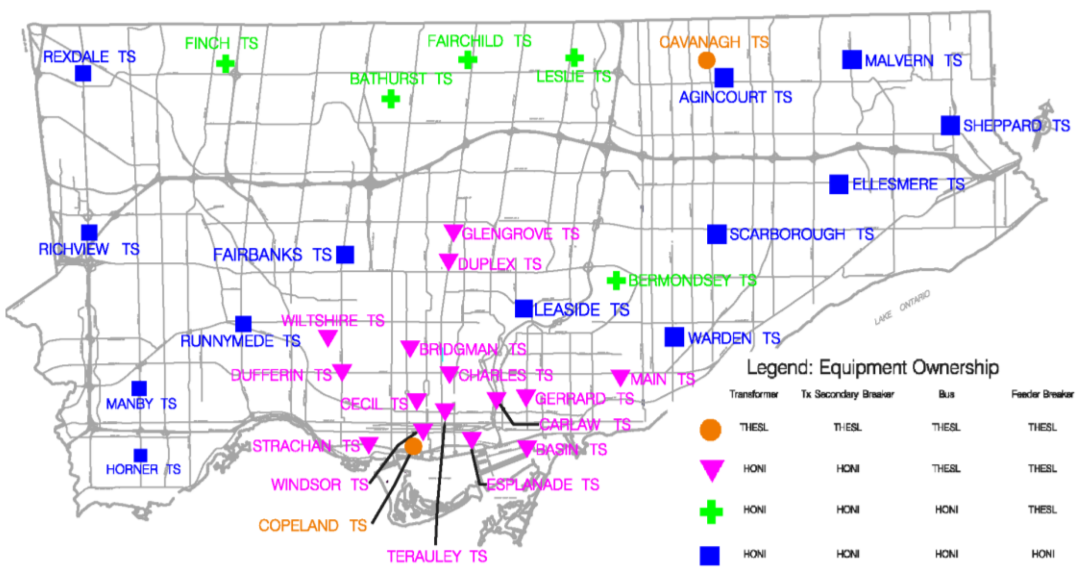

Figure 27: System Diagram of Station Components Ownership

Toronto Hydro is supplied by 37 TSs, including Copeland TS (as shown in Figure 27 above), and owns approximately 139 MSs. Within these stations, Toronto Hydro owns and operates approximately 200 switchgear, 175 power transformers, 40 outdoor circuit breakers, 80 remote terminal units ("RTUs"), and 170 direct-current ("DC") battery systems.

Feeders generally have at least one normally-open tie to another feeder to ensure there is a restoration option in case of an outage, or if planned work is required.[61] In the Horseshoe area, there are typically many normally open ties between feeders fed from the same bus or feeders fed from a

[61] Secondary network systems and pilot-wire/line-differential based systems operate with multiple supply points in parallel and do not require a normally open tie.

different bus or station. This allows for increased operational flexibility and the ability to restore some load in the event of a bus or station outage. Feeders in the downtown area rely on a radial configuration with normally open ties to feeders supplied from the same bus, but never have ties with feeders fed from other stations. This configuration limits the restoration options for these feeders in case of a station outage. Toronto Hydro does look for opportunities to build contingency ties between different downtown stations where economical. For example, Toronto Hydro invested $5.5 million to install interstation switchgear ties between Copeland TS and Windsor TS between 2020-2022. The Copeland to Windsor ties served three purposes: contingency support to prevent extended power outage in the downtown core, provide facilities to offload Windsor station switchgear to enable switchgear upgrade projects, and implement long-term downtown contingency ties between these two stations.

Asset management activities related to stations focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies when they are identified, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' life span.

Figure 28 provides the age demographic distribution of major station assets. Toronto Hydro's critical stations asset base is of an increasingly advanced age on average. As of 2022, 42 percent of Toronto Hydro's switchgear, 51 percent of power transformers, 42 percent of outdoor breakers, and 55 percent of DC battery systems are operating at or beyond their useful life. Without proactive intervention, the proportion of station assets operating beyond their useful life will continue to increase, contributing to already elevated asset failure risks for highly critical assets. Station asset renewal is complex and entails considerable operational constraints which limit the achievable level of renewal in a given year. Consistent investment and renewal work is needed to sustainably mitigate and control the failure risk presented by these assets.

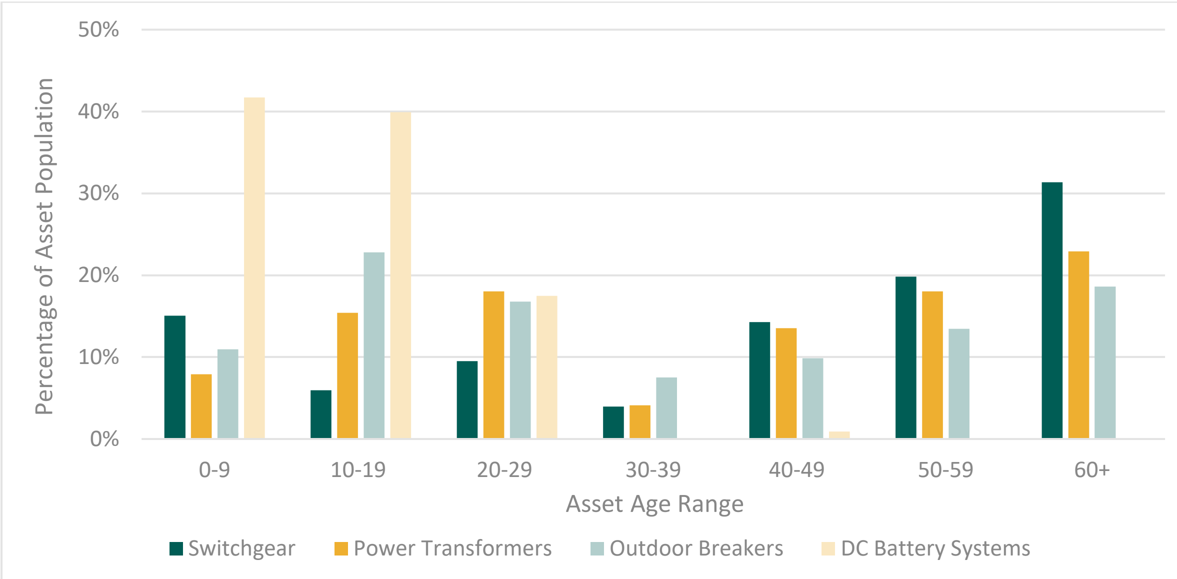

Figure 28: Stations Assets Demographics as of 2022

Within its stations asset classes, Toronto Hydro performs ACA analysis on its power transformers as well as various types of its circuit breakers. With the exception of standalone outdoor circuit breakers, circuit breakers are contained inside one of Toronto Hydro's switchgear and are considered components of their parent switchgear. Therefore, ACA performed on breakers helps serve as a proxy for switchgear condition.

Figure 29 shows that 98 percent of Toronto Hydro's air-blast circuit breakers, 93 percent of its oil circuit breakers, 39 percent of KSO oil circuit breakers, 12 percent of station power transformers, 78 percent of air-magnetic circuit breakers, 5 percent of SF_6 circuit breakers, and 1 percent of vacuum circuit breakers show signs of at least moderate deterioration. Accordingly, renewal of switchgear containing air-blast circuit breakers and oil circuit breakers are heavily targeted in the Stations Renewal Program.[62] Similarly, standalone outdoor KSO circuit breakers are prioritized for renewal in the proposed program.

[62] *Supra* note 46.

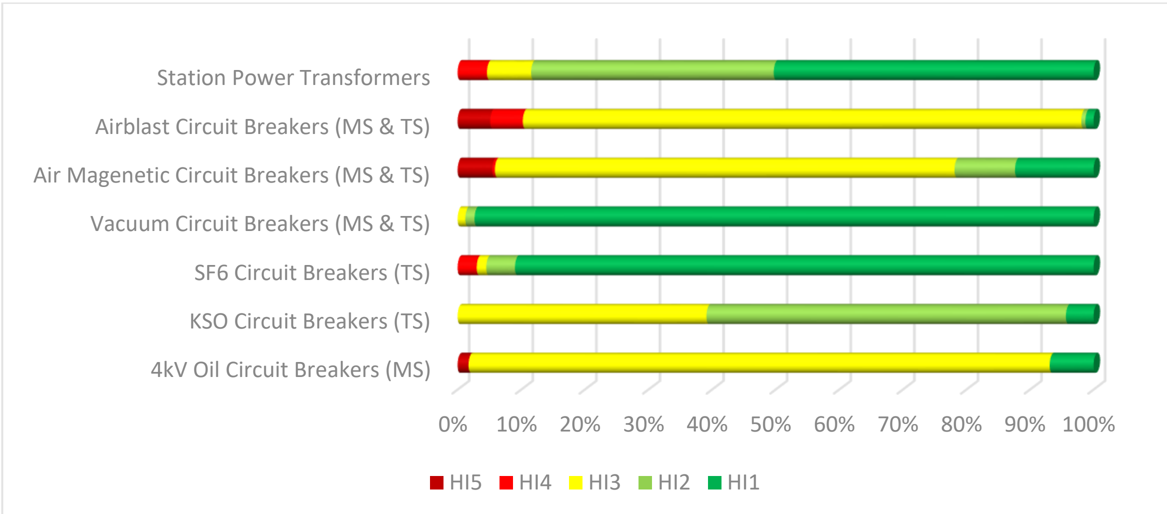

Figure 29: Asset Condition Assessment of Station Assets

Other key asset management performance measures that are relevant to the stations include:

- **Oil Deficiencies**: During the 2020-2022 period, Toronto Hydro found on average 12 station transformers with oil deficiencies per year. Assets replaced in the Station Renewal program,[63] and Reactive and Corrective Capital program will include assets exhibiting oil deficiencies found during inspections.[64]

- **Priority Deficiencies**: Station assets include power transformers, circuit breakers, switchgear, SCADA systems, relays, batteries and chargers, SCADA telemetry or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 141 MSs and 37 TSs. From 2019 to 2022, Toronto Hydro issued more than 2,300 work requests to address failing or failed station assets.

D2.2.4.1 Stations Legacy Equipment

Toronto Hydro has many legacy station assets currently in operation, which are being phased out through capital renewal plans, as discussed in the Stations Renewal Program.[65]Legacy assets include: (i) non-arc-resistant brick and metalclad switchgear; (ii) air-blast, oil, KSO oil, and air magnetic circuit

[63] *Ibid*.
[64] *Supra* note 37.
[65] *Supra* note 46.

breakers; (iii) DACSCAN MDO-11, D20 ME, D20M++, and MOSCAD RTUs; electromechanical pilot-wire relays; and (iv) copper communications cable.

Oil and KSO oil circuit breakers are legacy assets which also present several risks including a safety risk to Toronto Hydro personnel, risk of collateral damage to adjacent station equipment, and in some cases a safety risk to the public or an environmental risk. Both oil and KSO oil circuit breakers contain oil, which may catch fire or even explode upon failure of the asset. KSO oil circuit breakers can also contain PCBs. By the end of 2029, Toronto Hydro plans to replace all remaining oil KSO circuit breakers with vacuum type breakers.

D2.2.4.2 Stations Major Assets Failure Characteristics

Table 5 below provides a brief overview of the failure modes and impacts of station asset failures. Typically, failure of these assets results in power outages to all customers supplied by the affected station bus, or even the entire station. In addition to power outages, station asset failures can lead to extensive and irreparable damage.

Table 5: Station Assets Failure Modes

Asset	Failure Mode	Effects
Switchgear	a) Control Cable lose connection due to breaker operation, auxillary socket broken or auxillary socket misalignment. b) Broken/cracked interphase barrier or insulators; dirt or debris on insulators. c) Total cable failure (all possible causes). d) Dirt or debris on busbar conductors.	a) Inability to monitor and operate the breaker via protection and control, and May result in an arc flash. b) Possible flashover, and safety issue involved with the failure due to the explosion if protection fails. c) Loss of power due to relay protection sensing the cable fault and tripping the breaker. d) May lead to overheating and melting of the busbar; flashovers might take out the whole bus and result in a major station shutdown.

Asset	Failure Mode	Effects
Power Transformer	a) Defective bushing gasket (Oil filled bushing). b) Paper insulation failure. c) Defective breather (all possible causes). d) Control circuit or motor failure of onload tap changer.	a) Oil leaks from the bushing may lead to loss of insulation, a short-circuit and eventually an outage. b) Power outage to entire station due to low or fluctuating voltage, or internal fault. c) Moisture enters through breather; moisture ingress will decrease insulation value of oil, eventually causing dielectric breakdown of oil. Flashover may occur. d) Failure to adjust output voltages to desired secondary voltages.
KSO Circuit Breaker	a) Worn latching mechanism or broken lifting rod. b) Breaker fails to open on a fault, no internal arcing occurs. c) Bushing failure causes flashover. d) Oil fails to insulate the live parts within the tank and also extinguishing the arc.	a) Operating mechanism fails to facilitate sequential movement of components to close the breaker; customers will be without power until transferred to alternate supply. b) Power outage to entire station switchgear. c) Power outage to entire station switchgear; flashover damages breaker. d) Breaker opens, but arc remains causing equipment damage and loss of bus. Breaker may rupture causing injury to workers in the vicinity, releasing fumes and oil into the environment and may cause damage to adjacent equipment.
DC Battery System	a) DC charger system fails. b) DC battery fails.	a) All station protection and control capability is lost after 8 hours when the battery has depleted. Station is then rendered inoperable. b) Station is noncompliant with Section 10.7.1 of the Transmission System Code. Should either the DC charger system or station service supply be out of service, then the station is rendered inoperable.

D2.2.5 Metering

Toronto Hydro utilizes several different meter types in order to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. These include: (i) Residential, Small Commercial and Industrial; (ii) Interval; (iii) Suite Metering; and (iv) Wholesale.

- **Residential/Small Commercial & Industrial**: Toronto Hydro must continually upgrade its residential metering system to ensure that it continues to receive vendor support and is capable of enabling features on newer generation meters. The bulk of residential and small commercial and industrial meters have seals expiring between 2024 and 2026. As part of its AMI 2.0 initiative, Toronto Hydro plans to replace residential and small commercial and industrial meters with next generation meters.[66]

- **Interval**: Toronto Hydro plans to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE") to continue to successfully meter Toronto Hydro's interval metered customers (those with a demand of 50 kW or above). The upgrade is scheduled for completion by 2025. In 2017, Toronto Hydro had 7,000 Interval metered customers on IEE. In 2020, this increased to 14,000 customers due to the decommissioning of the 2G network in Toronto, and the subsequent conversion by Toronto Hydro of its 2G meters to newer 4G technology. By the end of 2022, Toronto Hydro's interval metered customers reached 17,000 customers due to conversion of various customer groups from manual reads and manual billing.

- **Suite Metering**: These meters represent the individually metered multi-residential buildings. The utility is legally obligated to provide suite meter installation services. Toronto Hydro offers this service in a competitive environment, and is also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider. Currently, there are approximately 94,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter. Toronto Hydro plans to continue to offer its suite metering services to new customers along with retrofit upgrades over the 2025-2029 rate period.

- **Wholesale**: Toronto Hydro plans to upgrade its wholesale revenue meters at all applicable wholesale metering points to comply with the metering standards mandated by the

[66] Exhibit 2B, Section E5.4.

Independent Electric System Operator ("IESO") Market Rules and Measurement Canada during the 2025-2029 period. These meters are installed at each of Toronto Hydro's transfer stations, and are used by Toronto Hydro to purchase power and to validate consumption with the IESO.

Toronto Hydro must maintain its fleet of meters in order to comply with both Measurement Canada and OEB mandates such as billing accuracy, estimated bills, and meter seals. In this regard, Toronto Hydro re-seals batches of meters to ensure accuracy and reactively replaces failed or non-communicating meters to ensure compliance. Toronto Hydro's meter population is aging with the majority of the residential and small C&I meter population reaching and exceeding 15 years of age during the 2025-2029 rate period. By 2025, approximately 90 percent of Toronto Hydro's residential and small commercial meters will surpass their useful life. To address this risk of failure, Toronto Hydro intends to replace its full population of first-generation residential and small C&I meters with next generation meters and supporting network infrastructure.

D2.2.5.1 Metering Major Assets Failure Characteristics

Table 6 below provides a brief overview of the failure modes and impacts of metering asset failures.

Table 6: Metering assets failure mode

Asset	Failure Mode	Effects
Energy Meter	a) Communications Failure	a) Bills must be estimated or meter manualy read
Instrument Transformer	b) Device Failure	b) Meter reads would be incorrect due to failed instrument transformers

D2.3 System Utilization

Toronto Hydro completes an annual System Peak Demand Forecast for station bus capacity to plan for short- and long-term load growth, additional capacity requirements to serve customers, and contingency scenarios such as planned work or loss of supply. This peak demand forecasting process is further explained in Section D4.1.1 and Section D3.3.1.1. To prevent system overloading which may lead to asset failures, the peak utilization of a bus should not reach or exceed 100 percent of its rated capacity for extended periods of time.[67] Bus capacity rating is determined based on the ratings for all of its associated equipment and a Limited Time Rating for upstream equipment provided by Hydro One. [68] Forecasting is performed at the bus level.

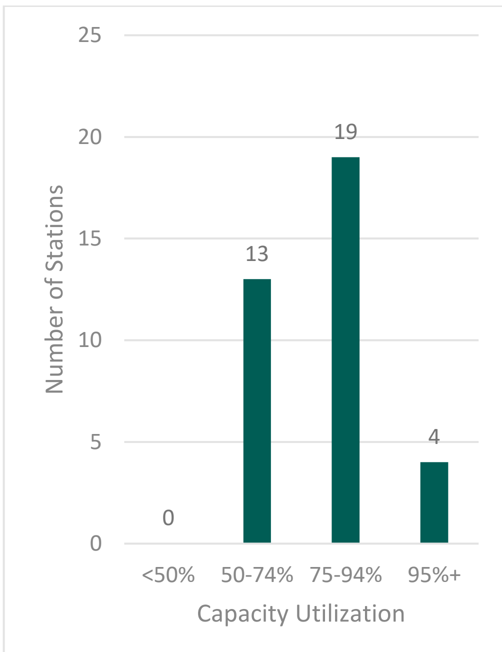

Figure 30: Forecasted Station Loading in 2025

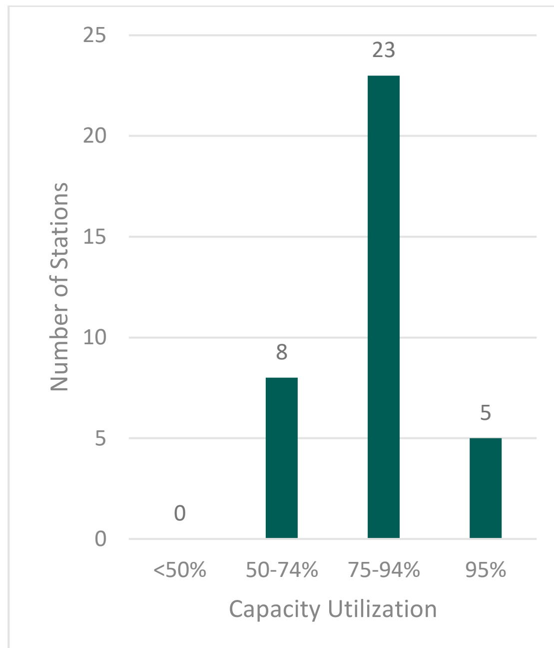

Figure 31: Forecasted Station Loading in 2030

From a station capacity standpoint, by 2025, 64 percent of Toronto Hydro stations will experience loading of 75 percent or higher, with four stations that are forecasted to be near capacity. By 2030, Toronto Hydro anticipates that the aforementioned percentage will increase to 78 percent, with five stations expected to exceed their capacity. Operating stations at 100 percent capacity would severely

[67] For planning purposes, a 95 percent loading threshold is used for the downtown region, while a 100 percent bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in Section D3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

[68] Limited Time Rating ("LTR"): With respect to transformers, a limited time rating is a set of 15-minute, 2-hour, and 10-day MVA ratings determined by Hydro One in order to accommodate shorter time interval loading periods without causing equipment damage. All of Toronto Hydro's buses are supplied via at minimum two transformers operating in parallel. For bus capacity planning purposes, Toronto Hydro utilizes the 10-day LTR rating provided by Hydro One which is the maximum MVA the most limiting transformer can supply for a 10-day period with the other transformer out-of-service.

limit the utility's flexibility to manage abnormal system states (planned or unplanned). In a worst-case scenario, Toronto Hydro would be unable to maintain or replace a failing or failed asset.

More specifically, Toronto Hydro must also ensure that each of its stations has sufficient capacity to connect new or existing customers without sacrificing system reliability or operational flexibility for existing customers. Otherwise, extensive load transfers must be pursued through the Load Demand Program solely to free up the capacity needed to connect new customers without overloading a bus. Although this limit precedes station capacity, it is the primary driver for the need for extensive load transfers or station expansion projects so that new customer connections can be made.

To mitigate overloading at the stations and free up capacity to connect new large customers, Toronto Hydro analyzes each station's load forecast as well as available capacity in the area to resolve loading problems. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station. A large number of limitations and considerations must be considered in implementing these solutions, including:

- incompatible system voltages (e.g. 27.6 kV vs. 13.8 kV);
- incompatible system types (e.g. radial versus looped, or overhead versus network);
- availability of civil infrastructure;
- availability of feeder positions;
- environmental or civil barriers (e.g. rivers, highways ravines); and
- relative cost between relief options.

Due to these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, Toronto Hydro typically plans new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging. Similar limitations and considerations at both the feeder level and station level must be accounted for in the planning process. This process is largely reactive given the significant uncertainty in forecasting feeder loading, because it is difficult to predict exactly where new loads will materialize and there are multiple feeders which can potentially connect new loads.

On the asset level, Toronto Hydro frequently reviews the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized. Nonetheless, Toronto

Hydro has initiatives in place which will install new infrastructure and allow more assets to be closely monitored. Examples of such initiatives are network monitoring, stations control and monitoring replacements and new installations, and power transformer and switchgear replacements. These initiatives help prevent overloading which may cause premature equipment failure.

Stantec

CLIMATE CHANGE VULNERABILITY ASSESSMENT UPDATE

November 18, 2022

Prepared for:
Toronto Hydro-Electric System Limited

Prepared by:
Stantec

Project Number:
160925171

The conclusions in the Report titled Climate Change Vulnerability Assessment Update are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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Executive Summary

This Climate Change Vulnerability Assessment Update was conducted by Stantec to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The main objective was to identify if any further work is required to update the adaptation actions recommended in the 2015 Study. The study uses updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), released along with the IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. The two main tasks completed were to (1) update climate parameter probabilities and scores using CMIP6 data and scientific literature published since the 2015 Study; and (2) assess the materiality of the probability updates, by re-calculating the risk scores over the study period (from 2022 to 2050) following the PIEVC Protocol version 10 (Engineers Canada, 2011). Wherever possible, the same methods used in the 2015 Study were also used in this assessment.

To estimate the climate parameter probabilities, the complete ensemble of climate model outputs from the downscaled CanDCS-U6 dataset were used, and review of scientific literature, including the *Climate-Resilient Buildings and Core Public Infrastructure 2020* (Cannon et al., 2020) report was completed. A summary of the probability updates that resulted in a change to the probability scores is provided in the table below.

Climate Parameter	**Threshold**	**Frequency** (2030s)	**Probability** (Study Period)	**Probability Score** (Study Period)	**Probability Score Change** (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The only climate parameters whose probability scores changed were 'days with maximum temperatures >40°C', and 'ice storms with >25mm of ice accretion', both of which decreased by 1. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures >40°C and 13 from Ice Storms >25mm), as summarized in the table below.

Climate Parameter	**Threshold**	**Study Report Year**	**Number of Interactions by Risk Class**		
			High	**Medium**	**Low**
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

While the results show a slight decrease to the risk scores for these 23 interactions, the uncertainty in the climate projection data is high, therefore it is not recommended to relax the adaptation measures associated with extreme heat or freezing rain events from the 2015 Study.

Despite no change to the assigned probability scores, the annual frequency of high daily average temperatures >30°C (increase), heat waves (increase), and high nighttime temperatures (decrease) are all expected to change by >10% in the 2030s. The change is not material based on the approach applied. However, these climate parameters and their interactions with infrastructure asset classes may merit further study to identify whether the adaptation measures recommended in the 2015 Study report are sufficient to address the expected changes.

Acronyms / Abbreviations

AEP	Annual Exceedance Probability
AR5	5th Assessment Report
AR6	6th Assessment Report
BCCAQv2	Bias Correction/Constructed Analogues with Quantile delta mapping reordering
CanDCS-U6	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
CMIP5	Coupled Model Intercomparison Project 5
CMIP6	Coupled Model Intercomparison Project 6
ECCC	Environment and Climate Change Canada
EF	Enhanced Fujita Scale
GCM	Global Climate Model
IDF	Intensity-Duration Frequency
IPCC	Intergovernmental Panel on Climate Change
NTP	Northern Tornadoes Project
PCIC	Pacific Climate Impacts Consortium
PIEVC	Public Infrastructure Engineering Vulnerability Committee
RCP	Representative Concentration Pathway
RSI	Risk Sciences International
SSP	Shared Socioeconomic Pathway

1 Introduction

This study was conducted by Stantec Consulting Ltd. (Stantec) to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The findings in this report are based on newly available global climate model (GCM) data from the 6th Coupled Model Intercomparison Project (CMIP6).

1.1 Background

A 2015 Study was conducted by AECOM and Risk Sciences International (RSI) using the latest climate projection information from the 5th Coupled Model Intercomparison Project (CMIP5) available at the time. The CMIP5 data was used to conduct a climate risk assessment using Engineers Canada's Public Infrastructure Engineering Vulnerability Committee's (PIEVC) assessment protocol (Engineers Canada, 2011) and estimate the vulnerability of Toronto Hydro's electrical distribution system to climate change and extreme weather events. The risk assessment included workshops, interviews, and an analysis of past climatic events to characterize the consequence of climate on Toronto Hydro's assets. Risk was evaluated by combining the climate hazard likelihood with the consequence information. The results of the 2015 Study were used to determine where infrastructure vulnerabilities to climate change were present and identify adaptation options to increase resilience.

In 2021, the IPCC released the 6th Assessment Report (AR6), as well as outputs from CMIP6, which represents an update to the latest climate change projection data from CMIP5. As one of the recommendations from the 2015 Study was to continue monitoring and evaluating climate change projection science, Toronto Hydro contracted Stantec to evaluate if the CMIP6 data will have a material change to the risk assessment set out in the 2015 Study.

1.2 Objective

The main objective of this assessment is to identify if any further study is required to update the adaptation actions recommended in the 2015 Study. This study uses updated climate projection data to estimate climate parameter probabilities and identifies whether these updates lead to materially different risk scores for Toronto Hydro's infrastructure asset classes over the study period.

1.3 Scope

The following scope of work has been completed as part of this assessment.

1. **Climate Parameter Probability Update:** Stantec collected downscaled CMIP6 global climate model data and reviewed scientific literature to estimate updated probability scores for the climate parameters found in the 2015 Study. This work aligns with Step 2, 'Data Gathering and Sufficiency' in version 10 of the PIEVC Protocol (Engineers Canada, 2011), as outlined in Section 1.2 of the 2015 Study.

2. **Materiality Assessment**: For those climate parameters where the probability score changed, Stantec re-calculated the study period risk score, to evaluate whether the change is material to each interaction. This aligns with Step 3, ‘Risk Assessment’, of the PIEVC Protocol, as outlined in Section 1.2 of the 2015 Study. We define a material change as one where the updated risk score fir an interaction crossed the risk tolerance thresholds from the 2015 Study.

Figure 1 outlines the work conducted in this study, and the nomenclature used to estimate climate-related risk to Toronto Hydro’s assets. Beginning with a review of climate data and scientific literature, we estimated the relevant climate parameters and their probabilities over the study period, then translated them to probability scores. The updated probability scores were used to re-calculate and revise the risk scores for each of the infrastructure asset class and climate parameter interactions investigated in the 2015 Study. For consistency with the 2015 Study, the methods and thresholds used to estimate the probability and risk scores followed those outlined in version 10 of the PIEVC Protocol (Engineers Canada, 2011).

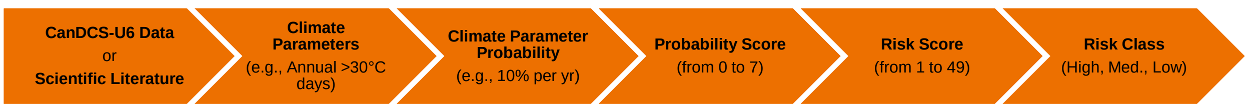

Figure 1: Project workflow

2 Climate Parameter Probability Update

This section describes the data and methods used to estimate updated climate parameter probabilities, and probability scores based on the updated climate data reviewed. The climate parameters investigated, and methods used to estimate probabilities align with the 2015 Study, except where noted otherwise.

2.1 Methodology

2.1.1 CLIMATE DATA

While the 2015 Study used coarse resolution (~200 km) climate projection information released along with the IPCC's 5th assessment report (AR5) – CMIP5, the Canadian Downscaled Climate Scenarios – Univariate (CMIP6), or CanDCS-U6, dataset produced by the Pacific Climate Impacts Consortium (PCIC) was used for this study. CanDCS-U6 is based on global climate model (GCM) outputs from the latest projections from the 6th Coupled Model Intercomparison Project (CMIP6), which were released in 2021. These represent a higher-resolution (~10 km grid) dataset that has been bias-corrected to align with a gridded historical weather reanalysis dataset (McKenney et al., 2011). The CanDCS-U6 dataset is delivered with daily resolution but is aggregated over 30-year time periods and across an ensemble of 26 models (Table 1) to estimate the range of climate parameter frequencies.

Table 1: Global Climate Models (GCMs) from CanDCS-U6 used in this study.

Model Name	Organization	Country	Organization Details
ACCESS-CM2	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS-ESM1-5	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM2-MR	BCC	China	Beijing Climate Center, China Meteorological Administration
CanESM5	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CMCC-ESM2	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM6-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CNRM-ESM2-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeende Recherche et Formation Avancees en Calcul Scientifique
EC-Earth3	EC-Earth	Europe	EC-Earth Consortium
EC-Earth3-Veg	EC-Earth	Europe	EC-Earth Consortium
FGOALS-g3	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences

Model Name	Organization	Country	Organization Details
GFDL- ESM4	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
HadGEM3-GC31-LL	MOHC	UK	MetOffice Hadley Centre
INM-CM4-8	INM	Russia	Institute for Numerical Mathematics
INM-CM5-0	INM	Russia	Institute for Numerical Mathematics
IPSL-CM6A- LR	IPSL	France	Institut Pierre-Simon Laplace
KACE-1-0-G	NIMS-KMA	Korea	National Institute of Meteorological Sciences, Korea Meteorological Administration Republic of Korea
KIOST-ESM	KIOST	Korea	Korea Institute of Ocean Science & Technology Republic of Korea
MIROC-E2SL	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere
MIROC6	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM1-2-HR	MPI-M	Germany	Max Planck Institute for Meteorology
MPI-ESM1-2-LR	MPI-M	Germany	Max Planck Institute for Meteorology
MRI-ESM2-0	MRI	Japan	Meteorological Research Institute
NorESM2-LM	NCC	Norway	Norwegian Climate Centre
NorESM2-MM	NCC	Norway	Norwegian Climate Centre
TaiESM1	AS-RCEC	China	Research Center for Environmental Changes, Academia Sinica
UKESM1-0-LL	Met Office - NERC	UK	Met Office Hadley Centre, Natural Environmental Research Council

Climate parameter probabilities from the 2015 Study relied on the Representative Concentration Pathway (RCP) 8.5 emissions scenario from CMIP5, which is largely consistent with the Shared Socioeconomic Pathway (SSP) 5-8.5 (from CMIP6) (Riahi et al., 2017). The RCP scenarios represent different levels of greenhouse gas (and other radiative forcings) that might occur by 2100 (e.g., RCP 8.5 represents an additional 8.5 Wm^{-2}). CMIP6 data is based on SSPs, which interpret how different levels of climate change mitigation (or lack thereof) could be achieved to reach specific greenhouse gas concentrations. While there is debate surrounding which pathway from CMIP6 is the most likely, the SSP5-8.5 pathway represents a high-emissions (more pessimistic) scenario (Riahi et al., 2017). Climate projection data from SSP5-8.5 was used for this analysis as a conservative estimate of future climatic conditions, and to maintain consistency with the 2015 Study.

The Toronto Hydro study area encompasses 21 grid cells from the CanDCS-U6 dataset (Figure 2). Stantec calculated applicable climate parameters across the entire 26-member ensemble of climate models, before calculating the mean, 10^{th} and 90^{th} percentiles over all models to produce most-likely, lower- and upper-end estimates for each parameter (see Appendix A). While recent studies (Hausfather et al., 2022) have shown that averaging the complete CMIP6 ensemble of models may overestimate future temperatures due to model bias, all model members of the CanDCS-U6 ensemble are bias-corrected using the BCCAQv2 method (Cannon et al., 2015; Werner and Cannon, 2019), which corrects any potential biases to an observed historical dataset.

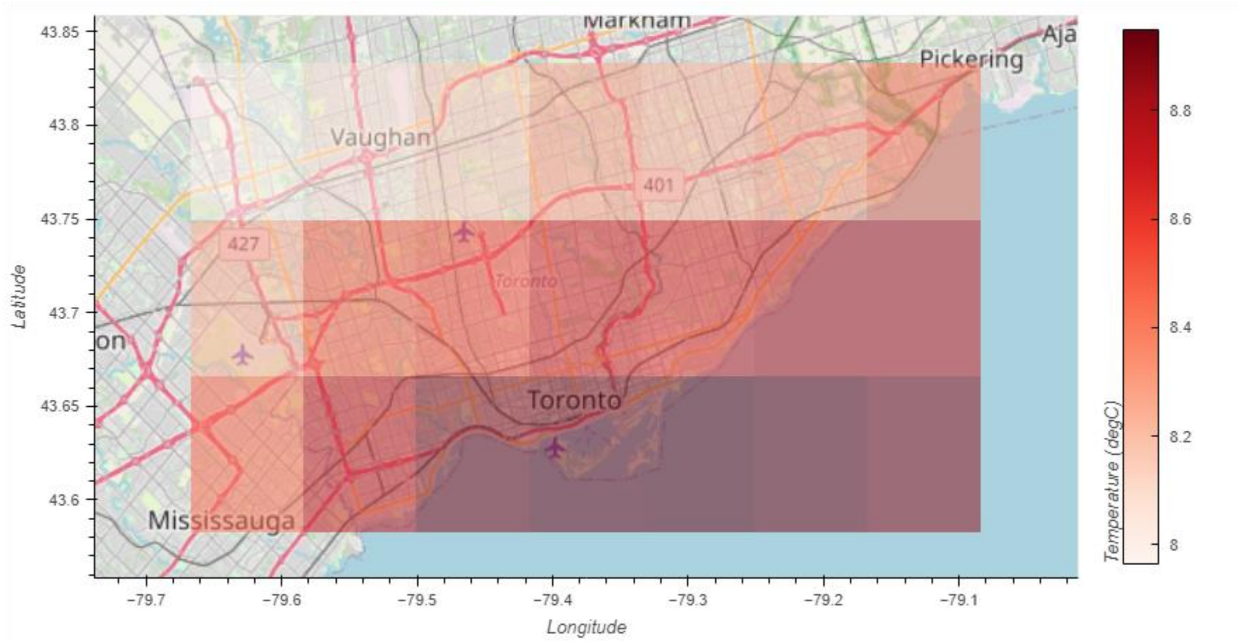

Figure 2: Mean air temperature over the baseline period (1981-2010), across the full CanDCS-U6 ensemble

Climate parameters that could not be calculated using the CanDCS-U6 data were investigated by conducting a literature review. The estimates of most of these parameters were derived using *Climate-resilient buildings and core public infrastructure (CRBCPI) 2020: An assessment of the impact of climate change on climatic design data in Canada* (Cannon et al., 2020). This document provides climatic design parameters based on the CanDCS-U5 dataset, which is a downscaled version of the CMIP5 data used in the 2015 Study. While the data are not based on the latest climate modelling (i.e., CMIP6), they do represent an update to the data used in the 2015 Study. Estimates of climate parameters that were not included in Cannon et al. (2020) relied upon other scientific publications identified by Stantec.

2.1.2 CLIMATE PARAMETER PROBABILITY

Some of the climate parameter probabilities were directly estimated from the CanDCS-U6 data (Table 2). Details on the methods used to calculate each parameter are provided in Section 2.2. To maintain consistency with the 2015 Study, the estimated frequencies/probabilities were adjusted to match the baseline values with those from the 2015 Study by applying the 'delta' approach as described in Appendix B, Section 3.3.1 of the 2015 Study report. The baseline probabilities from the 2015 Study are maintained in this study because their calculation relied on high-quality measurements obtained from weather stations, in contrast to the CanDCS-U6 baseline data, which rely on the less-precise NRCANmet dataset (Hopkinson et al., 2011).

Annual probabilities were estimated for the baseline period (1981-2010), the 2030s (2021-2050) and the 2050s (2041-2070), by dividing the number of event occurrences, by 30 years. The annual probabilities were then translated to study period probabilities by estimating the likelihood of occurrence over a 28-year period (from 2022 to 2050). Because seven years have passed since the 2015 Study (study period from 2015 to 2050), the length of the study period has changed, which influences the climate parameter probability of occurrence.

Table 2: Climate parameters and data sources used in the 2015 Study and the current (2022) study

Climate Parameter	Threshold(s)	2015 Data Source	2022 Data Source
Daily Maximum Temperatures	25°C, 30°C, 35°C, 40°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Snowfall	5 cm, 10 cm daily	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6); Cannon et al. (2020)
Ice Storm/Freezing Rain	15 mm, 25 mm, 60 mm	Cheng et al. (2011, 2014)	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)
High Winds	70 km/h, 90 km/h, 120 km/h	Cheng et al. (2012); Cheng (2014)	Cannon et al. (2020)
Tornado	EF1+, EF2+	Brooks et al. (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)
Lightning	Flash density per km km^2	Romps et al (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)

The updated climate parameter probabilities were categorized into one of the eight probability score classes used in the 2015 Study (Table 3). While more recent versions of the PIEVC protocol exist (e.g., the PIEVC High-Level Screening Guide – ICLR, 2022), Stantec applied the same scoring thresholds used in the 2015 Study to maintain consistency and comparability.

Table 3: Probability score classes applied in this study and the 2015 Study (from Engineers Canada, 2011)

Probability Score	Annual Probability	
0	<0.1 %	<1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	>99 %	>1 in 1.01

2.2 Results

Updates to the projected annual frequency (2030s), study period probabilities, and probability score for each climate parameter are summarized in Table 4. For parameters derived from the CanDCS-U6 data, the mean, 10th, and 90th percentiles of the frequency (across 26 models) are provided. A more detailed comparison, including baseline probabilities and 2050s projections is included in Appendix A for reference. Specific methods applied and results obtained for each climate parameter are described in detail later in this section.

Table 4: Updates to climate parameter probabilities

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Daily Maximum Temperatures	Days > 25°C	86 (64 - 102)	>99%	7	None
Daily Maximum Temperatures	Days > 30°C	28 (10 - 41)	>99%	7	None
Daily Maximum Temperatures	Days > 35°C	2.8 (0 - 7)	>99%	7	None
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
High Daily Avg. Temperature	Days > 30°C	0.75 (0 - 2.2)	>99%	7	None
Heat Wave	3+ consecutive days >30°C	2.6 (0.9 - 5.9)	>99%	7	None
High Nighttime Temperatures	Nighttime low ≥23°C	2.6 (0.1 - 5.9)	>99%	7	None

[1] Refers to annual frequency (days per year), unless otherwise noted in column 2. The values in parentheses indicate the 10th and 90th percentiles across 26 downscaled GCMs, from the CanDCS-U6 data.

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Snowfall	Days w/ >10 cm	1.2 (0 - 2.6)	100%	7	None
Snowfall	Days w/ > 5cm	4.4 (1.6 - 7.6)	100%	7	None
Frost-Free Days	Days > 0°C	249 (242 - 279)	100%	7	None
Extreme Rainfall	100 mm in <1 day + antecedent	+11% rainfall intensity	75%	6	None
Ice Storm/ Freezing Rain	Accretion 15 mm	-2.2% in 1/20yr ice accretion	99%	7	None
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)
Ice Storm/ Freezing Rain	60 mm ≈ 30 mm radial	-2.2% in 1/20yr ice accretion	23%	4	None
High Winds	>70 km/h+	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>90 km/h	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>120 km/h	+0.8% in 25-yr wind speeds	76%	7	None
Tornado	EF1+	-	~0.6%	1	None
Tornado	EF2+	-	~0.3%	0	None
Lightning	Flash density per year per km^2	1.43	55% (Lg)	6	None

2.2.1 HEAT-RELATED PARAMETERS

Each of the heat-related parameters (Daily Maximum Temperature, High Daily Average Temperature, Heat Wave, and High Nighttime Temperature) were calculated directly from the CanDCS-U6 data. These parameters were shifted using an additive correction factor to match the baseline values to those provided in the 2015 Study. The heat-related climate parameters are defined as follows:

- Daily Maximum Temperatures above threshold temperature (25°C, 30°C, 35°C, and 40°C) – number of days per year when the maximum daily temperature exceeds a threshold.
- High Daily Average Temperature (above 30°C) – number of days per year when the average daily temperature exceeds 30°C.
- Heat Waves – number of times per year when the maximum daily temperature exceeds 30°C for three or more consecutive days.
- High Nighttime Temperatures (above 23°C) – number of days per year when minimum daily (nighttime) temperature exceeds 23°C.

There is an increase in the estimated number of days with maximum temperatures exceeding 25°C, 30°C, and 35°C in the 2030s and 2050s compared to the 2015 Study (see Appendix A). For each of these parameters, the probability of occurrence over the study period is almost certain (>99%). Because the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, these values remain unchanged.

There is a decrease in the estimated number of days with maximum temperatures exceeding 40°C in the 2030s and 2050s, compared to the 2015 Study. As a result, the estimated probability of 40°C temperatures occurring over the study period is about 90% and is classified as a probability score of 6, a decrease from the 2015 Study score of 7.

The projected number of days with daily average temperature greater than 30°C is higher than that provided in the 2015 Study, increasing from 1.2 days per year to 4.3 days per year. The CanDCS-U6 data were also used to estimate the frequency in the 2030s, which was not previously provided. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of heat waves per year aligns with the values provided in the 2015 Study, however the CanDCS-U6 data allow for a more precise estimate of the annual frequency in the 2030s and 2050s. The 2015 Study projected more than 1 heat wave per year in the 2030s and 2050s, whereas the updated climate data indicate that 2.6 and 4.8 heat waves are expected per year, respectively. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of days with high nighttime temperatures is lower than the estimates provided in the 2015 Study, decreasing from 7 and 16 to 3 and 11 in the 2030s and 2050s, respectively. While this represents an almost 50% decrease, the probability of occurrence over the study period is still almost certain (>99%), and therefore the updated climate data do not justify a change to the probability score of 7 assigned in the 2015 Study.

2.2.2 FROST-FREE DAYS

Frost-free days were estimated using the CanDCS-U6 data. This parameter represents the number of days per year when the daily minimum temperature exceeded 0°C. The frequencies estimated from the CanDCS-U6 data were shifted using an additive correction factor to match the baseline value to that provided in the 2015 Study.

While there is a slight increase in the estimated number of frost-free days in the 2050s compared to the 2015 Study (increase 5 days), the differences are small in comparison to the annual number of frost-free days projected (278 days). Further, the 2015 Study assigned a probability score of 7 (>99%) over the study period. This score means that frost days (i.e., temperatures below 0°C) are effectively certain throughout the study period. These findings are supported by the updated climate data, and the probability scores remain unchanged.

2.2.3 EXTREME RAINFALL

While extreme rainfall events at the daily and higher resolution can be captured by the CanDCS-U6 dataset, the latest recommendations from Environment and Climate Change Canada (ECCC) suggest alternate methods to estimate future extreme rainfall. The approach uses the relationship between warming temperatures and precipitation extremes to update empirically based rainfall intensity-duration-frequency (IDF) curves for future climate projections (Canadian Standards Association, 2019). This method is described as 'temperature scaling', which is defined as $\boldsymbol{R_P = R_C \times 1.07^{\Delta T}}$, where R_P is future estimated rainfall intensity value, R_C is the current rainfall intensity value, and ΔT is long-term (30-years or more mean) annual mean temperature change for the study location. IDF change factors ($1.07^{\Delta T}$) based on CMIP5 data for cities across Canada are provided in Cannon et al (2020), accounting for site-specific projections in temperature change.

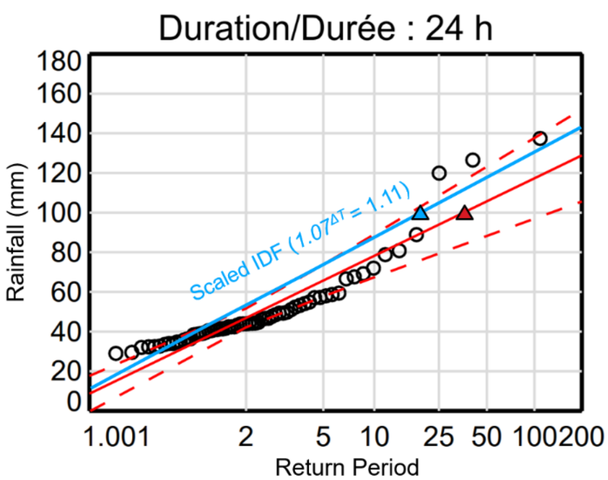

Figure 3: Scaled 24-hour rainfall probability curve for Toronto Pearson Airport, from ECCC. Triangles denote 100-mm rainfall probabilities for the baseline (red) and 2030s (blue).

For the Toronto area, the IDF change factor is given as 1.11, for the year 2035 (midpoint of the 2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The 2015 study provides a baseline annual probability of 4% for 100 mm of rain in 24 hours, which generally agrees with the latest IDF curves for the Pearson Airport weather station, provided by ECCC (3%, or 33-year return period) (blue triangle, Figure 3). Applying the change factor to the latest IDF curve for Pearson Airport, gives an estimated annual probability of ~5% for a 100mm/24hr rainfall event in the 2030s (red triangle, Figure 3) and a study period probability of 75%. Using Table 3, this results in a probability score of 2 for the 2030s, and 6 for the study period, which is the same as that provided in the 2015 study.

While using downscaled climate model (e.g., CanDCS-U6) rainfall data is not the recommended approach for estimating future extreme rainfall probabilities from ECCC, the approach still merits investigation for this analysis. The mean probability of >100mm of rainfall in a 24-hour period across the CanDCS-U6 ensemble in the 2030s is ~0.02 (score of 2) resulting in a study period probability of 57% (score of 6), which agrees with the recommended approach discussed above.

2.2.4 SNOWFALL

The future probabilities of 5 and 10 cm snowfall events were estimated using the CanDCS-U6 data. Snowfall was approximated from temperature and precipitation data using the 'Brown' method presented in Verseghy (2009), which assumes the fraction of precipitation falling as snow decreases linearly between 0 °C (100% snow and 0% rain) and 2 °C (0% snow and 100% rain). The results were then converted from mm of water equivalent to snow depth (in cm) using a density of 150 kg/m^3, which was selected to align with the number of 5 and 10 cm snowfall events provided in the 2015 Study (i.e., the snow density was used as a multiplicative correction factor). Cannon et al. (2020) notes that while there is medium confidence that snow loads will decrease over most of Southern Canada, there is low confidence in the magnitude of the decrease.

The results indicate the annual frequency of 5 cm snowfall events will decrease from 5.2 events per year in the baseline period to 4.4 in the 2030s, and 3.1 in the 2050s. Larger (10 cm) snowfall events are estimated to decrease in frequency from 1.4 events per year in the baseline to 1.2 and 0.9 events per year in the 2030s and 2050s, respectively. Despite the projected decrease in annual frequency of snowfall events, the probability of both 5 and 10 cm snowfall events occurring over the study period is almost certain (>99%), and therefore the probability scores from the 2015 Study remain unchanged (score of 7).

2.2.5 FREEZING RAIN

The future probabilities of freezing rain events were estimated based on a review of recent climate change literature applicable to the Toronto area, including McCray at al. (2022), Jeong et al. (2018), and Cannon et al (2020). The freezing rain events considered included 15, 25, and 60 mm of ice accretion, as defined in the 2015 Study.

While the studies do not explicitly provide estimates of the likelihood of the freezing rain events listed in the 2015 Study, McCray et al. (2022) and Jeong et al. (2018) found that the frequency, and magnitude, respectively, of freezing rain events are projected to decrease slightly in the Toronto area. Cannon et al. (2020) found 'with medium confidence' that while the magnitude of freezing rain events is expected to increase across Canada in general, there is a very small, expected decrease in the Toronto area (very low confidence). Specifically, they estimate reductions of 2.2% and 7.7% in ice thickness for the 1/20-year (5% annual exceedance probability) events based on 1°C and 1.75°C of global mean warming. These global mean warming estimates are consistent with the years 2035 (2030s) and 2055 (2050s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1).

As a conservative approach, Cannon et al (2020) recommend using ice accretion loads established from recent historical data (i.e., no projected change in ice storm magnitude). In consideration of each of these sources, and the significant uncertainty expressed in each, the estimates probability score for each type of freezing rain event (10, 20, 30 mm) is likely to remain steady over the study period, as compared to the baseline. The updated study period probability scores are not changed for 10- and 30-mm events (7 and 4, respectively), but are decreased (from 7 to 6) for 20 mm events, compared to the 2015 Study.

2.2.6 WIND

The future probabilities of extreme wind events were estimated based on a review of recent climate change literature for the Toronto area (Cannon et al,2020). The extreme wind events considered include 70, 90 and 120 km/h wind thresholds, as defined in the 2015 Study.

Cannon et al. (2020) project a slight increase of extreme wind speeds in the Toronto area, with very low confidence. They estimate increases of 0.7% and 0.8% in hourly wind speeds for the 1/10-year (10% annual exceedance probability; AEP) and 1/25-year (4% AEP) events based on +1.0°C of global mean warming, which is consistent with the year 2035 (2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The estimated increases for +1.75°C (equivalent to 2055/2050s for RCP8.5) are 2.7% and 3.4% for 1/10-year and 1/25-year events, respectively. These return periods were selected from the available data provided by Cannon et al (2019) to best align with the baseline probabilities from the 2015 Study (>100% AEP for 70 and 90 km/hr events, and 5% AEP for 120 km/hr events).

Cannon et al. (2019) emphasize that these wind speed projections are provided with very low confidence, because of (1) the limited amount of scientific literature, (2) a low signal-to-noise ratio in the projected changes, and (3) the general inability of climate models to simulate extreme winds associated with small-scale processes that influence wind speeds. Because the projected increases in wind speeds are small, and the confidence is very low, we have assigned probability scores that are consistent with the baseline for each threshold event (7, 7, and 2 for 70 km/hr, 90 km/hr and 120 km/hr events, respectively), which are also consistent with the scores from the 2015 Study.

2.2.7 TORNADOES

A review of recent climate change literature applicable to the Toronto area was conducted to identify whether any updates were required to the tornado probability estimate from the 2015 Study. The specific tornado events considered included those with strengths of EF1+ (wind speeds exceeding 138 km/h) and EF2+ (wind speeds exceeding 178 km/h) on the Enhanced Fujita (EF) scale.

Sills et al. (2020) used multiple methods (e.g., satellite imagery, drone and ground surveys) to identify tornadoes and assess their size and intensity in the Ontario region between 2017 and 2019 as part of the Northern Tornadoes Project (NTP). Using a systematic approach, they captured 78% to 283% more tornadoes annually than the 30-year Canadian national tornado dataset from 1980-2009, mainly due to their increased usage of satellite imagery, ground and drone surveys and an improved storm track identification. It is important to note that although there is a detected increase in tornado occurrence through NTP, it does not signify any relevant changes in the tornado frequency in Canada.

Figure 4 shows all NTP-documented tornadoes (from 2017-2019) in Southeastern Ontario, with selected contours from the tornado frequency modeling of Cheng et al (2013). Gensini and Brooks (2018) note that tornado environments have been shifting northeastward in the central United States, however Sills et al. (2020) emphasize that it would take numerous years before any trends could be confirmed in Canada. In

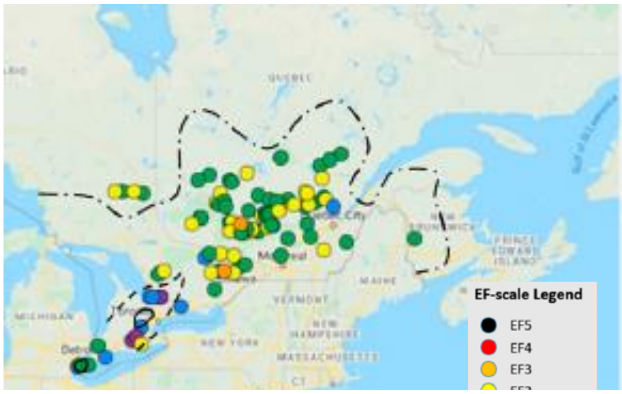

Figure 4: 2017-2019 tornadoes recorded by Sills et al. (2020), overlain with contours of annual tornado frequency in tornadoes per 10,000km2 per year from Cheng et al. (2013): dash-dotted = 0.1, dashed = 1.0, solid=2.0.

consideration of each of these sources, and the uncertainty expressed in each, the tornado probability scores from the 2015 Study remain unchanged (1 and 0 for EF-1 and EF-2 tornadoes, respectively).

2.2.8 LIGHTNING

The future probability of lightning was estimated based on a review of recent climate change literature and data applicable to the Toronto area (Romps et al (2014), Romps (2018) and Finney et al. (2018)). Lightning probability is quantified using the flash density per km^2.

The baseline probability of lightning events provided in the 2015 Study was estimated using data collected from the North American lightning detection network between 1999 and 2008. Environment Canada has since published mean annual lightning flash-density values for the Toronto Area over the period of 1999-2018. Because the time period of the updated data is twice as long as that from the data provided in the 2015 report, the new value provided by Environment Canada is used in this study. The updated value is 1.43 flashes per km^2 per year, which is consistent with the range provided in the 2015 Study (1.12-2.24 flashes per km^2 per year).

As noted in the 2015 Study, Romps et al. (2014) estimate that lightning strikes are projected to increase by 7-17% per degree Celsius of global warming. Similarly, Romps (2018) estimate increases of 8-16% per degree Celsius of warming, using two separate indices. Finney et al. (2018) however, applied a different approach to estimate changes in lightning frequency with climate change, and found that lightning frequency may decrease with warming global temperatures. Due to the general lack of literature linking lightning to climate change, the lack of consistency between projections, and the limited number of models applied in these studies, it is estimated the probability of lightning occurrence will not change significantly under a changing climate. As such, the probability score over the study period is 6, which represents no change from the 2015 Study.

3 Materiality Assessment

3.1 Materiality Methods

Each combination of climate parameter and infrastructure asset class is referred to as an interaction (e.g., the interaction between extreme heat and downtown core stations). To assess material changes in risk, Stantec calculated risk over the study period (2022-2050) for each interaction. Risk is calculated following the approach outlined in the 2015 Study, where ***Risk Score = Probability Score x Severity Score*** (Engineers Canada, 2011). Updated risk scores were only calculated for climate parameters for which the probability score differed from that assigned in the 2015 Study (freezing rain events (>25mm) and extreme heat events (>40°C)). Severity scores used to estimate risk in the 2015 Study were also used in this study.

Updated risk scores were calculated for 66 interactions (42 infrastructure asset classes and two climate parameters – note that some infrastructure asset classes are not exposed to extreme heat or ice storms). The results were then compared with the tolerance thresholds from the 2015 Study to classify the risks. Material changes (either positive or negative) were then identified based on whether the risk score crossed the threshold into a new class.

Table 5: Risk tolerance thresholds (classes) from the 2015 Study

Risk Score	Risk Class	Response
<12	Low Risk	Monitoring or no further action necessary
12 - 36	Medium Risk	Vulnerability may be present. Action may be required, to be determined through engineering analysis
>36	High Risk	Vulnerability present, action required

3.2 Materiality Results

Only two of the updated climate parameters probability scores were different from the 2015 Study: (1) daily maximum temperatures (>40°C) and (2) freezing rain/ice storms (>25 mm). Each of these probability scores, were reduced from a very high probability (7) to high probability (6). Based on these updated probability scores, the estimated risk for 23 of the interactions were calculated to be materially different from the 2015 Study. The materially different interactions, and their risk scores, are outlined below and in Table 6.

- Ten infrastructure asset classes at high risk to daily maximum temperatures >40°C changed to medium risk. All these material changes were for Transmission Step-down to Municipal and Municipal Stations.
- Thirteen infrastructure asset classes at high risk to freezing rain events >25 mm changed to medium risk. These material changes were for Transmission Step-down to Municipal and Municipal Stations as well as Overhead loops as part of the feeder configuration and emergency response.

Table 6: Summary of interactions with material changes to risk scores

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Individual material risk classification changes are outlined in Table 7 with references to specific adaptation options from the 2015 Study and report.

Table 7: Material risk classification changes and adaptation option outcomes

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
High Temperature (40°C)	**1**	**Transmission Step-Down to Municipal**				• Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.1	Downtown core stations	42	**36**	↓	
	1.1.2	Downtown outer stations without a station	42	**36**	↓	
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations (divided by Geography)**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.1	Former Toronto (indoor/outdoor)	42	**36**	↓	
	2.1.3	Toronto Hydro to private ownership	42	**36**	↓	

[2] Adaptation recommendations are from Table 7-1 of the 2015 Study.

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
Freezing Rain /Ice Storm (>25 mm)	**1**	**Transmission Step-Down to Municipal**				• Management actions to account for changes in the infrastructure capacity • Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.2	Station (13.8 kV)	42	**36**	↓	
	1.2.3	East Stations	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.6	Station	42	**36**	↓	
	1.2.7	Northwest Station	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.2	Horseshoe Area (indoor/outdoor)	42	**36**	↓	
	3	**Feeder Configuration: Underground**				• Management actions to account for changes in the infrastructure capacity • Remedial engineering actions which aim to strengthen or upgrade the infrastructure
	3.5	**Overhead**				
		Loop				
	3.5.4	4.16 kV	42	**36**	↓	
	6	**Human Resources**				• Management actions to account for changes in the infrastructure capacity
	6.1	Emergency Response	42	**36**	↓	

4 Discussion

The results presented in the preceding sections show the updated climate projection information reviewed does not result in any material increases to the risk scores presented in the 2015 Study. However, there are a few differences between the climate parameter probabilities and risk scores that merit further discussion.

While many of the climate parameter probabilities/frequencies have increased (see Appendix A), the climate parameter probability score for the study period provided in the 2015 Study was already at the highest possible level (7, or greater than 99% annual probability). As a result, any notable increases in the frequency of these climatic events based on the updated data are not reflected in this risk assessment. To address this issue, the latest PIEVC guidance, released in the High-Level Screening Guide (ICLR, 2022) would dictate that some of these parameters should be evaluated using the 'middle-baseline' approach.

In the middle-baseline approach, the future probability score is dependent on the projected percent change in climate parameter frequency compared to the baseline (with a default baseline probability score of 3). More specifically, the middle baseline approach dictates that a >10% increase in climate parameter frequency, would result in an increase in the probability score from 3 to 4, and a >50% increase would result in a score of 5. Based on this approach, we have identified the climate parameters where probability scores of 7 from the 2015 Study could not be increased and where the projected 2030s frequency changed by more than 10% compared to that presented in the 2015 report.

- High Daily Average Temperature >30°C (increase from 0.6 to 0.8 days/year)
- Heat Waves (increase from >1 to 2.6 days/year)
- High Nighttime Temperatures >23°C (decrease from 7 to 3 days/year)

Although the probability scores (and hence the associated risk scores) for the above climate parameters are unchanged from the 2015 Study, their associated adaptation measures may merit further study to evaluate whether they are sufficient to address the differences in climate parameter frequencies.

While we found a slight decrease in the number of infrastructure asset classes at high risk due to extreme heat (>40°C) events, the range in climate parameter probabilities over the study period is broad across the CMIP6 model ensemble, and the probability score is very close to being a 7 over the study period (90% probability of occurrence). Therefore, although the change materially decreases based on this analysis, we do not recommend relaxing any of the adaptation measures proposed in the 2015 Study.

The 2015 Study estimated the probability score of freezing rain/ice storms events (>25 mm) would increase in the 2030s. Updated climate projection information suggests the probability will remain steady over the study period. Although we do not have an ensemble of models to consider for this climate parameter, the literature investigated expressed 'very low confidence' in the projections, and therefore the probability could range widely. Therefore, although the change materially decreases, based on this analysis, we do not recommend relaxing any of the measures associated with freezing rain events >25 mm.

5 Limitations

The findings in this report are subject to several limitations. Section 2 discusses specific uncertainties associated with each climate parameter. Some overarching limitations are noted below.

- Stantec did not review the 2015 Study adaptation recommendations to assess if they were sufficient to protect infrastructure assets against the relevant climate hazard, as this would have been beyond the scope of this study. The results from this study could be used to evaluate which of the adaptation recommendations merit further review.
- Climate data is inherently uncertain. The climate parameter probabilities provided should be considered as high-level estimates of future conditions. The primary source of uncertainty in climate projections is the estimate of greenhouse gas emissions that will be observed over the current century. Additional sources of uncertainty include (but are not limited to) climate model parameterization, bias, and resolution.
- Some of the climate parameters investigated are associated with very high degrees of uncertainty, because they are difficult to constrain using the outputs from climate models. Stantec has reviewed recently published scientific literature and guidance to provide an estimate of likely future conditions.
- The severity scores, as well as the thresholds used to define risk and climate parameter probability classes and scores were not reviewed as part of this analysis. The thresholds are consistent with those applied in the 2015 Study.

6 Closure

This study has provided an update to the climate parameters described in the 2015 Study, using newly available CMIP6 climate model data. By analyzing the CMIP6 data, as well as recent scientific literature and guidance documents, Stantec has updated the estimated risk scores for Toronto Hydro’s infrastructure assets by applying the same risk assessment framework as was applied in the 2015 Study. Some parameters (heat waves, and daily average temperatures >30°C) are expected to occur more frequently than projected by the 2015 study, however, these events were already considered to be ‘certain’ over the study period in the 2015 Study. The only climate parameter probability scores that changed as a result of this analysis include extremely hot days (>40°C), and 25mm freezing rain events, both of which are projected to occur less frequently over the study period than was estimated in the 2015 Study. Though these decreases resulted in a downgrading from high to medium risk for multiple infrastructure asset classes, we do not recommend relaxing any of the adaptation measures provided in the 2015 Study.

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APPENDICES

Appendix A – 2022 Climate Parameter Probability Update

Climate Parameter	Threshold	2015 Study								2022 Study								Study Period Probability Difference (2022-2015)
		Data Source	Annual Frequency			Probability Score			Study Period Probability (2015-2050)	Data Source	Annual Frequency - Corrected			Probability Score			Study Period Probability (2022-2050)	
			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2015-2050)			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2022-2050)		
Daily Maximum Temperatures	25°C	CMIP5 Ensemble (IPCC AR5)	66	84	106	7	7	7	100%	CanDCS-U6 Ensemble	66 (47 - 76)	86 (64 - 102)	110 (86 - 126)	7	7	7	>99%	No Change
Daily Maximum Temperatures	30°C	CMIP5 Ensemble (IPCC AR5)	16	26	47	7	7	7	100%	CanDCS-U6 Ensemble	16 (4 - 22)	28 (10 - 41)	50 (25 - 74)	7	7	7	>99%	No Change
Daily Maximum Temperatures	35°C	CMIP5 Ensemble (IPCC AR5)	0.75	3	8	6	7	7	100%	CanDCS-U6 Ensemble	0.8 (0 - 1.5)	2.8 (0 - 7)	9.2 (0.5 - 22.5)	6	7	7	>99%	No Change
Daily Maximum Temperatures	40°C	CMIP5 Ensemble (IPCC AR5)	0.01	0.3-2	1-7	1	4-7	7	~100%	CanDCS-U6 Ensemble	0.01 (0 - 0)	0.08 (0 - 0.1)	0.64 (0 - 1.98)	1	5	6	90%	Decrease
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	0.07	0.565	1.2	3	7	7	~100%	CanDCS-U6 Ensemble	0.07 (0 - 0.04)	0.75 (0 - 2.22)	4.31 (0 - 11.72)	3	7	7	>99%	No Change
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	0.88	>1	>1	6	7	7	100%	CanDCS-U6 Ensemble	0.9 (0.2 - 3.3)	2.6 (0.9 - 5.9)	4.8 (2.9 - 8.3)	6	7	7	>99%	No Change
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	0.70	7	16	6	7	7	~100%	CanDCS-U6 Ensemble	0.7 (0 - 1.3)	2.6 (0.1 - 5.9)	10.7 (2.3 - 20.8)	6	7	7	>99%	No Change
Snowfall	Days w/ >10 cm	CMIP5 Ensemble (IPCC AR5)	1.5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	1.4 (0.1 - 2.8)	1.2 (0 - 2.6)	0.9 (0 - 2.2)	7	7	7	>99%	No Change
Snowfall	Days w/ > 5cm	CMIP5 Ensemble (IPCC AR5)	5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	5.2 (2.2 - 8.5)	4.4 (1.6 - 7.6)	3.1 (0.5 - 6)	7	7	7	>99%	No Change
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	229	249	273	7	7	7	100%	CanDCS-U6 Ensemble	229 (225 - 256)	249 (242 - 279)	278 (264 - 320)	7	7	7	>99%	No Change
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	0.04	Expected increase	Expected increase	2	3	6	~75%-85%	Cannon et al. (2020); CanDCS-U6 Ensemble	0.02	+11% rainfall intensity	+20% rainfall intensity	2	2	6	75%	No Change
Ice Storm/Freezing Rain	15 mm (tree branches)	Cheng et al. (2011, 2014)	0.11	0.13	0.16	3	3	7	>99%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.11	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	3	3	7	99%	No Change
Ice Storm/Freezing Rain	25 mm ≈ 12.5 mm radial	Cheng et al. (2011, 2014)	0.06	0.07	0.09	2	3	7	>95%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.06	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	2	2	6	96%	Decrease
Ice Storm/Freezing Rain	60 mm ≈ 30 mm radial	Cheng et al. (2011, 2014)	0.005	0.013	0.007	1	1	4	High: ~25% Low: ~8%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.005	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	1	1	4	23%	No Change
High Winds	70 km/h+ (tree branches)	Cheng et al. (2012); Cheng (2014)	21	N/A	25	7	7	7	100%	Cannon et al. (2020)	21	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	90 km/h	Cheng et al. (2012), Cheng (2014)	2	N/A	>2.5	7	7	7	100%	Cannon et al. (2020)	2	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	120 km/h	N/A	0.05	Likely Increase	Likely Increase	2	2	7	~85% or higher	Cannon et al. (2020)	0.05	+0.8% in 25-yr wind speeds	+3.4% in 25-yr wind speeds	2	2	7	76%	No Change
Tornado	EF1+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	No Change
Tornado	EF2+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	No Change
Lightning	Flash density per km km^2	Romps et al (2014)	1.12-2.24/yr/km^2	Expected increase, % unknown	Expected increase, % unknown	0-2	N/A	3-6	~50-70%(Lg); ~10-20% (Sm)	Romps et al (2014), Romps (2018), Finney et al. (2018)	1.43	1.43	1.43	1	1	6	55% (Lg)	No Change

Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters

Climate Change Vulnerability Assessment Update
Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters
November 18, 2022

	Infrastructure Class or Category	4 High Temperature 40°C								10 Freezing Rain/Ice Storm 25 mm ≈ 12.5 mm radial							
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
1	**Transmission Step-down to Municipal**																
1.1	**Former Toronto**																
1.1.1	Downtown core stations	Y	7	6	5+	6	42	**36**	↓	N							
1.1.2	Downtown outer stations without a station	Y	7	6	5+	6	42	**36**	↓	N							
1.1.3	Station (13.8 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2	**Horseshoe Area**																
1.2.1	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.2	Station (13.8 kV)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.3	East Stations	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.4	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.5	Station (27.6 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.6	Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.7	Northwest Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.8	2 Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.9	Southwest Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
2	**Municipal Stations**																
2.1	**TO Hydro to TO Hydro & Private Ownership**																
2.1.1	Former Toronto (indoor/outdoor)	Y	7	6	5+	6	42	**36**	↓	N							
2.1.2	Horseshoe Area (indoor/outdoor)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
2.1.3	Toronto Hydro to private ownership	Y	7	6	5+	6	42	**36**	↓	N							
3	**Feeder Configuration: Underground**																
3.1	**Horseshoe Area: Dual Radial System**																
3.1.1	Submersible type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.2	Vault type																
	Above ground	Y	7	6	3	3	21	**18**	↔	N							
	Below ground	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.3	Padmount Station	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.2	**Former Toronto: Dual Radial System**																

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
		40°C								25 mm ≈ 12.5 mm radial							
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
3.2.1	Submersible type	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.2	Vault Type																
	Above ground	Y	7	6	3+	4	28	**24**	↔	N							
	Below ground	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.3	Padmount Station	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.3	**Compact Loop Design**																
3.3.1	Former Toronto: Subway Type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.4	**13.8 kV Network**																
3.4.1	Former Toronto	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.5	**Overhead**																
	Radial																
3.5.1	4.16 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	6+	7	49	**42**	↔
3.5.2	13.8 kV Network	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
3.5.3	27.6 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
	Loop																
3.5.4	4.16 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	6	6	42	**36**	↓
3.5.5	13.8 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
3.5.6	27.6 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
4	**Communications**																
4.1	Protection and control systems	Y	7	6	2	2	14	**12**	↔	N							
4.2	SCADA and Wireless Network	Y	7	6	1	1	7	**6**	↔	Y	7	6	1	1	7	**6**	↔
5	**Civil Structures**																
5.1	**Transmission and Municipal Stations**																
	Outdoor																
5.1.1	Equipment support	N								N							
5.1.2	Gantry	N								Y	7	6	1	1	7	**6**	↔
5.2	**Underground feeders: Former Toronto**																
5.2.1	Reinforced concrete cable chambers	N								Y	7	6	1+	2	14	**12**	↔

Infrastructure Class or Category		4 High Temperature 40°C								10 Freezing Rain/Ice Storm 25 mm ≈ 12.5 mm radial							
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
5.2.2	Concrete vaults (reinforced)	N								Y	7	6	1+	2	14	**12**	↔
5.2.3	Underground cable ducts	N								N							
5.3	**Underground feeders: Horseshoe Area**																
5.3.1	Reinforced concrete cable chambers	N								Y	7	6	1	1	7	**6**	↔
5.3.2	Concrete vaults (reinforced)	N								Y	7	6	1	1	7	**6**	↔
5.3.3	Underground cable ducts	N								N							
6	**Human resources**																
6.1	Emergency Response	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓

Appendix C – 2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section D
Appendix D
ORIGINAL
(204 pages)

Clean Air Partnership

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

June 2015

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report - Public

6031-8907

June 2015

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Executive Summary

The current study aims to evaluate the vulnerability of Toronto Hydro's electrical distribution system within the City of Toronto to a changing climate by employing Engineers Canada's Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol). This study is a high level screening analysis designed to determine where infrastructure vulnerabilities to climate change may be present, to suggest avenues for adapting infrastructure to climate change, and to identify areas of further study.

Electrical Distribution System under Study

Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city and home to approximately 2.8 million people in 2014. Toronto Hydro serves approximately 740,000 customers in the City of Toronto and owns approximately $3 billion dollars in assets, including over 170 transformer stations, approximately 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles.

The study period of this assessment was 2015 to 2050. A "system" level approach was employed to assess the impacts of climate change on the various parts of the electrical distribution system. This approach divided the distribution system into six major asset categories: stations, feeders, communications systems, civil structures, auxiliary mechanical systems and human resources. Asset categories were assessed based on their general characteristics (e.g. typical, representative or common electrical or mechanical configurations, standards, equipment). For example, this analysis focused on how systems designed to current (post 2000) CSA standards may interact with the climate parameters being considered. Changes to the electrical system considered in this assessment included the planned transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[1], and replacement of non-submersible equipment. The streetlighting system and systems serving the Toronto Transit Commission (TTC) were not within the scope of this study.

Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff (through ongoing communications and two workshops) were all used to help identify and describe asset categories, general characteristics and sensitivities to climate related stresses (climate parameters[2]).

Climate Parameters

20 climate parameters including high temperature, heavy rainfall, snowfall, freezing rain, high winds and lightning were considered in this assessment. Relevant climate parameters and threshold values at which infrastructure performance would be affected were identified through a literature review, consultations with Toronto Hydro staff and analysis of past outage events.

The probability of a climate parameter occurring during the study period was determined using global climate modelling (GCM) data obtained from the Intergovernmental Panel on Climate Change's 5th Assessment Report (IPCC AR5). In many cases, this information was validated or refined through the use of regional climate modelling data, statistical downscaling and climate analogues.

The probability of a climate parameter occurring is expressed both as a study period probability value (i.e. what is the probability of a climate parameter occurring sometime between 2015 – 2050) and an annual probability value centred around the 2030's and 2050's (i.e. what is the annual probability of a climate parameter occurring around

[1] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. Vulnerabilities were determined based on the assumption that gradual population growth would generally be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

[2] A climate parameter is defined by the PIEVC Protocol as a specific set of weather conditions or climate trends deemed to be relevant to the infrastructure under consideration. The parameter may be a single variable, such as mean monthly temperature, or a combination of variables, such as low temperature combined with rainfall.

the 2030's and 2050's). Examining both annual and study period probability was useful for understanding vulnerabilities that may stem from events which could occur on an annual basis (e.g. high temperature) against those which could occur less than annually, but have the potential to cause significant damage to the system sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes). The list of climate parameters considered in this study is shown in table ES-1.

Table ES-1 Climate Parameters and Probability of Occurrence

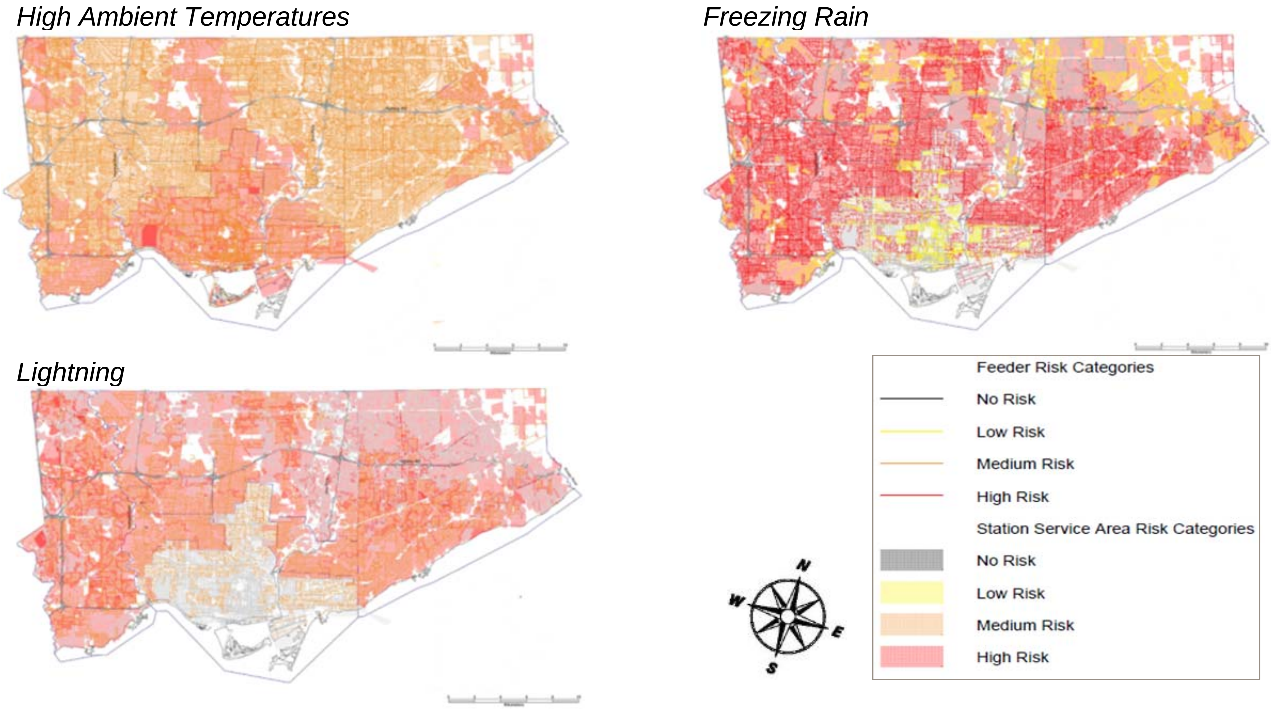
Climate Parameter		Annual Probability (Historical; **Projected 2030's and *2050's***)	Probability of Occurrence Study Period (2015-2050)
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%
	30°C	16 per year; **26 per year**, ***47 per year***	100%
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%
	40°C	~0.01 per year; **0.3 to 2 days per year, *1-7 days per year***	~100%
High Daily Avg. Temperature	30°C	0.07 per year; **N/A, *1.2 days per year***	~100%
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%
High Nighttime Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%
	60 mm ≈ 30 mm radial	Upper bound of estimate: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Lower bound of estimate: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%
High Winds	70 km/h+ (tree branches)	21 days per year***;*** **N/A, *24 to 26 per year***	100%
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%
Lightning	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%

Assessing Vulnerability

The vulnerability of the electrical system to climate parameters was determined using a risk based framework (probability of occurrence of a climate parameter coupled with the severity/consequence of the impact on the system). All high risk interactions were deemed as vulnerabilities for Toronto Hydro. Medium risk interactions were evaluated in further detail through an engineering analysis. Those which exhibited sensitivities or consequences similar to high risk interactions were also deemed as vulnerabilities for Toronto Hydro. Finally, interactions rated as low risk were generally judged as not being a significant issue or vulnerability for Toronto Hydro.

A mapping of the risk ratings was also completed as part of this study and represents a useful first approximation of spatial nature of climate change vulnerabilities to the electrical system. The mapping exercise provides additional information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets, while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city. This mapping information can be easily combined with other layers of information such as technical hazard information (e.g. flood mapping), critical building and infrastructure locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to support further mapping studies and in depth analyses.

Figure ES-1 Example Maps Based on Risk Ratings for High Heat, Freezing Rain and Lightning



This study found that distribution system vulnerabilities to a changing climate were divided into five groups based on how climate parameters affect the system.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting power transformer capacity and electrical transmission efficiency. Two climate parameters were of most significant concern, daily maximum temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. For these climate parameters, the analysis found that such extreme temperatures have occurred rarely in the past, but are projected to occur almost semi-annually by the 2030's, and annually by the 2050's. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events can cause immediate structural issues for overhead station and feeder assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, ice weight) or by other objects (e.g. tree branches, flying debris). Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual, or even decadal frequency. Nonetheless, the damages caused by these kinds of events can be severe, and mostly affect outdoor station and feeder assets, much of which is concentrated in the horseshoe service area.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets. These vulnerabilities are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro. As such, current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate this problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, de-icing salts will also be applied annually through the study horizon, and corrosion will continue to be an ongoing preoccupation. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's interruption tracking system's (ITIS) outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning strikes will continue to be an area of vulnerability.

Adaptation Options and Areas of Further Study

This study provides high level adaptation options under the themes of engineering actions, management actions, monitoring activities and further study. Generally, for high heat related climate parameters, Toronto Hydro could further investigate avenues to enhance the system's capacity to deal with higher demand under high temperature conditions, especially since extreme heat events are projected to occur on a semi-annual to annual basis by the 2030's and 2050's. On climate events causing structural damage issues (i.e. freezing rain, ice storms, high winds and tornadoes), adaptation options include optimizing emergency response and service restoration, as well as infrastructure hardening and burying infrastructure. While the latter engineering-type solutions are relatively capital intensive, asset renewal cycles provide excellent opportunities to consider these types of upgrades. This study also recommends that Toronto Hydro continue monitoring the occurrences and impacts of major freezing rain, high wind and tornado events on the system, as well as the science of climate change projections. This multi-faceted approach provides Toronto Hydro with greater flexibility in managing vulnerabilities related to these types of extreme climate events.

Other potential options to address identified vulnerabilities include continued monitoring and evaluation of climate change projection science, monitoring impacts of a changing climate on certain asset classes, evaluating the need to strengthen or defend certain infrastructure and equipment from climate parameters, and enhancing emergency response and service restoration practices.

Acknowledgements

This study was completed with support from Natural Resources Canada. It was produced through its Adaptation Platform Electrical Sector Working Group[3]. AECOM would also like to acknowledge Engineers Canada for the technical support, participation and for the use of its Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The Toronto region's WeatherWise Partnership is also acknowledged for its work on bringing the issue of climate related threats on electrical infrastructure to the forefront, and for its support in bringing about this study. AECOM would like to thank the Clean Air Partnership for the opportunity to undertake this study.

AECOM would also like to acknowledge Toronto Hydro staff for their time and effort in providing information about their system, participating in workshops and meetings, providing insight into the functionality of their system, and reviewing documents and reports. Without their valuable contributions, this study could not have proceeded.

[3] For more information on climate change impacts and adaptation, please visit adaptation.nrcan.gc.ca" (or for French language publications/sites: "adaptation.rncan.gc.ca").

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List of Acronyms

CAP	Clean Air Partnership
GCM	Global climate model
GIS	Geographic Information Systems
HONI	Hydro One Networks Inc.
ITIS	Interruption Tracking System
NRCan	Natural Resources Canada
OPG	Ontario Power Generation
PIEVC	Public Infrastructure Engineering Vulnerability Committee
Protocol	The climate change based public infrastructure vulnerability assessment developed by the PIEVC and Engineers Canada
RCM	Regional climate model
RCP	Representative concentration pathway
RSI	Risk Sciences International
THESL	Toronto Hydro-Electric System Limited
TTC	Toronto Transit Commission

1 Study Context

1.1 Introduction and Mandate

In 2012, Engineers Canada partnered with the Clean Air Partnership (CAP) and Toronto Hydro to evaluate the risks of climate change on Toronto Hydro's electrical distribution infrastructure in the City of Toronto. At that time, CAP mandated AECOM and Risk Sciences International (RSI) to undertake a Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol, or the Protocol)[4] based study on select components of Toronto Hydro's electrical distribution system to historical climate. That study, named the Toronto Hydro-Electric System PIEVC Pilot Case (pilot case study), was meant to demonstrate the applicability of the Protocol to electrical systems. The pilot case study was also envisioned as the first of a two-phase project to assess climate change related vulnerabilities to electrical systems. The pilot case study was completed at the end of summer 2012 (AECOM and RSI, 2012).

In summer 2013, CAP and Toronto Hydro elected to pursue the second phase of the climate change assessment with support from Natural Resources Canada's (NRCan) "Enhancing Competitiveness in a Changing Climate" program. NRCan's program is designed to facilitate the development and sharing of knowledge, tools and practices which assist decision-makers in the analysis and implementation of climate change related adaptation measures. CAP, once again mandated AECOM and RSI to carry out the Phase 2 climate change vulnerability assessment (Phase 2 study). The Phase 2 study is the subject of the current report.

1.2 Methodology and Approach

The Phase 2 study again employs the Protocol as the framework for the climate change analysis. The Protocol is composed of five steps:

- Step 1 – Project Definition;
- Step 2 – Data Gathering and Sufficiency;
- Step 3 – Risk Assessment;
- Step 4 – Engineering Analysis;
- Step 5 – Recommendations and Conclusions.

In contrast to the pilot case study, the scope of Phase 2 study was extended to include most of Toronto Hydro owned electrical distribution infrastructure and civil support structures across the City of Toronto. Toronto Hydro's streetlighting system and electrical systems for the Toronto Transit Commission were not within the scope of the present study. Anticipated climate changes and impacts at the 2030 and 2050 time horizons were evaluated. Most of the activities prescribed by the Protocol were completed as part of Phase 2 with the exception of a site visit. The triple-bottom line adaptation solutions development module, an optional undertaking in the PIEVC Protocol, was also not completed as part of Phase 2 of this study[5].

As part of the activities of Phase 2, two workshops were held with Toronto Hydro staff. The first workshop was held on July 3, 2014 in Toronto Hydro's offices in Toronto. At this workshop, an overview of the infrastructure and climate components (Steps 1 and 2 of the Protocol), were presented for discussion and validation with Toronto Hydro staff. On October 10, 2014, a second workshop was held to validate the risk assessment completed by AECOM and RSI (Step 3 of the Protocol).

4 The Protocol is a structured and documented methodology for a screening level assessment of infrastructure vulnerability to a changing climate, and for developing adaptation solutions to identified vulnerabilities. The Protocol, currently in version 10, also allows users to evaluate the vulnerabilities stemming from current climate to the infrastructure as part of the overall assessment.

5 The triple-bottom line adaptation solutions development module guides users in the development and screening of potential solutions to address the impacts of climate change identified in the preceding steps of the Protocol. It was not in the scope of the current study.

The components of the electrical distribution system (e.g. stations, power lines, transformers, switches, supports) under study are highly interdependent, and failures in one part of the system may result in interrelated structural, electrical or functional issues in other portions of the system (e.g. failures in poles may bring down power line and transformers, electrical faults may cause the system to lose protection, control or redundancy). For this reason, the study of electrical systems cannot be examined solely on the basis of its individual pieces or classes or equipment. This study adopts a *systems level approach*[6] to examining the climate change risks to the extensive, complex and interdependent components of Toronto Hydro's electrical distribution system. This approach divides the electrical distribution system into six major systems categories encompassing different individual components and classes of equipment. This generalization of electrical components into major systems categories facilitates an analysis that considers system dependencies and redundancies.

However, by generalizing the system into major systems categories, the granular detail of the system and its components (e.g. site specific characteristics, unique or individual pieces of equipment) may not be adequately captured. Therefore, to complete a reasonable study of the entire electrical distribution system, this study has made assumptions, informed by input from Toronto Hydro staff, about the types and classes of equipment and components typically found within each category. While the loss of granular detail may mask localized issues and vulnerabilities, it does allow this project to provide the first climate change based vulnerability assessment of electrical distribution infrastructure. This can help prioritize future investigations, resources and investment on vulnerable systems and their components in order to enhance the resilience of the electrical system.

1.3 Structure of this Report

This report is divided into seven chapters, including the present one. They are:

- Chapter 1: Study Context;
- Chapter 2: Description of the Infrastructure;
- Chapter 3: Assessment of Climate Changes;
- Chapter 4: Vulnerability Assessment Methodology;
- Chapter 5: Assessment Results;
- Chapter 6: Engineering Analysis; and,
- Chapter 7: Conclusions.

Note that Chapter 3, Assessment of Climate Changes and **Appendix B** and **C**, were authored by Risk Sciences International in consultation with AECOM study authors.

[6] This is in contrast to the component level analysis approach which was employed in the pilot case study.

2 Description of the Infrastructure

2.1 Study Area

The Phase 2 study covers Toronto Hydro's electrical distribution infrastructure and supporting civil infrastructure within the boundaries of the City of Toronto. Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city, the provincial capital of Ontario, and home to approximately 2.8 million people (City of Toronto, 2014). The City of Toronto is bordered by the municipalities of Mississauga to the west (in Peel Region), Vaughan and Markham to the north (in York Region), and Pickering to the east (in Durham Region).

The City of Toronto covers approximately 641 km^2 on the northwestern shore of Lake Ontario (City of Toronto, 2014). The city's topography slopes gradually from the lakeshore, approximately 75 m above sea level to 200 m above sea level at its highest point along its northern border (City of Toronto, 2014). Three river systems cross the City of Toronto and flow into Lake Ontario. The Humber River lies on the west side of the City. The Don River essentially crosses the middle of the City of Toronto and flows into Lake Ontario just east of downtown. Finally, the Rouge River crosses the city's eastern edge. These rivers, their tributaries and creeks total about 307 km of water courses and punctuate the City's generally flat landscape with ravines.

The City lies at the eastern edge of the Carolinian Forest zone. The City contains approximately 10 million trees, approximately 4 million of which are publically owned. Of the latter, there are approximately 600,000 trees along streets and public right of ways, and another 3.5 million trees in parks, ravines and other natural areas of the city (City of Toronto, 2014).

2.1.1 Major Systems Categories Under Study

In 2014, Toronto Hydro's electrical distribution system served approximately 740,000 customers, of which around 658,000 were residential customers. The components of the Toronto Hydro's electrical distribution system are extensive, covering approximately $3 billion dollars in assets, including over 170 transformer stations of different classes, 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles (Toronto Hydro, 2014b). The present study covers most of Toronto Hydro's electrical distribution infrastructure and civil support structures, with the exclusion of its streetlighting system, and systems serving the Toronto Transit Commission (TTC). The electrical distribution system was divided into six *major systems categories* for the purposes of this study: transmission stations, feeder configurations, system communications, civil structures, mechanical auxiliaries and human resources. Figure 2-1 provides a schematic overview of the systems under study. The *major systems categories* are described hereafter, and hypotheses and generalizations that were made to facilitate the *system level analysis* approach are explained in this chapter. Supporting detail is included in Worksheet 1 of **Appendix H**.

This analysis divides the City of Toronto into two areas: the Former Toronto area and horseshoe area. This distinction is made because most of the legacy equipment is usually found in downtown Toronto and while equipment of newer design can usually be found in the horseshoe area. As such, the *major systems categories* (with the exception of human resources) are also separated between the Former Toronto area (which represents the downtown and inner city) and the horseshoe area (which covers the outlying suburbs). Figure 2-2 shows the division between the Former Toronto area (in green) and the horseshoe area (in blue).

Information about the *major systems categories* was drawn from three principal sources:

- *Overview of the Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 203 p.
- *Overview of the Toronto Area Transmission Systems and Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 121 p.

- System Expansion and Studies Section System Reliability Planning Department. *Toronto Hydro Distribution System Planning Guidelines.* Toronto Hydro-Electric System Limited, 2007, 22 p.

Figure 2-1 Major System Categories Under Study

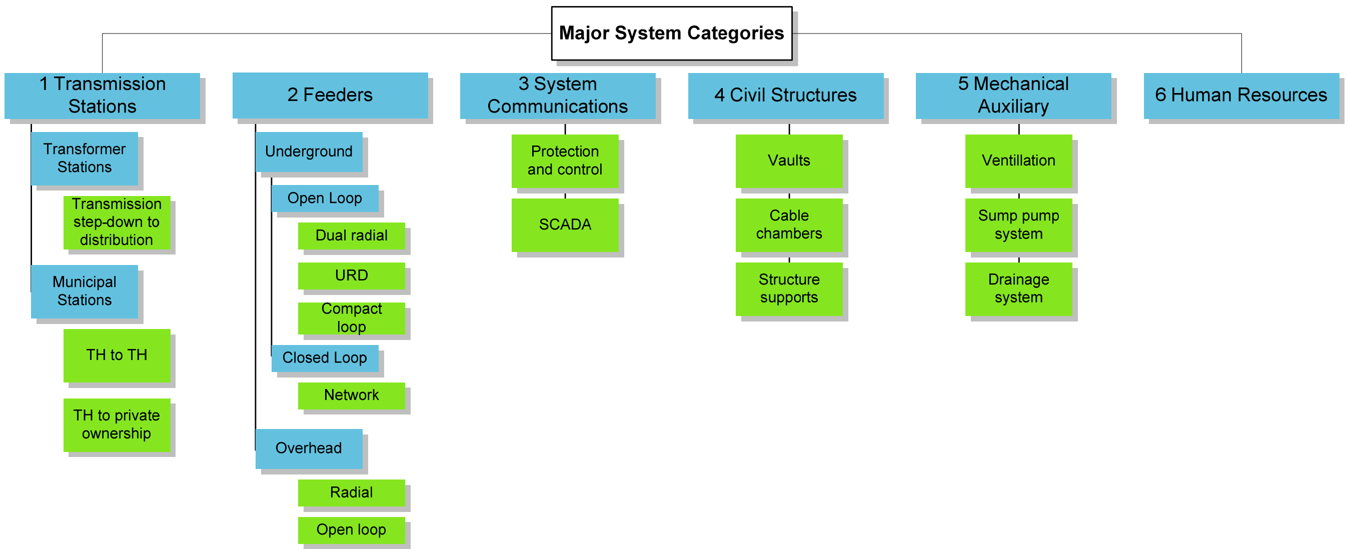
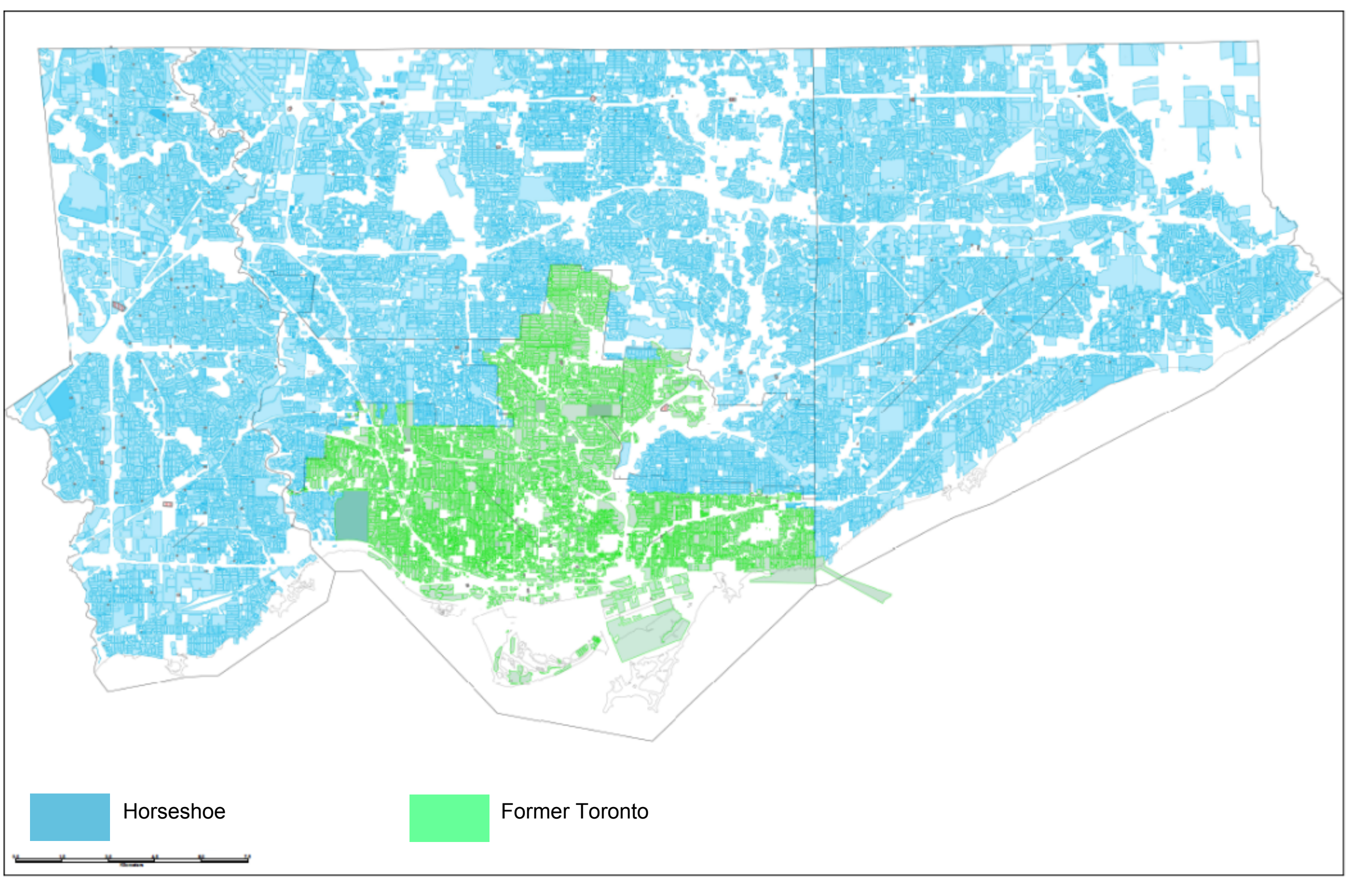


Figure 2-2 City of Toronto Study Area



2.2 General System Overview

The electric power system of the province of Ontario is a large interconnected electrical system of generating, transmission, and distribution infrastructure. Generating stations in Ontario are either privately or publicly owned. From the generation stations, the electricity is transmitted throughout the province over high voltage transmission lines, the majority of which is owned by Hydro One Networks Inc. (HONI). The electricity is then distributed to customers by local distribution companies like Toronto Hydro (Figure 2-3).

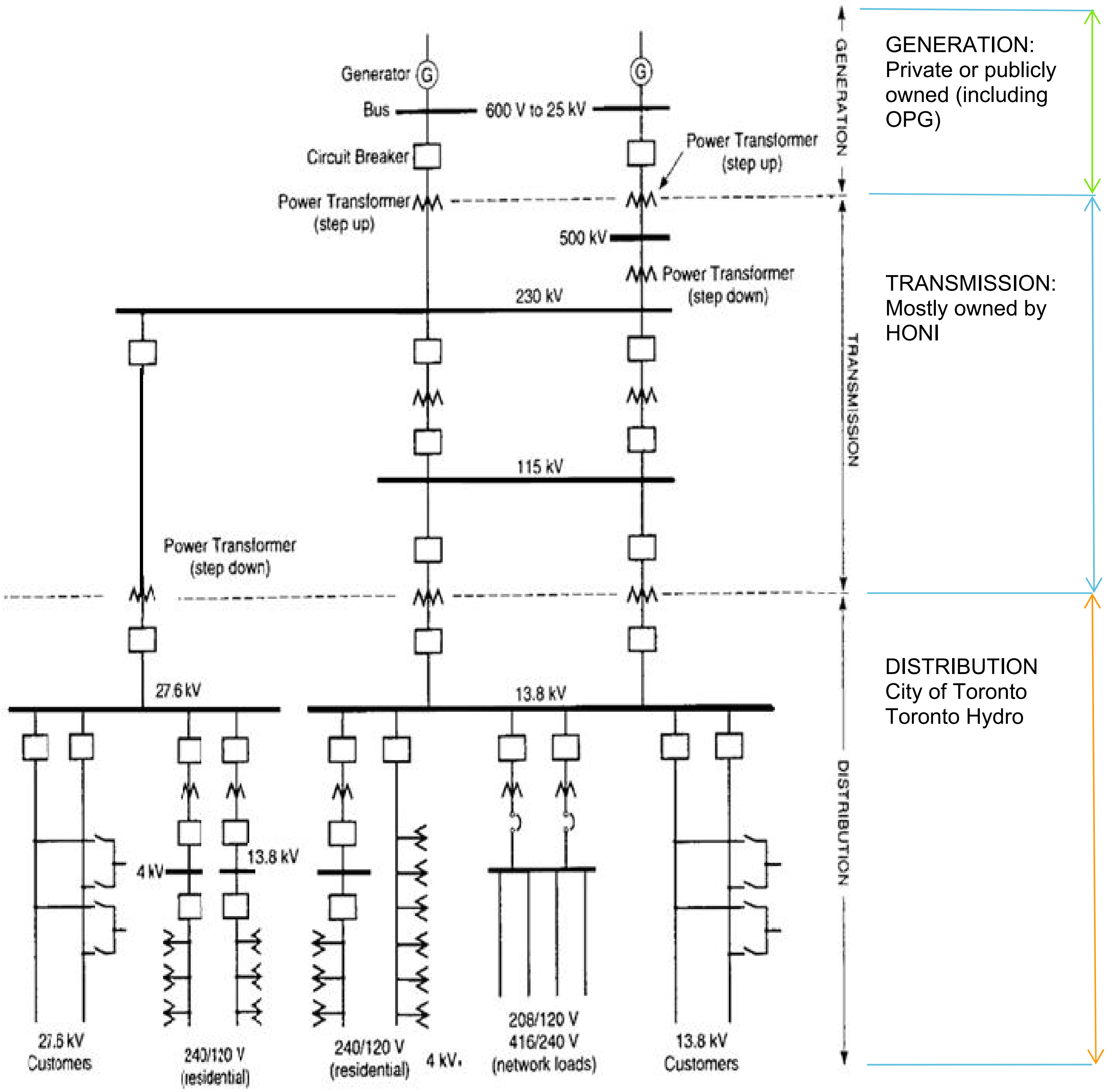
In the case of the City of Toronto, 230 kV and 115 kV transmission lines owned and operated by HONI bring power to the city. The 230 kV transmission lines mostly serve the horseshoe area, while the 115 kV lines serve most of the Former Toronto area. The 115 kV transmission lines are supplied from three major sources: Leaside station (230/115 kV step down) from the east, Manby station (230/115 kV step down) from the west, and by one generating station located within city limits, the Portlands Energy Centre (PEC) owned by Ontario Power Generation (OPG). PEC generates electricity through three natural gas turbine generators.

Presently, there are 35 transmission stations that step down high voltage currents (230 kV and 115 kV) to the distribution system voltages used by Toronto Hydro (i.e. 27.6 kV and 13.8 kV) (Figure 2-4). The equipment within these stations is owned by either Hydro One or Toronto Hydro, with the exception of Cavanagh station, where all equipment is owned by Toronto Hydro. The division of equipment ownership varies by station. However, since transmission stations are critical, first points of entry of electricity into the city's distribution network, this study considers all equipment within the transmission station, since equipment failure within the station, irrespective of ownership, may compromise its function.

From transmission stations, Toronto Hydro distributes electricity via a network of underground and overhead feeder systems at voltages of 27.6 kV and 13.8 kV. A third distribution voltage level of 4.16 kV, a legacy from historical distribution practices, also operates in the city. The 4.16 kV network is supplied by transformation of 27.6 kV or 13.8 kV feeds at Toronto Hydro owned municipal transformer stations. These three distribution voltages will remain in service for the duration of the Phase 2 study period, even though many of the 4.16 kV power lines are gradually being converted to 13.8 kV and 27.6 kV lines.

This electrical distribution infrastructure is connected via communications systems which afford control and protection of electrical equipment from damage or faults. This system is critical to the operation of the electrical system and is part of this study. In addition, this study considers all civil structures that support the electrical equipment and all mechanical equipment inside underground vaults (ventilation, sumps and pumps). A last category includes all human resources operating and managing Toronto Hydro distribution system.

Figure 2-3 Typical Electric Power System



Source: (Toronto Hydro, 2014d)

Figure 2-4 Transmission Stations

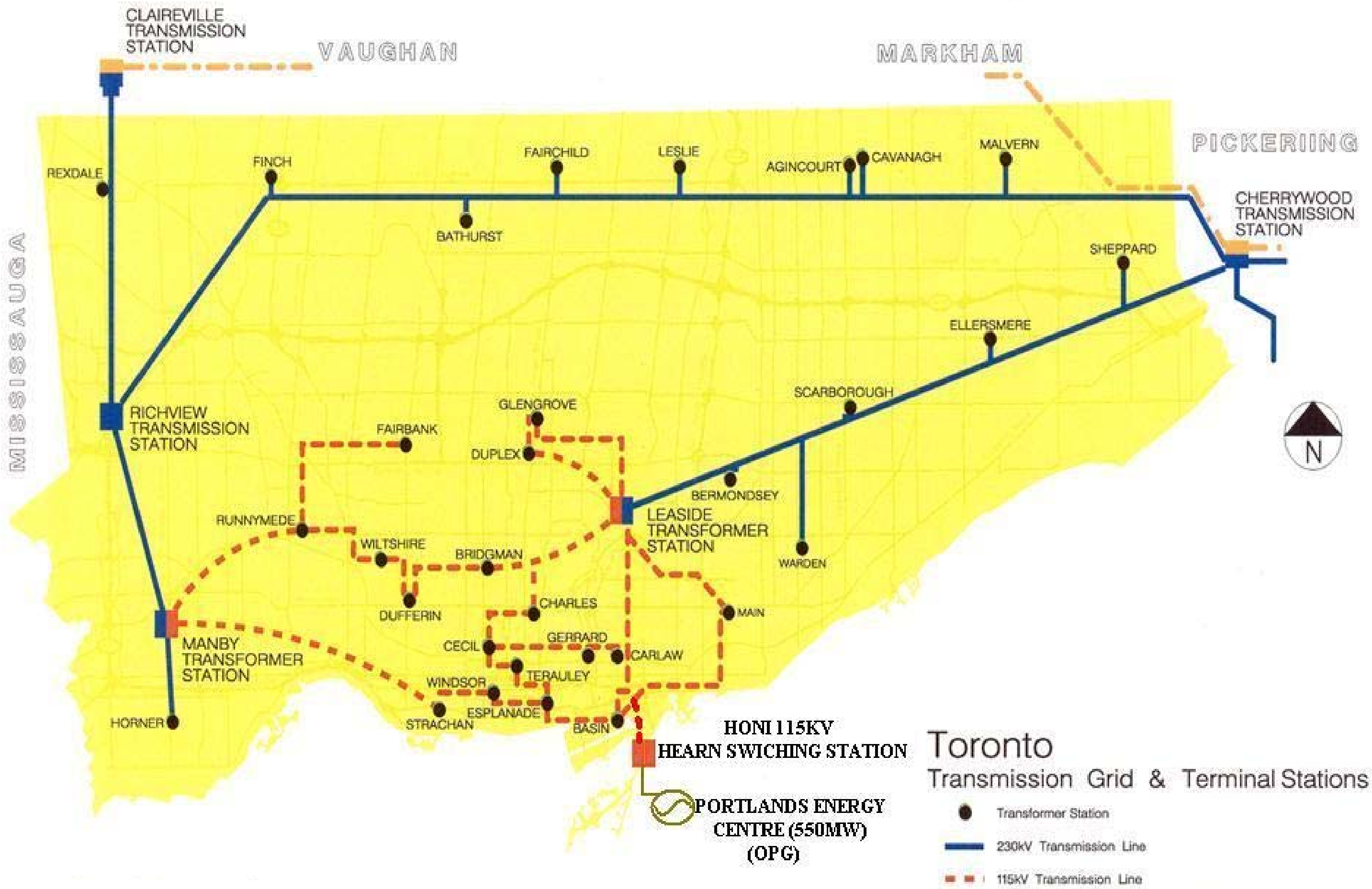


Figure source: (Toronto Hydro, 2014d)

2.3 Substations

2.3.1 Transmission Stations

At the moment, there are 35 transmission stations located in the City of Toronto. Most transmission stations located in the downtown and inner city have primary voltages at 115 kV and step-down to 13.8 kV. In the horseshoe area, the primary voltage is 230 kV and stepped-down to 27.6 kV (most) or 13.8 kV (some). The table below illustrates the list of stations that are divided into the two main service areas, and six sub-service areas[7] (Table 2-1).

[7] Stations have been grouped into these service areas by Toronto Hydro due to:
- Similarity of historical development and presumed potential for future development;
- Theoretical potential for permanently transferring load between neighbouring stations on an operational basis and/or through capital projects;
- Statistical correlation (coefficient of determination, R2) of the overall area growth rate to actual historical peak loads in the area (relative to potential alternative area groupings).

Table 2-1 Transmission Stations and Service Areas[8]

Service Area *(Voltage step down)*	Number of Stations
Former Toronto	
Downtown core *(115 kV/13.8 kV)*	6
Downtown outer *(115/13.8 kV, 230/115 kV, 115/27.6 kV)*	11
Horseshoe	
North Stations *(230/27.6 kV)*	2
East *(230 kV/27.6 kV, 230/115 kV)*	10
Northwest *(230 kV/27.6 kV)*	4
Southwest *(230/27.6 kV, 230/115 kV)*	2

In the Former Toronto area, there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. In the horseshoe area, there are existing station ties available to allow the transfer some feeder loads from one station to another.

In the horseshoe area, the transmission stations are considered "outdoor", as all equipment's are exposed to the elements. A control building containing weather sensitive equipment and operators control room is located adjacent to the station. In the Former Toronto area, most stations are configured with equipment located indoors. The entire transmission station is surrounded by fences or walls for public safety.

All stations are essentially based on the Dual Element Spot Network (DESN) design configuration. Typically DESN has two power transformers with 230 kV or 115 kV primary windings, two 27.6 kV or 13.8 kV secondary windings and two buses.

By 2016, the Copeland Station (a gas insulated station) will be brought into service in the Former Toronto area. Gas Insulated Stations occupy less space than air insulated stations of comparable capacity. The gas used for insulation in the Copeland Station is Sulfur Hexafluoride (SF6).

Typical equipment – Transmission Stations

While each of the 35 transmission stations have site specific characteristics, representative and typical equipment found in all stations are:

[8] Station names have been excluded from this version of the report.

- Power transformers
- Lightning arresters
- Current and voltage transformers (instrument transformers)
- Disconnect-switches or interrupters (loadbreak switches)
- Circuit Breakers
- Medium voltage switchgears
- Bus bars
- Transmission station configurations: double bus - double breaker configuration, double bus - single breaker, double bus - double breaker or double bus and one and a half breakers.

A picture of a typical transmission station yard is shown in Figure 2-5.

Figure 2-5 The Station Yard at Cavanagh Transmission Station

Picture source: (Toronto Hydro, 2014a)

Note that this station *major systems category* does not include civil structures or protection and control systems. These other critical infrastructure components which form part of the transmission station are described under separate *major systems categories* below.

2.3.2 Municipal stations

The municipal stations are divided into two sub-categories. First, “Toronto Hydro to Toronto Hydro” municipal stations step down from 27.6 kV to 13.8 kV or to 4.16 kV in the Horseshoe Area, and in the Former Toronto area from 13.8 kV to 4.16 kV. There are also smaller transformer stations located on the sites of Toronto Hydro customers with high load demands. These stations are called “Toronto Hydro to Private ownership” stations in this study.

Toronto Hydro is converting its 4.16 kV voltage level over time to 13.8 kV and 27.6 kV because of age, loss minimization, equipment inventory reduction, and required or projected future load growth (Toronto Hydro, 2007). Toronto Hydro estimated that by 2030, 50% of the 4.16 kV equipment will be converted in the Horseshoe Area and all of it will be phased out in the Former Toronto area. By 2050, Toronto Hydro is expected to have replaced 70% of the 4.16 kV overhead power lines in the Horseshoe (Hypotheses issued in Workshop 1, 2014).

Toronto Hydro to Toronto Hydro

There are around 169 municipal stations (27.6 kV/ 13.8kV or 27.6 kV/13.8 kV / 4.16 kV) within the City of Toronto. Approximately 82 municipal stations are located entirely within a building, and these indoor stations are mostly located in the Former Toronto area. The remaining stations have some or all equipment located outdoors. These stations are classified as outdoor stations for the purposes of this study, and most are located in the horseshoe area. Figure 2-6 shows a picture of a typical outdoor station located in a residential area. For the purpose of this study, it is assumed that all Former Toronto area municipal stations are indoors, while horseshoe stations are outdoors. For those few outdoor stations in the Former Toronto area, their vulnerability will be identical to the outdoor stations in the horseshoe area.

Figure 2-6 Residential Area MS (front and rear views)

Figure source: (Toronto Hydro, 2014a)

Toronto Hydro to Private Ownership

Toronto Hydro to Private Ownership stations supply large loads at low voltages to private customers. The station is located on private property inside a closed room. Most of these stations are owned by Toronto Hydro, although some are owned by the customer.

<u>Typical equipment – Municipal Stations</u>

Typical equipment within municipal stations is similar to transmission stations, but are generally smaller in size because less capacity is required. In general, municipal stations include:

- Oil power transformers (ONAN/ONAF);
- Instrument transformers;
- Disconnect switches;
- Circuit Breakers;
- Cables;
- Fuses;
- Arresters.

2.4 Feeder Systems

Toronto Hydro employs feeder systems, or systems of power lines, transformers, switches and related equipment, to distribute electricity across the City of Toronto. The feeders are either installed on overhead poles (overhead systems) or travel through underground cables (underground systems). Overhead feeder systems can be located on the front side of a property (front lot) or at the back of the property (rear lot). However, rear lot systems will be phased out by the 2030s and are not considered in the scope of this study. They are progressively being replaced by front lot overhead or underground infrastructure, which provides Toronto Hydro more convenient access. In total, Toronto Hydro customers are served by over 900 feeders[9] (Navigant Consulting Ltd. 2011).

Approximately 30 % of Toronto Hydro's distribution network is comprised of 27.6 kV feeders from 3 - 4 km (considered ''short'' lines) to 5 - 6 km (considered ''long'' lines) in length. These systems are mostly located in the horseshoe area. 70 % of Toronto Hydro's distribution feeders operate at 13.8kV, and vary in length between 2 – 3 km (short) to 3 - 4 km (long) (Navigant Consulting Ltd., 2011). The 13.8 kV systems serve both the downtown and horseshoe areas. A very small percentage of feeders still operate at 4.16 kV.

2.4.1 Electrical Configurations

The electrical configuration of a feeder determines the way electricity is delivered to customers. It is indicative of the feeder's ability to provide electrical service in the event of equipment damage and electrical faults. There are many different electrical configurations of feeders, and they include radial, dual radial, open loop and closed loop systems. Some of these systems may also be nested within one another (e.g. an open loop system with downstream radial feeders). Toronto Hydro's main underground and overhead feeders are arranged in an open loop type configuration, although there are also dual radial and radial feeder systems, some of which may be nested within the open loop configuration. Only one feeder type, the 13.8 kV network, is arranged in a closed loop type configuration. The various electrical configurations considered in this study are:

- Underground dual radial and underground residential distribution (URD) feeders;
- Underground closed loop network feeders;
- Overhead open loop and radial feeders.

In the open loop system, the feeder line runs out of the station through two separate feeder arms that eventually reconnect outside the station to form a loop. A load interrupting switch (tie switch) is located at the reconnection point and is normally kept open between the two feeder arms. If one feeder arm goes out, the load can be fed by the other feeder arm by closing the tie switch. In open loop systems under single contingency condition[10], the customer typically experiences an interruption when the feeder is switched from one feeder arm to the other.

In radial systems, the customer is supplied by only one feeder. It is the least expensive design but also offers the least flexibility in electrical service restoration in the event of a fault, as there is no other feeder that can supply electricity until the line is repaired. Radial feeder segments may be nested within open loop systems.

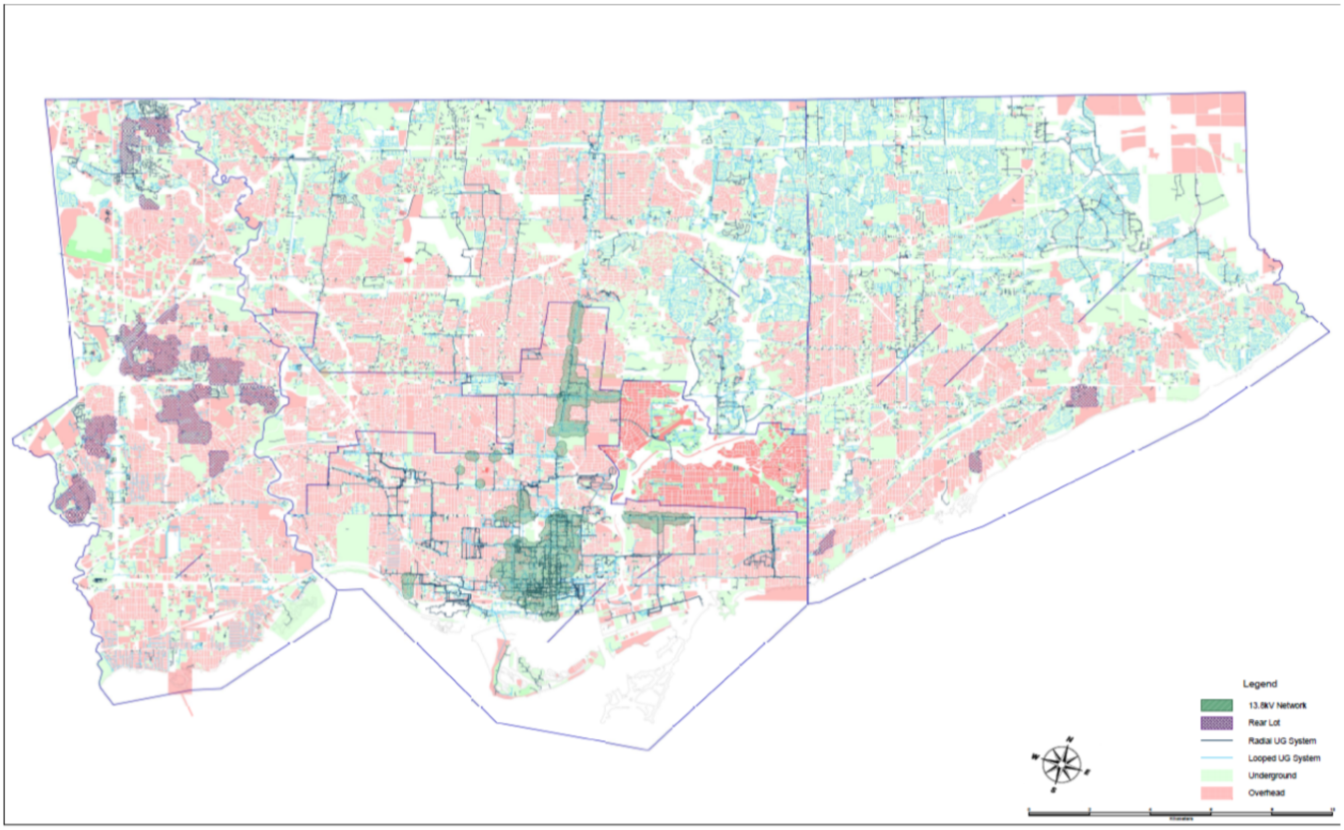
Dual radial systems are similar in design to radial feeders except that each customer is connected to two parallel radial feeders. The load is supplied by one of the radial feeders, as the other radial feeder remains on standby. In the case of a fault, the load is transferred from one feeder to the other by manipulating interrupter switches tying the two radial feeders together. Large commercial and industrial customers, as well as Toronto Hydro municipal stations and several older Toronto Transit Commission (TTC) stations are typically served by dual radial systems. A compact loop system is similar in configuration to a dual radial system, but is employed where space is more limited (e.g. in existing vaults).

In closed loop systems, customers are supplied by multiple feeders, and are fed via several redundant transformers and network protectors. If one feeder goes out, the customer can be supplied by another feeder. Closed loop systems are advantageous because under single contingency conditions, customers experience no power interruptions (Toronto Hydro, 2007). Only Toronto Hydro's 13.8 kV network system is a closed loop system.

[9] This total may vary depending on how feeder branches and sub-branches are counted.
[10] Single contingency condition or N-1 represents the condition where all electrical equipment is in service except one element. For example, if a substation has two power transformers, but one of them is out of service, the condition is called "N-1". The condition "N-1" generally occurs after a major disturbance causes equipment to trip and go-offline.

Figure 2-7**Error! Reference source not found.** shows the distribution of feeder types across the city. The 13.8 kV network, represented in dark green, is mostly concentrated in downtown Toronto (downtown core and the Yonge Street and Bloor Street corridors), while the other feeder types can be found across the city.

Figure 2-7 Location of Feeders, by Type



Source: Toronto Hydro

<u>Typical equipment</u>

For all underground feeders

The distribution transformer station of underground feeder systems can be classified according to one of three types:

- Vault type: The vault transformer can be small and located just below ground for single phase clients, or large and deeper underground for clients requiring larger, three-phase power supplies. Some vault type transformers can be located above ground inside a building. The equipment located in vault type enclosures cannot operate if the vault is flooded.
- Submersible type: They are designed similarly to the vault type transformer stations but the equipment is designed to operate when submersed. For example, submersible transformers are capable of continuous unattended operation while completely submerged under a head of 3 m of water over the top of the tank (IEEE Std C57.12.24, 2009, p. 3). They are currently the preferred design due to their submersibility.
- Padmount type: The padmount transformer is located on ground level in a metal-clad enclosure.

Underground feeder equipment typically consists of the following:

- Cables: The cables used in underground systems are generally insulated with cross-linked polyethylene (XLPE) or a paper insulated lead cover (PILC). The PILC cables also contain oil
- Pilot wire: For large and sensitive customers

- Fault circuit indicators
- Power transformers modules:
  - Load-break switch modules: Metal enclosed, air insulated, Vacuum or SF6 arc extinction, motorized or manual;
  - Fuse modules: Metal enclosed, air insulated, electronic fuses or SF6 power fuses or current limiting fused;
  - Power transformer : Oil type (most), dry type (in above grade vaults) or some used FR3 fluid (environmental friendly);
  - Elbows: cable connections to power transformers.
- Specifically for the network system, typical equipment consists of the following:Primary feeders;
- Network Units;
  - Primary Switch – Embedded in power transformer;
  - N/W Transformer: dry type;
  - N/W Protector: Breaker, back-up fuse, relays, current transformers, cable limiter.
- LV secondary network grid or spot networks;
- Except for the old network protectors, all network unit equipment are submersible.

For overhead, open loop and radial feeders:

- Poles: See civil categories below;
- Distribution transformers : ONAN (Oil Natural Air Natural) system;
- Gang-operated switches, single-phase switches or SCADA switches;
- Load interrupting switches;
- Fuse disconnecting switches;
- Conductors: “tree proof” protected aluminium (AL) conductors, steel reinforced aluminium conductors (ACSR), aluminium conductors (no tree proof protection), and copper (CU, legacy);
- Voltage Regulators;
- Circuit-breakers with reclosers;
- Capacitors;
- Insulators: made from porcelain (approximately half of all installed insulators) and polymer material (porcelain insulators are being progressively replaced by polymer insulators).

2.5 Communications Systems

The communications systems support the control and protection of electrical equipment. They are divided between protection and control systems, and the SCADA system.

For power lines, the distribution switch automation is generally limited to the 27.6 kV systems (Toronto Hydro, 2007).

Protection and control systems

The protection and control systems are located inside control buildings. Except for batteries, they are located in a temperature controlled room. Batteries at some stations in the Former Toronto area are currently located in the basement of buildings. However, Toronto Hydro expects to relocate these battery assets above grade by the 2030’s in order to help reduce flooding threats.

Typical electrical equipment

- Relays:
- Fuse, Load-break Switch, Circuit Breaker;
- Batteries;
- Auxiliary systems: cranes, fire alarm systems, air compressors, etc.

SCADA system

The supervisory control and data acquisition (SCADA) system is an automated system to remotely control equipment and gather operating information about electrical equipment.

Typical electrical equipment

- SCADA Switch;
- Battery;
- The remote terminal unit (RTU);
- Fault Detector;
- Fiber optic conductor;
- Motorized cell interrupter.

2.6 Civil Structures

The civil structures house or provide structural support for all electrical equipment. They are found in transmission and municipal stations, and all underground and overhead feeder systems.

As a general rule of thumb, civil structures are generally older in the Former Toronto than in the horseshoe area. Older structures (before 1970) may be more susceptible to climate impacts due to their degradation (wood rotting, corrosion of steel) and lack of reinforcement in concrete and design loads.

Typical equipment

For transmission and municipal stations:

- Gantry Towers;
- Exit lines;
- Equipment supports;
- Building: for indoor stations.

For underground feeders and transformer stations:

- Reinforced concrete cable chambers;
- Concrete vaults;
- Underground cable ducts.

For overhead feeders:

- In 2014, there were approximately 176,000 poles in Toronto Hydro’s electrical distribution system. The types of poles by construction material are approximately distributed as follows :
    - Concrete : 36%;
    - Aluminum: 2%;
    - Steel: 4%;
    - Cedar Poles : 58%;
    - Fiber glass: Negligible.
    - Iron: Negligible.
- Conductors and hardware (e.g. supports, bolts, etc.);
- Concrete footings (for steel, aluminium, concrete and some wood poles).

2.7 Auxiliary mechanical

Ventilation

All vaults have passive ventilation i.e. natural ventilation through slot openings in cover grates.

Drainage system

Toronto Hydro drainage systems can generally be divided according to the two types of vaults in which they are found:

- Small, shallow single phase sub vaults: do not contain pumps. These vaults' drains are connected to the city's sewer or storm sewer system and drain naturally. These vaults are also being fitted with automatic Petro plugs which stop drainage when oil is detected in the flow (equipment or other pollutant source) in order to prevent oil leaks into the sewer.
- Big deep vaults for Network, URD feeders: most of these kinds of vaults are equipped with mechanical pumps as they are located at a significant depth below grade and often below city sewers. Drains are installed in the walls of the vault and pumps are used to force water into the city's sewer systems. Approximately 10 % of network, URD vaults have drains without pumps (i.e. gravity driven natural drainage).

Sump pump

In 2014, approximately 1600 vaults out of 14,937 vaults had sump pumps (11%) (Toronto Hydro, 2014e). Toronto Hydro estimates that by the 2030's, these sumps will have oil sensing traps that will close if oil (equipment or other pollutant source) is detected.

2.8 Human Resources

Toronto Hydro has approximately 1,500 employees comprised of certified tradespeople, engineers and management professionals (Toronto Hydro, 2012). Employees who are involved in the operation of the electrical distribution system include supervisors and field crews for overhead, underground and network systems, control room staff, call centre workers and dispatchers. Toronto Hydro staff also includes the management team, engineers, asset management specialists and electrical system designers.

Weather can generally affect human resources in two ways. Adverse weather events can affect travel conditions on the journey to and from work for all employees. Furthermore, adverse weather events can affect the working conditions for field crews and field supervisors who need to access, operate or work on equipment across the city. Toronto Hydro strives to ensure a safe working environment for its employees, and has occupational health and safety policies and procedures in place that conform with the international occupational health and safety management system specification OHSAS 18001. These policies and procedures are complemented by the professional judgement of its workers as to whether conditions are safe enough to access outdoor equipment.

2.9 Time Horizon

The evaluation was carried out for the study period (2015 to 2050), but with specific focus on the possible state of the electrical system at the 2030's and 2050's time horizons. For example, this study considered changes to infrastructure systems based on current practices, trends and policy directions (e.g. transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[11], replacement of

[11] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. However, system vulnerability was judged based on climate change stresses, as it was assumed that gradual population growth would be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

non-submersible equipment). Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff were all used to help identify and describe the potential changes to assets at the 2030’s and 2050’s time horizon. The probability of a climate parameter occurring during the study period and on an annual basis for the 2030’s and 2050’s was also determined (see next chapter for further details).

2.10 Other Potential Changes that May Affect Infrastructure

2.10.1 Dependencies on Hydro One Infrastructure

Toronto Hydro is part of an interdependent electrical system that is reliant on infrastructure facilities that generate electricity, transmission systems that transport electricity over long distance, and transformer stations that convert voltages for transport and use. The electrical generation and transmission supply infrastructure on which Toronto Hydro relies upon can also be vulnerable to the impacts of a changing climate, and are owned by other electrical companies and organizations in Ontario. Therefore, it is important to note that the vulnerability of Toronto Hydro is therefore also tied to the vulnerability of these supply side infrastructure.

It should also be noted that in the event of a power outage, certain facilities and dependent infrastructure can be supplied by temporary, backup power generators (such as diesel or natural gas generators). In some cases, homeowners may be equipped with photo-voltaic cells that may be able to provide some power in the event of an outage. However, these forms of dispersed generation are specific to facilities and individuals, and not sufficient to meet the demands of larger portions of the population. Dispersed generation does not currently provide sufficient capacity to alleviate Toronto Hydro of its dependence on the large scale electrical generation and transmission supply infrastructure.

Most of the 230 kV, 115 kV and 27.6 kV station equipment that tie Hydro One transmission infrastructure to Toronto Hydro are owned by Hydro One, except for the 27.6 kV breakers at the transmission stations supplying the former North York area and the Cavanagh transmission station, which is totally owned by Toronto Hydro. In general, Toronto Hydro owns the 13.8 kV switchgear equipment. Toronto Hydro and Hydro One share a common Transmission Connection Agreement (Toronto Hydro, 2007).

2.10.2 Load Projections

Electrical load or demand is a significant factor in the operation of transmission stations. Demand is influenced by a variety of factors, including population size, types of uses (e.g. residential, commercial, industrial, institutional, infrastructure), time of day (e.g. peak, off-peak, night time), as well as daily temperature (e.g. heating, cooling).

For the present study, the projections of electrical load on each of the main transmission stations serving the City of Toronto were completed, and are shown in the next table. The methodology used by Toronto Hydro to calculate the projected load for the 2030’s and 2050’s is described in **Appendix F**. Major future load demand, added transmission station added capacity (i.e. growth), and proposed load transfers[12] were considered by Toronto Hydro.

[12] Load transfer represents the capability to discharge some load from one station to another transmission station. In case of an outage or a very high demand, the loss of supply, or requirement for additional electricity can be provided by another location. Some transmission stations have higher transfer capabilities than others due to higher installed capacity and/or lower demand. However, this capability changes with time: the increasing demand can lessen this flexibility, while investments in new additional capacity can increase the station capability.

Table 2-2 Load Projections by Transmission Station

Service Area *(Voltage step down)*	Number of Stations	Projected load (2030's)[13]	Projected load (2050's)
Former Toronto			
Downtown core *(115 kV/13.8 kV)*	6	86-95%	>95%
Downtown outer *(115/13.8 kV, 230/115 kV,115/27.6 kV)*	2	70-85%	>95%
	6	86-95%	
	3	>95%	
Horseshoe			
North Stations *(230/27.6 kV)*	1	86-95%	>100%
	1		86-95%
East *(230 kV/27.6 kV, 230/115 kV)*	1	<70%	70-85%
	2	<70%	86-95%
	3	70-85%	86-95%
	2	86-95%	86-95%
	1	86-95%	>100%
	1	>100%	>100%
Northwest *(230 kV/27.6 kV)*	2	70-85%	>100%
	1	86-95%	86-95%
	1	<70%	86-95%
Southwest *(230/27.6 kV,230/115 kV)*	2	86-95%	>100%

2.11 Data Sufficiency

The general characteristics of the systems under review were adequate for the purpose of this exercise, although it should be noted that no site visit was conducted in the project. Chapter 7 contains recommendations about further work that can be used to enhance the analysis of electrical system performance and sensitivities to climate related stresses.

[13] Note that Toronto Hydro considers 95 % as the max station load capacity in former Toronto area. This is because there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. When a former Toronto area station achieves 95% of its capacity, it signals to Toronto Hydro that a station load relief project is required. In the horseshoe area, station max capacity is considered to be 100% max load capacity, as there are existing station ties available to allow the transfer of feeder loads from one station to another.

3 Assessment of Climate Changes

This chapter describes how the climate data used in this study was developed. This work involved three activities, the identification of climate parameters, the estimation of the historical and future probability of occurrence of climate parameters, and the conversion of probabilities into PIEVC scoring to support the risk assessment. The results of this work are summarized in a table at the end of this chapter (Table 3-2). **Appendix B** and **C** support this chapter, providing additional background information on the methods, information sources and assumptions. The climate work was principally conducted by Risk Sciences International in collaboration with AECOM.

3.1 Climate Data Development Methodology

The development of climate data to support this study involved three main activities.

- First, climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected were identified (i.e. climate parameters);
- Next, the probability of occurrence of each climate parameter was estimated for future climates; and,
- Finally, the probability information of climate parameters was converted into the PIEVC seven point scoring scale to support the risk assessment.

3.1.1 Identification of Climate Parameters

The identification of relevant climate parameters and infrastructure impact thresholds was an iterative process involving a combination of three methods:

- Literature review of design loads in codes, standards and published literature;
- Practitioner consultation, including targeted interviews, email communications, and workshops; and,
- Forensic analyses of either system specific case studies or relevant cases in the published and grey literature.

While these methods were employed during Phase I, they were expanded significantly and updated for Phase 2. The list of climate parameters from Phase 1 of this study was revisited through practitioner consultations (i.e. workshops), and a more thorough forensic analysis process was conducted using newly available impacts data provided by Toronto Hydro. Literature, including the Institute of Electrical and Electronics Engineers (IEEE) and CSA standards, was reviewed by both RSI and AECOM research team members, yielding more specific design thresholds and criteria. Further information about these techniques can be found in **Appendix B.**

3.1.2 Estimating the Probability of Occurrence of Climate Parameters

To estimate the probability of occurrence of climate parameters over the study period, their probability of occurrence was first established for historical climates. Future conditions cannot be well understood until current and historical climate conditions are quantified, particularly with regards to already existing vulnerabilities and thresholds present within the distribution system. This historical information was combined with climate projections from an ensemble of global climate models through the application of the “Delta-method” (see description on next page) to obtain estimates of the probability of occurrence for climate parameters. Additional complementary estimation techniques (i.e. regional climate models, statistical downscaling, climate analogues) were also employed to evaluate several complex climate events (e.g. freezing rain, ice storms, high intensity rainfall, lightning, tornadoes), as well as to validate or refine the results obtained from the “Delta-method” approach. These tasks are summarized in the following section while more details can be found in **Appendix B**.

Establishing Historical Climate Baseline

The probability of occurrence of climate parameters under historical climate conditions was established in Phase I of this study. Phase 2 reviewed and further refined them in order to serve as a baseline for climate change projections.

Historical climate conditions were established based on Environment Canada's climate station network, the most reliable and highest quality long-term climate record in Canada. While there are numerous climate stations in and around the City of Toronto, detailed hourly weather data are usually only available from airport locations. Thus, the majority of historical climate information used in this analysis is based on records from Pearson International Airport, with further contributions from Buttonville and Toronto Island Airports. Toronto is also the location of the climate station with the longest period of record in Canada, located at its City Centre location, a separate site which provided further perspective on longer term historical climate.

In the case of extreme, very localized, or complex climate events (e.g. tornadoes, freezing rain, ice storms, lightning storms), authors employed alternative methods (e.g. using averaging periods greater than 30 years) or consulted alternative data sets (e.g. the historical tornado database) to establish a historical baseline because this information was not directly available from weather station data.

Future Projections

The climate projection data which serves as a basis for this study was sourced principally from global climate models (GCMs). The latest International Panel on Climate Change (IPCC) 5th Assessment Report (AR5) provided results from 40 GCMs, produced and operated by modeling centres from around the globe. These models provide many of the basic parameters used in developing projections, as well as providing the "boundary conditions" for more detailed assessments, such as downscaling studies. The availability of multiple models also allows for the use of climate model "ensembles," which use multiple models for the development of projections, rather than employing the results of a single model which may contain biases affecting the accuracy of results. The use of ensembles is considered by the IPCC as a best practice for climate analyses, and therefore has been the dominant method used for climate projections in Phase 2.

GCMs require "emissions scenarios" as inputs for the calculation of climate projections. The latest IPCC AR5 has introduced a new method of describing future changes in emissions. Representative Concentration Pathways, or RCPs, describe explicitly the expected increase in energy generated by increases in greenhouse gases. The most pessimistic emissions scenario, RCP 8.5, indicates an increase of 8.5 watts per square meter of additional energy under future climate conditions. It is referred to as the "business as usual" emissions scenario, provides the best fit based on historical trends in global emissions, and was the scenario used for Phase 2. Further details on IPCC findings, GCMs, RCPs, and other aspects of climate change projections, can be found in **Appendix B.**

Applying the "Delta-Method"

Individual GCMs contain inherent biases when attempting to recreate historical climate, for example being either too cool or warm compared to historical averages. To compensate for this effect, the "Delta-method" was employed. First, GCMs were evaluated to determine changes from their own respective baselines. This difference between model baseline and projected conditions is then applied to the observed historical climate baseline. For example, if the GCM ensemble indicated an average increase of 2 degrees between the baseline period and the 2050's, and a given station shows an average annual temperature of 3°C, then the projected annual average temperature for that location for the 2050's becomes 5°C. This represents the "delta", or the change in climate parameter based on the difference projected by the GCM ensemble applied to historical baseline data.

Treatment of Complex Climate Events

To validate the results obtained from the GCM – "Delta-Method" for some of the climate parameters, three other complementary estimation techniques were also used, regional climate modeling, statistical downscaling techniques and climate analogues. Furthermore, some complex climate events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. tornadoes, freezing rain, ice storms, lightning). Use of these three complementary estimation techniques was necessary to develop projections for these kinds of climate parameters.

It should be noted, however, that even with the availability of specialized methods, there remain highly localized atmospheric events which cannot be projected with confidence, and the effects of climate change on these types of events are still being researched by the climate research community. See **Appendix B** for further discussion of developing projections for complex climate events.

Estimating the Probability of Occurrence of Climate parameters

The methodology used for determining climate parameter probabilities for Phase 2 was somewhat modified from standard PIEVC Protocol based studies. The Protocol (Engineers Canada, 2012) indicates that the probability of a climate parameter occurring should be based on the probability of occurrence during the *full* time period of the study, which is typically the life cycle and long-term planning considerations of the infrastructure under study. For Phase 2, a period of 35 years between 2015 and 2050 was chosen. However, in recognition that response to these hazards can include both asset hardening/replacement cycles (long-term measures) as well as maintenance and management considerations (short term measures), a second set of probabilities based on annual occurrence was also determined. Examining both annual and study period probabilities was useful for understanding vulnerabilities based on climate parameters that would occur on an annual basis (e.g. high temperature) against those which would occur less than annually, but with the potential to cause significant impacts sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes).

Annual probabilities are expressed as the number of occurrences per year for historical and (where available) projected estimates for the 2030's and 2050's, or more specifically for 30 year periods centred on those future decades. The so-called "study period" or "lifecycle" probability of occurrence is then expressed as a percentage (i.e. given those annual frequencies, what is the overall probability that an event will occur during the *entire 35 year time horizon*?).

The probability of occurrence of a climate parameter considered in this project is, in most cases, representative of a "point" probability (i.e. historical probability values based on measurements at a single location). However, the lightning and tornado climate parameters were also evaluated using different "target" sizes to illustrate the effects of changing this perspective, as well as to better correspond with field conditions and associated response. More detailed information about how the probabilities of individual climate parameters were determined can be found in **Appendix B**. The results of this work are listed in Table 3-2 at the end of this chapter.

3.1.3 Assigning a PIEVC Score to Climate parameter Probabilities

The probability of occurrence for climate parameters both annual and during the study period were converted into PIEVC probability scores (i.e. 0-7) for the risk assessment, following the quantitative "Method B" approach indicated in the Protocol (Engineers Canada, 2012) (see Table 3-1). For example, the annual probability of occurrence of high temperatures above 40°C was estimated to occur approximately 0.01 times per year in the historical period (last 100 years), or 1 % probability of occurring each year (PIEVC score 1). Similarly the annual probability for this parameter was 0.3 to 2 times per year for the 2030s, which signifies a 30 % to >100 % probability of occurring each year (PIEVC scores 4 to 7 respectively). This climate parameter is estimated to occur between 1 to 7 days per year by the 2050s, such the annual probability of occurrence is >100% (PIEVC score 7).

Table 3-1 PIEVC Version 10 Probability Scores based on Method B

Score	Probability	
0	< 0.1 %	< 1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	> 99 %	> 1 in 1.01

3.2 Summary of Results

24 climate parameters covering temperature, precipitation, wind and lightning hazards were considered within the climate analysis. However, four of them were not carried forward in the vulnerability assessment due to data availability issues or relevance[14]. Table 3-2 provides a summary of the climate data results. Relevant climate parameters and infrastructure thresholds (climate parameters) to be used in this study are listed. For these climate parameters, historical and future probabilities of occurrence, as well as PIEVC probability scores for annual and study period probabilities are presented.

Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%	7	7	7
	30°C	16 per year; **26 per year**, ***47 per year***	100%	7	7	7
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%	6	7	7
	40°C	~0.01 per year[15]; **0.3 to 2 days per year**, ***1-7 days per year***	~100%	1	4 - 7	7
High Daily Avg Temperature	30°C	0.07 per year[16]; **N/A**, ***1.2 days per year***	~100%	3	7	7
	35°C	*Zero* occurrences historically; ***zero occurrences projected***	0%	0	0	0
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%	6	7	7
High Night time Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year**, ***16 per year***	~100%	6	7	7
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected* ↑, *percentage unknown***	~75%-85%	2	3	6

[14] The climate parameters not evaluated in the vulnerability assessment were high daily average temperature above 35°C (relevance), 6 hr+ freezing rain (relevance, as no ice accretion threshold was known), Minor ice accretion and deicing agents (complex interaction, no projection data available) and tree growth, pest and disease (complex interaction, no data available).
[15] Based on data from Toronto City Center station rather than Pearson Airport.
[16] Based on 4 occurrences since 1961 at Pearson Airport; see discussion in text for further details.

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%	3	3	7
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%	2	3	7
	60 mm ≈ 30 mm radial	High Risk: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Low Risk: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%	0-1	0-1	2-4
	6 hours + freezing rain	0.65 days per year; **~0.75 per year, *~0.94 per year***	100%	5	6	7
High Winds	70 km/h+ (tree branches)	21 days per year***;* N/A, *24 to 26 per year***	100%	7	7	7
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%	7	7	7
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher	2	2	7
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%	0	0	1
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%	0	0	0
Lightning[17]	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)	Lg - 2 Sm - 0	n/a	Lg – 6 Sm - 3
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%	7	7	7
Complex Interactions	Minor ice accretion + deicing agents	***Projections unavailable***	N/A		N/A	
Complex Interactions	Changes in tree growth, disease conditions	***Projections unavailable***	N/A		N/A	

3.3 Data Sufficiency and Recommendations

The primary sources of information used in this climate data work were:

- Environment Canada Weather Station Data;
- IPCC AR5 quality controlled GCM output;
- TRCA environmental data and observations (TRCA 2014).

The climate data available for this study was judged to be sufficient to cover the majority of climate related stresses to electrical distribution systems (stemming from temperature, precipitation and wind). The study area of the City of Toronto also benefited from having good quality, long-term climate data that covered most areas of the city for these types of climate parameters. While further studies, in-depth analyses, and data quality improvements can be made (see Chapter 7), the climate data that was available was sufficient to support the risk assessment.

[17] Note that "Lg" and "Sm" refer to large and small transformer stations, see Appendix B for more details.

4 Vulnerability Assessment Methodology

The vulnerability of the electrical system to climate parameters was initially completed by employing a screening level risk based methodology (risk assessment) to identify low, medium and high risk interactions. The level of risk was evaluated based on the probability of occurrence of a climate parameter coupled with the severity (consequence) of the impact on the system and on electrical service provision. Low risk level interactions were generally judged as not being a significant issue for Toronto Hydro. Medium level risks were evaluated through a further engineering analysis to determine whether the interaction resulted in vulnerabilities (or part of a general pattern of vulnerability). Finally high risk level interactions were deemed as vulnerabilities for Toronto Hydro.

The general procedure for the risk assessment is described in Step 3 of the Protocol. However, study specific considerations (e.g. the *systems level approach*), adaptations and guidance for completing the risk assessment are described in the following chapter. Completion of the risk assessment follows the "Consultant Option" of the Protocol[18]. Notably in this option, AECOM completed the risk matrix through internal meetings with its own electrical engineers. This information was then validated with Toronto Hydro staff in a workshop held on October 10, 2014, at Toronto Hydro's offices.

4.1 Risk Tolerance Thresholds

The risk tolerance thresholds employed within this analysis conform with the proposed thresholds of the Protocol as given in the table below. These thresholds were validated with Toronto Hydro at the workshop.

Table 4-1 Risk Tolerance Thresholds

Risk Range	Threshold	Response
< 12	Low Risk	Monitoring or no further action necessary
12 – 36	Medium Risk	Vulnerability may be present. Action may be required, TBD through engineering analysis
> 36	High Risk	Vulnerability present, action required

4.2 Yes/No Analysis

The first consideration of the risk assessment is to identify whether a climate parameter will interact with the infrastructure system under consideration. A Yes/No analysis column for each of the 20 climate parameters is included in the risk assessment matrix presented in **Appendix D**. A "No (N)" result means that there is no interaction between the climate parameter and infrastructure system, while a "Yes (Y)" result means that there may be an interaction. The severity assessment is conducted only for "Yes" interactions.

4.3 Infrastructure Performance Responses - Systems Level Approach

As mentioned in the introduction, this study adopts a *systems level approach* to the analysis of climate change impacts on Toronto Hydro electrical distribution infrastructure due to the extensive, complex and interdependent nature of the electrical system. The severity of impact is evaluated based on the consequences of the interaction of different weather events with the systems and subsystems under study.

The relevant infrastructure performance responses remain the same as presented in the pilot case study. Notably, they are:

- Structural design - *Structural integrity, cracking, deformation, foundation anchoring, etc.*

[18] This approach, rather than the facilitated option, was adopted in this study because it was more efficient; the learnings gained from the pilot case study provided AECOM with the necessary insight to complete the risk assessment on its own prior to validation with Toronto Hydro.

- Functionality - *Effective load capacity, efficiency, etc.*
- Serviceability - *Ability to conduct maintenance or refurbishment, etc.*
- Operations, maintenance and materials performance - *Occupational safety, worksite access, operations and maintenance practices (frequency and type), etc.*
- Emergency Response - *Planning, access, response time*
- Insurance Considerations (Toronto Hydro perspective) - *claimable for repair, cause 3rd party payment, affect insurance rates*
- Policy and Procedure Considerations - *Planning, public sector, operations, maintenance policies and procedures, etc.*
- Health and Safety - *Injury, death, health and safety of Toronto Hydro employees, the public, etc.*
- Social Effects - *Use and enjoyment, access, commerce, damage to community assets (buildings), public perception, etc.*
- Environmental Effects - *Release or harm to natural systems (air, water, ground, flora, fauna)*

It is clear that within a *systems level approach*, weather interactions with infrastructure systems can solicit a range of different performance responses, as well as responses of differing degrees (i.e. intensity) from different components. In other words, some components within a system are more sensitive to certain types of weather events than others (e.g. heat affects the operation of transformers more than it affects the wooden pole on which the transformer is attached).

In order to conduct a logical, structured analysis, the proposed *systems level approach* identifies the infrastructure performance response stemming from the component (e.g. pole, transformer, power line, switch, etc.) which constitutes the weakest link in the system category for a given weather parameter. The component whose functionality, capacity, structural integrity or operation is affected or compromised the most, which in turn may cause other interdependent components or the entire system to cease to operate, fail, or lose capacity, constitutes the weakest link in the system. For example, the failure of a station power transformer due to high temperature and load may cut off electricity service, irrespective of what the heat may do to other equipment and structures. The station power transformer is thus considered to be the most sensitive and weakest link under high heat conditions.

As the primary role of Toronto Hydro's electrical distribution infrastructure is to provide electricity, one primary guiding criteria was used to determine which component(s) within the major systems categories constituted its weakest link: the component which, due to an interaction with a weather event, resulted in damage/failure of that component, which in turn compromised the ability of the system to deliver electricity to customers safely and securely. The risk assessment matrix presented in **Appendix D** contains a column named "consequence" which identifies the weakest link component and the anticipated infrastructure performance response.

4.3.1 Consideration of Redundancy and Station Capacity

While a component malfunction or failure may compromise the system's ability to provide electricity safely and securely, a *systems level approach* allows system design characteristics to mitigate this impact. Two notable characteristics of electrical systems are considered by this study: redundancy and station capacity.

Redundancy is the duplication of equipment and systems that afford an alternative way to deliver electrical services in the event of equipment damage or failure. In electrical systems, redundancy is provided through the presence of similar or identical equipment operating in parallel or kept on standby, and is a key component of essential infrastructure services such as electricity provision. Station capacity indicates that a station possesses capacity in excess of normal demand (i.e. under normal circumstances).

Redundancy and station capacity are characteristic of the different types of electrical systems under study. As redundancy and station capacity can mitigate component failures (i.e. allow systems to continue to provide electricity despite equipment failure in one area), they are used as mitigating factors which can attenuate severity scores. The explanation of how redundancy and station capacity are evaluated for each of the major systems categories is in presented in the sections below.

Transmission Stations

A station's ability to mitigate the system's vulnerability to climate is most usefully considered with respect to high temperatures. During high temperatures, stations with greater excess capacity will be able to continue to supply electricity despite increased demand, while stations with less excess capacity may have to reduce demand (e.g. shed load through temporary forced outages) in order to operate station equipment acceptably (e.g. to avoid overheat and burnout).

Transmission station capacity is based on the load projection exercise completed by Toronto Hydro for this project. This study is briefly described in **Appendix F (**Also see Chapter 2, *Load projections*, for more information). Station capacity is rated as low or good based on the load cut-offs shown in the table below. If the station capacity is rated as low by the end of the study period (2050's), its severity evaluation for high temperature parameters is increased by ''+1''.

It is possible that excess station capacity can also be considered as a mitigating factor in the event of freezing rain, flooding, high winds, etc. For example, if a high wind event causes flying debris to damage an outdoor station, an adjacent station can help by picking up some of the load. In this case, it is the capacity of adjacent stations which helps determine the vulnerability of a service area. In the horseshoe area, station and feeder ties between service areas allow some of the load to be transferred[19]. However, this factor is not considered in the present study because adjacent stations can only take on a small portion of a faulted station's load (i.e. no station is designed to take the full load of an adjacent station, otherwise it would be overdesigned), nor are there sufficient feeder or station ties to allow the complete transfer of the load. Thus, large portions of a service area may still be susceptible to an outage at its transmission station in spite of the fact that an adjacent station has excess capacity.

Table 4-2 Severity Rating Based on Station Capacity by the 2050's

Severity Rating	Station Projected Load by the 2050's
Low (+1)	≥ 95 % (Toronto) and ≥100% Horseshoe Area
Good (no change)	< 95 %

Municipal Stations

The redundancy of the municipal stations is based on geography, and only considered for high temperature parameters for the same reasons as listed above under transmission stations. According to Toronto Hydro, if a municipal station is located in the Former Toronto area, it is generally considered that the station has less transfer capability than a station located in the horseshoe area. Severity ratings for all municipal stations in the Former Toronto area are increased by ''+1'' to reflect the low station transfer capacity in the event of a problem. This severity increase for former Toronto area municipal stations does not apply to other climate events such as freezing rain or wind because these stations are generally located indoors in the Former Toronto area.

The Toronto Hydro to Private ownership stations are dedicated to the owner. There are no transfer capacities to another station. A ''+1'' is added to the severity rating for high temperature parameters.

[19] Recall that at present, there are no station ties between station service areas in the Former Toronto area. The addition of station ties in this area is constrained by the fact that infrastructure is older, located in a dense built urban environment, and generally underground. At present, Toronto Hydro is considering the addition of station ties in the Former Toronto area, but this is not considered in this risk assessment due to its preliminary nature of this idea. In the horseshoe area, station ties allow stations to provide some load relief to adjacent service areas when required.

Underground Feeders

The redundancy of the underground feeders is based on the configuration of the feeder and its location in the city. Dual radial and residential feeders in the Former Toronto area are considered to have the lowest redundancy and capacity because structures are older, more stressed by higher loads, and are installed with less space between the conductors. The arrangement of the conductors is important because the ampacity of conductors are sensitive to the heat generated by nearby conductors. Severity ratings for these feeders are increased by ''+1'' as a result (Table 4-3).

Table 4-3 Severity Rating Based on Feeder Configuration

Severity Rating	Increasing Levels of Feeder Redundancy
Low (+1)	Dual Radial & URD : Former Toronto
Moderate (no change)	Dual Radial & URD : Horseshoe
Good (no change)	Compact Loop Design
Best (no change)	Network

Overhead Feeders

The redundancy of the overhead feeders is considered between two configurations: radial or loop. Radial lines cannot be backed-up in the event of a fault, while loop configurations could allow electricity to be brought in through the “other side” of the loop. For this purpose, the severity ratings for radial feeder configurations are increased by ''+1''.

Communications Systems

The redundancy evaluation is not considered for the communications systems, as they do not mitigate circumstances of loss of electrical service provision.

Civil Structures

Historically, infrastructure built for the distribution of electricity in the City of Toronto were concentrated in the downtown core and inner city and later extended to the horseshoe area. Part of the electrical equipment was replaced over time but much of the civil structures (e.g. underground vaults) remain in place due to their expected lifespan (35 - 60 years). It is thus assumed that the civil structures in the Former Toronto area are older and more degraded than the structures in the Horseshoe Area. A ''+1'' severity scoring is added to the Former Toronto civil structures.

4.4 Scoring Severity

The severity scoring exercise is conducted using the scoring scale defined by the Protocol, method D. Examples of impacts on different equipment were developed in the course of this analysis. In addition to the guidance provided by the Protocol on severity scoring, this study provides a further, electrical system specific consideration in severity scoring. Two complementary, severity scoring scales were developed for this study to reflect the severity scoring differences between stations and feeder systems. As stations represent major nodes in the distribution of electricity, an affected or disabled station could result in a loss of service on all downstream feeder systems and customers. However, if a feeder branch or sub-branch is affected, only the customers on the branch or sub-branch may be affected. Thus, the impacts on station equipment are judged to be more severe than impacts on feeder systems. The severity scoring scale employed in this study, as presented below, reflects this general consideration.

Table 4-4 Severity Scoring Scale for Electrical Distribution Systems

Score	Stations			Feeders	
	Method D	**Descriptive**	**Examples**	**Descriptive**	**Example**
0	No Effect	Negligible or N/A		Negligible or N/A	
1	Measurable	Very Low - Some measurable change		Some loss of serviceability & capacity, no loss of function	*Arrestor failure, overheating cables, salt deterioration of civil/electrical equipment*
2	Minor	Low - Slight loss of serviceability	*Station battery – lifespan shortened*	Some loss of capacity & function	*Overheating transformer from high load*
3	Moderate	Moderate loss of serviceability, some loss of capacity, but no loss of function	*Station transformer heating up, but possibility of meeting demand from another station*	Moderate loss of function	*Broken spring in underground switchgear, distribution transformer out (must replace), cable*
4	Major	Major loss of serviceability, some loss of capacity & function	*Station transformer heating up, need to do load shedding*	Major loss of function of multiple equipment – localized	*Transformer and switchgear out (replace multiple equipment)*
5	Serious	More loss of capacity & function	*Station transformer heating up, need to do load shedding for longer duration*	Major loss of function of multiple equipment – wide area	*Transformer and Switchgear out Flooded vault that cannot be pumped*
6	Hazardous	Major - Loss of Function	*Loss of CT/VT transformer, battery assets*	Major loss of function of multiple equipment – wide area	*Leaning pole/downed line*
7	Catastrophic	Extreme – Loss of Asset	*Station trans. failure*	Major loss of function of multiple equipment – wide area	*Downed pole, line and transformer*

4.5 Mapping Risks

Due to the sheer number of similar assets and their distribution across the city, study authors and Toronto Hydro have elected to map climate change risks to the electrical distribution system in the City of Toronto. It was decided that two main asset classes would be included in the risk map: stations and feeders. The risks to supporting infrastructure, such as communication systems and civil structures, were difficult to represent on such a large scale. Furthermore, the risks to these systems are generally associated with, and can be adequately illustrated by, the risks to the stations and feeder systems.

The risk mapping exercise was completed using the geographic information systems (GIS) resources provided by Toronto Hydro. AECOM provided the final risk assessment matrix results to Toronto Hydro's GIS team. Each of the station and feeder assets in the risk assessment matrix were identified on GIS maps. Stations were illustrated as polygons representing the stations' service areas rather than as points where stations are located. This was done in order to illustrate the fact that faults at a station can affect an entire service area. Feeder systems were illustrated as line vectors on the map. Next, the low, medium or high classification of station or feeder risks were represented by colouring the assets class representations (polygons or lines) in yellow, orange or red to denote low, medium and high risks respectively. Where there were no interactions between climate and infrastructure, asset representations were coloured in grey. Finally, white spaces within the City of Toronto generally indicate where no electrical service is provided. Results of the risk mapping exercise are presented in Chapter 5 and in **Appendix E**.

5 Assessment Results

This chapter presents a summary of anticipated impacts from the interaction of climate events with electrical distribution system infrastructure resulting in low, medium and high risk interactions. In addition, special case risks are also presented.

5.1 Low Risk Interactions

High Temperature

SCADA systems may be affected by ambient air temperatures above 40°C. According to equipment design specifications (S&C manufacturer, 2011), such temperatures constitute unusual conditions for the interrupters within the SCADA system. At high temperatures over 40°C, the accuracy of power line current and voltage sensors, as well as the ability to provide DC voltages for the control of the switch, are not assured. SCADA system equipment are tested to operate between -40°C to +40°C. However, other components of the SCADA system like the communication and control unit can operate at temperatures up to +70°C. A low risk score was given considering that the SCADA switch is able to operate in temperatures above 40°C, but its performance (accuracy of sensors) may decrease.

Extreme Rainfall

Extreme rainfall poses a low risk to certain underground feeder systems in the horseshoe area. Underground feeder systems with some equipment located in above ground vaults or on padmounts may be affected by localized flooding due to extremely rainfall. This creates an issue in terms of accessing equipment.

Some transmission stations in the Former Toronto area currently have batteries and switchgear located below grade. This equipment could be damaged if flooding occurred. Toronto Hydro is currently moving its battery assets above grade when they reach the end of their lifecycle (typically 10 – 12 years). By the 2030's, it is expected that all station batteries will be moved above grade. Some of the switchgear equipment will also be moved above grade, although stations in the Former Toronto area may face space constraints to moving all equipment above grade. As such, it is likely that some switchgear will still be located below grade by the 2030s. However, stations are equipped with multiple sump pumps which can evacuate water that flows into the basements. According to a Toronto Hydro representative, there have been no flooding incidents to Toronto Hydro stations owing to heavy precipitation over the last several decades due to the pump and drainage systems found in stations. Based on expected work to relocate batteries and certain switchgear, and continued adequacy of sump pumps, the risk of flooding from extreme rainfall for transmission stations in the Former Toronto area was rated as a low risk.

Freezing Rain

For stations, 15 mm or less of freezing rain are not expected to create sufficient ice loads to cause structural problems. Freezing rain could cause some delays in accessing equipment (e.g. ground or equipment encrusted with a layer of ice), although this was judged to be of low risk by workshop participants

Snow

Snow accumulation and snow fall, especially for days with >10 cm of snow, can also cause visibility and access issues. Access to padmounted transformers and switches, as well as underground vaults may be hampered by snow pushed aside from road and sidewalk snow clearing equipment, thereby lengthening the time needed to access equipment. However, access issues from snow were judged to be of low risk by workshop participants.

Frost

Frost may cause the displacement of the ground (frost heave) and compromise the stability of the foundations of poles, vaults and cable chambers. Frost heave events are generally localized, and do not tend to disrupt electrical service. Furthermore, the number of frost free days are expected to increase by 2050 due to increases in annual temperatures. For these reasons, frost was judged to be of low risk. Civil structures located in the former Toronto area were given a slightly higher (+1) severity rating (and therefore risk rating) because the infrastructure is generally older than those found in the horseshoe area.

5.2 Medium Risk Interactions

High Temperature

High ambient air temperatures starting at 25°C and above are responsible for the majority of medium risks evaluated within this study. Unless stated, the temperatures presented below exclude consideration of humidity on felt temperature (i.e. humidex). From an electrical equipment point of view, it is the ambient air temperature, not humidity, which impacts the structural integrity or lifespan of equipment. Humidity, coupled with high ambient air temperatures may result in higher felt temperatures by people, which in turn can increase the demand for air-conditioning. However, risks posed by high temperatures to infrastructure are evaluated in terms of their design and performance characteristics (ability to shed heat or cool down), which are not affected by humidity levels. High humidity was considered when evaluating the risks to Toronto Hydro personnel.

High temperatures affect the lifespan of station batteries. Where the air temperature of rooms that house station batteries exceeds 25°C, the lifespan of the batteries will begin to degrade. This will result in the long-term in the replacement of batteries sooner than expected. The buildings containing the rooms where batteries are stored afford some protection from changes to external air temperatures. This means that an external air temperature of 25°C may not immediately trigger the premature degradation of batteries. However, rooms where batteries are stored are not temperature regulated, and the impacts to battery lifespan will increase as external air temperatures increase above 25°C. Heat impacts on station battery lifespan were judged to be of medium risk.

As maximum daily air temperatures exceed 35°C, station power transformers will be the most critical pieces of equipment to be affected. First, the use of air-conditioning will increase, thereby increasing the electrical load on transformers. Transformers will heat up, but warm ambient air temperatures also reduce the effectiveness of natural or mechanical cooling. Stations with low projected excess capacities by the 2030's and 2050's will be less able to meet additional demand during periods of high temperature because of higher existing base load. These include transmission stations located in downtown areas, as well as Bathurst station, Sheppard, Leaside, Rexdale, Woodbridge, Manby and Horner. These were judged to be slightly more at risk (+1 severity) as compared to other stations in the East and Northwest sub-service areas.

Heat waves, when the daily maximum temperature during three consecutive days exceeds 30°C, as well as warm nights (minimum temperatures ≥ 23°C) both constitute medium risks for station power transformers. High night time temperatures will result in continued electrical use for air-conditioning, and also decrease the potential for transformers to cool down overnight. However, overall electrical demand is lower at night than during the daytime, and Toronto Hydro staff did not consider high night time temperatures to be as significant a concern as high daytime temperatures or heat waves from an electrical system point of view (Workshop 2).

High temperatures above 40°C, average temperatures over 30°C on a 24h basis, heat waves and high night time temperatures were also judged to be a medium risk for underground and overhead feeder systems due to high electrical demand for cooling and high ambient temperatures. Cables and power transformers were the two most vulnerable parts of these feeder systems in terms of heat. Under high demand, underground conducting wires and their housing undergo thermal expansion. This affects the structural integrity of the housing by causing wear and potentially leading to microfractures that are susceptible to water infiltration. Underground cables laid in close proximity or side by side, as is the case for underground feeders in the denser Former Toronto area, are also more susceptible to these expansion effects than underground feeders in the horseshoe area. Adjacent cables tend to heat one another up, and the increased heat reduces the cables' electrical transmission capacity. In overhead systems, cables under high demand will also lead to cable expansion and conductor sag. While this sag is generally accounted for in tree trimming and object clearance around power lines, excessive sag may be more prone to contacting objects and causing an electrical fault.

Feeder system power transformers are affected in a similar manner as their station counterparts. High ambient temperatures place additional demand from air-conditioning on transformers, while also affecting their ability to effectively cool. Overheating overhead transformers may fail or catch fire and will have to be replaced. In terms of relative risk, it should be noted that an overheating feeder line power transformer is less critical than an overheating station transformer, as the former serves fewer clients than the latter.

Underground dual radial, URD, compact loop and network systems afford increasing levels of redundancy for clients, due to their ability to supply electricity in the event of an outage through a different branch, loop or conduit of the feeder system. In this study, dual radial and URD feeders in the Former Toronto area were considered to be less able to cope with high electrical demand and mitigate outages than similar electrical feeder types in the horseshoe area. This is due to the fact that feeders in the Former Toronto area are already under high base load (denser environment), their equipment is generally older and cables running side by side increase the heat load and reduce their maximum capacity. Therefore, underground feeders in the Former Toronto area are considered to be slightly more at risk (+1 severity) to heat impacts as compared with similar feeder types in the horseshoe area.

Overhead feeder systems were judged to be slightly more at risk (+1 to +2 severity) than underground systems to temperatures above 40°C and to average temperatures above 30°C on a 24h basis. While electrical load demands may be similar for underground and overhead transformers, direct solar radiation and exposure to high ambient air temperatures can reduce the ability of overhead transformers to disperse heat. On the other hand, overhead transformers were judged to be less vulnerable to high night time temperatures than underground systems, due to increased circulation of cooler nighttime air around overhead transformers as compared to those located in underground vaults.

High ambient air temperatures were also judged to be medium-low risks for protection and control systems. Like station batteries, high temperatures will degrade the expected lifespan of batteries used to power the feeder protection and control systems in the event of a power failure.

Extreme Rainfall

The most significant medium risks from extreme rainfall events are related to the flooding of non-submersible vault-type electrical components kept below grade. Vaults below grade are usually equipped with either passive drainage systems or active pumping drainage systems to keep them from flooding. However, under extreme rainfall conditions, it is possible that the sewers to which these drainage systems are connected may themselves be at capacity, and without the ability to evacuate the water, some vaults may flood. In flooded vaults, non-submersible electrical equipment could be damaged, and an outage may occur. This is also a concern in some network type feeders in downtown Toronto, where old network protection equipment are not housed in submersible enclosures. Toronto Hydro is gradually installing submersible equipment in all below-grade vaults, but non-submersible equipment is still expected to be in present by the end of the study period. Furthermore, the equipment in flooded vaults cannot be accessed until the water is evacuated, creating a delay in responding to electrical incidents.

While not exclusively a problem related to heavy rainfall events, water infiltration into the ground and moisture around underground cables can lead to water treeing[20] and cracking of cable insulation. Deterioration of cable housing could lead to electrical faults if cracks become sufficiently large to allow ground moisture to serve as a pathway for electricity to ground.

[20] Tears in the cable's insulating layer caused by the presence of moisture and an alternating current's (AC) electric field.

It was noted in the workshop that extreme rainfall can be beneficial to overhead feeder systems. Salt residues from the wintertime and dust throughout the year can accumulate on electrical insulators. Moist conditions such as fog, mist or light rainfall can cause these accumulations to serve as conduits to ground, causing flashovers and potential pole fires and outages. Heavy rainfall events, especially in the early spring, are in fact beneficial for washing off the salt and dirt residues from insulators. Note that 27.6 kV and 13.8 kV lines are more prone to flashovers due to their higher voltages. It was noted in the workshop that 27.6 kV systems in particular may require more frequent cleaning than is currently the case in order to prevent flashovers, while flashovers do not tend to occur with 4.16 kV equipment.

High Winds

High winds over 70 km/h (but less than 90 km/h) were considered a medium risk to overhead power lines. While lines and poles are designed to withstand such wind speeds, it has been found that tree branches may begin to break at these thresholds and fall onto lines. Overhead conductors may also flail in the wind and contact branches. At the least, these tree contacts may cause momentary interruptions to electrical service. At the worst, tree branches and limbs may fall on and damage or sever power lines, potentially causing outages, fires and public safety hazards.

Lightning

Lightning strikes on overhead feeder systems was rated as a medium risk. Lightning arrestors installed on overhead power lines are designed to direct lightning surge currents to ground and protect pole mounted equipment such as transformers, switches and SCADA equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially lead to a localized outage.

Human Resources

Most of the human resource interactions with climate parameters (high heat, heavy precipitation, 15 mm of freezing rain, high wind, tornadoes, lightning and snowfall) were judged to be of medium risk. High heat conditions can make it dangerous to work on outdoor and overhead equipment for extended periods of time. For underground systems, high ambient temperatures can exacerbate hot conditions in vaults (heated by transformer operation), thereby also making it unsafe to work on equipment for extended periods of time. Workers tend to defer work under high heat conditions until temperatures above ground or within vaults cool sufficiently to allow safe continuous access. This may however cause a delay in the response to incidents on the electrical system.

Heavy precipitation, freezing rain and snowfall may make it difficult for all employees to travel to and from work, while also making it dangerous for field workers to get to equipment. During severe events such as high winds, tornadoes and lightning, workers apply their judgement and generally delay accessing equipment until the severe weather event has passed. Interestingly, the severity scoring of high winds at 70 km/h were slightly higher than scores for higher wind speeds (90 km/h, 120 km/h or tornadoes). This is because unsafe work conditions are very clear under extreme high wind events. However, at lower wind speeds, work conditions may appear to be acceptable, and workers may decide that the threat is reasonable given the need to restore electrical service. However, sudden, abrupt wind gusts could momentarily jeopardize worker safety.

As Toronto Hydro has occupational health and safety policies and procedures in place, the consequence of severe weather on workers tends to be delaying access and work on equipment until weather conditions, road access improves, and worksites are declared to be safe.

5.3 High Risk Interactions

The highest risks found in this study are related to structural damage and failure of electrical systems and components. In general, station equipment and overhead feeder systems were the two main system infrastructure categories susceptible to climate interactions that yield high risk interactions.

High Temperature

Days with peak temperatures above 40°C and days where average ambient temperatures exceed 30°C on a 24h basis are the two significant climate parameters rated as high risk for transmission and municipal stations. Days with peak temperatures above 40°C are currently a very rare occurrence, but are expected to occur on an almost annual basis by the 2030's and on an annual basis by the 2050's. Similarly, high ambient temperatures exceeding 30°C on a 24h basis are currently a rare occurrence, but may occur on an annual basis by the 2050's. In both cases, high electrical demand, coupled with loss of cooling efficiency, will cause station power transformers to overheat. In the most severe of cases, demand cannot be maintained without damaging station power transformers, which have an average replacement cost of around $500 K[21]. A coping mechanism employed by electrical utilities is to shed electrical load (load shedding), which entails instituting temporary outages in various sectors of the city in order to reduce load demand. For buildings and residents dependent on air-conditioning for cooling purposes, this represents a significant public health risk at a time of extreme heat events.

This high risk is especially relevant for transmission and municipal stations with low excess capacity by the 2030's and 2050's. As such, during periods of high demand, these stations have less excess capacity with which to meet electrical demand.

Freezing Rain and Ice Storms

There are three significant thresholds to consider for freezing rain and ice storm effects on the electrical distribution system. First, preliminary forensic analyses of outages from freezing rain indicate that 15+ mm of freezing rain is a trigger for the breaking of tree branches and limbs. These pose a threat to overhead feeder systems, and these freezing rain amounts have resulted in widespread outages in Toronto in the past due to tree contacts. The next threshold is 25 mm of freezing rain, which is the CSA design requirement for overhead electrical systems. Theoretically, overhead feeder systems, as well as the overhead exit lines at stations are supposed to withstand 25 mm of freezing rain (12.5 mm of radial ice accretion). However, such quantities of freezing rain and ice accretion on overhead infrastructure bring them to their structural design limits, which are further exacerbated by breaking tree branches and wind. Finally at 60 mm of freezing rain, the weight of ice accretion on overhead lines and station exit lines exceeds their design limit, and will likely cause them to collapse.

It should be noted that the high risk ratings for 15 mm and 25 mm of freezing rain on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[22]. From an annual probability perspective, freezing rain events at 15mm and 25mm of freezing rain would actually result in medium risk ratings. As can be seen from Table 3-2 in Chapter 3, the current annual probability of occurrence of 15 mm of freezing rain is 0.11 days / year (1 in 9 year return period), and is projected to increase to 0.16 days / year (1 in 6 year return period) by the 2050's. The current annual probability of 25 mm of freezing rain is 0.06 days / year (1 in 17 year return period), and is projected to increase to 0.09 days per / year (1 in 11 year return period) by the 2050's.As the projected trend for 15 mm and 25 mm freezing rain events is increasing in the future, the interaction of these two climate parameters with overhead feeder systems and station exit lines are maintained as a high risk.

Similarly, it was found that 60 mm freezing rain events would actually fall into a medium risk category (study period probability of 4, annual probability of 1, severity score of 7). However, major ice storms are part of a pattern of risk that is similar to 25 mm freezing rain events. For this reason, it is maintained in the high risk category

High Winds

High winds and wind gusts at 90 km/h and 120 km/h were judged to be a high risk to overhead feeder systems. These wind speeds reach and exceed the design limits of conductor connections to support poles, and the poles

[21] Estimate provided through correspondence with Toronto Hydro staff.
[22] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

themselves. Further compounding impacts is the potential for flying debris, such as broken tree branches and limbs, to further bring down overhead feeder systems.

The threats from high winds and gusts above 120 km/h were judged to be high risk due to wind forces on station overhead exit lines (exceeding design standard for poles). Furthermore, there is the potential for flying debris to damage station equipment at outdoor stations.

As is the case for freezing rain, it should be noted that the high risk ratings wind over 120 km/h were on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[23]. However, from an annual probability perspective, events producing 120 km/h high winds would actual result in low and medium-low risk ratings for station and overhead feeder systems respectively. This is because the current annual probability of 120 km/h wind events is 0.05 days per year (1 in 20 year return period). This frequency is expected to increase during the study horizon, although the projected value is not known. These significant wind events are similar to the case of tornadoes, in that they are infrequent but can lead to significant damage to large areas of the distribution system if they occur (low probability, high severity events). As they are however expected to be more frequent than tornadoes, the 120 km/h wind – overhead systems interaction is maintained as high risk in this study.

Lightning

Lightning strikes on station equipment, notably power transformers, were rated as a high risk. Lightning arrestors at stations are designed to direct lightning surge currents to ground and protect electrical equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially causing an outage to an entire service area.

Human Resources

Heavy freezing rain events constitute a high risk for Toronto Hydro personnel. First, slippery surfaces make travel to and from work, and out to worksites dangerous for field crews. Second, field crews also have to contend with a layer of ice over electrical equipment, trees, and other overhead structures such as buildings. As such, the risk of injury to workers from freezing rain events remain even after the storm has passed due to the continuous ice loads on overhead power lines and trees, which may cause them to break without warning.

5.4 Special Cases – High Severity, Low Probability Events

Tornadoes

Tornadoes represent a high severity, low probability event. As mentioned in Chapter 3, while the likelihood of a tornado event touching down at a specific point or location is extremely small, the likelihood of a tornado occurring somewhere in the City of Toronto over study period (2015 – 2050) is in fact considerable. Furthermore, due to the lake breeze effect, northern portions of the city tend to have a high probability of seeing a tornado event, although it does not preclude an occurrence closer to the lakeshore. Tornadoes were judged to have catastrophic consequences on all above ground infrastructure, while underground infrastructure may become inaccessible due to windblown debris.

[23] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

5.6 Special Cases – Low Severity, High Probability Events

Snowfall and freezing rain

The degradation of concrete and corrosion of steel materials (at grade and underground feeder systems) is a case of high probability, low severity events. These processes are accelerated by the application of de-icing salts during snowfall and freezing rain events. The application of salts can accelerate the corrosion of metal housing and enclosures of electrical equipment, resulting in shorter lifespans. It also affects the steel and concrete of vaults and cable chambers (civil equipment). Future warming associated with climate change is expected to decrease the number of days without snowfall, but the trend for freezing rain is expected to increase. Nonetheless, snowfall is expected to continue to be an annual event throughout the time horizon of this study. As such, degradation of civil structures will continue to be an issue for Toronto Hydro over the study period.

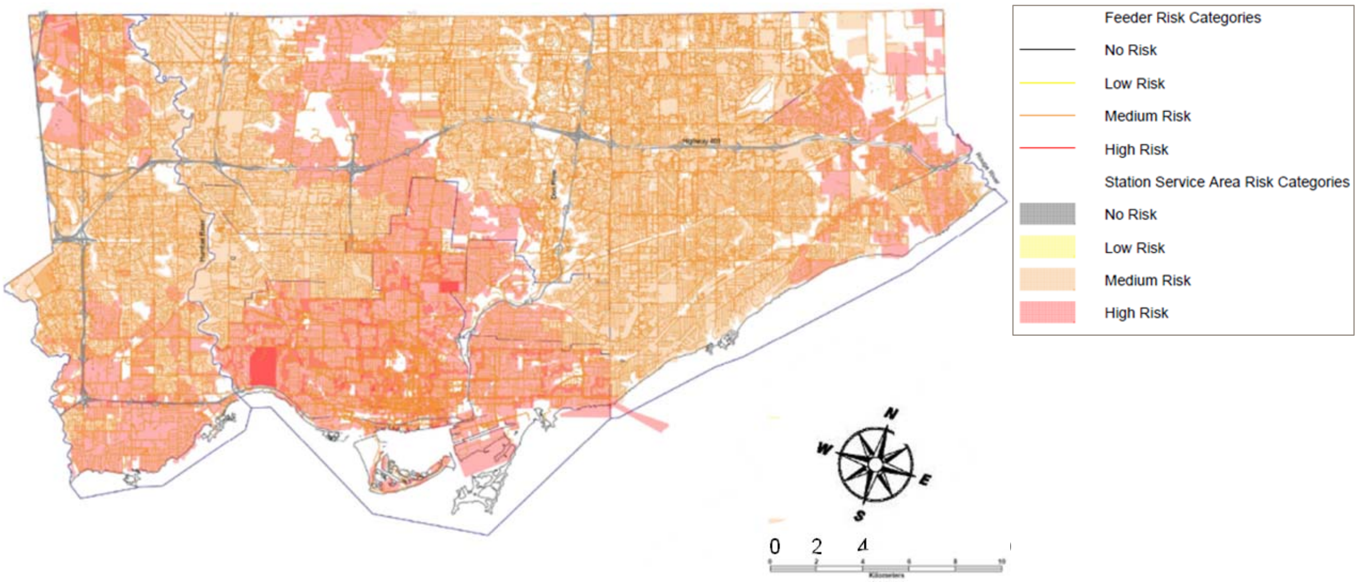
Underground electrical feeder equipment and civil structures located in the Former Toronto area received a slightly (+1) higher severity rating (and a medium-low risk rating) because the infrastructure is generally older than those found in the horseshoe area. It was found that older equipment and structures are more susceptible to degradation if corrosion had already begun (e.g. protective layers of paint may be worn off). Furthermore, older equipment may not be as resistant to corrosion as newer equipment due to the advancement of enclosure design and testing over time (Nema standard).

Some of this salt is dispersed by the moisture in the air, and can accumulate through the winter season on insulators on poles. These salt accumulations can cause electrical short circuits that could result in pole fires. Loop feeder systems are judged to be of lower risk than radial systems in the event of a short circuit or fire due to the potential to provide power temporarily through another loop of the feeder.

5.7 Mapping Risk Results

The mapping of risks provides complementary information to the risk assessment matrix, and facilitates a spatial understanding of low, medium and high risk interactions, and vulnerabilities (i.e. the medium and high risk interactions). For example, maps can provide an indication of the areas of vulnerability of overhead and underground infrastructure with respect to different kinds of weather events. Furthermore, the mapping exercise actually provides a new set of information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets (e.g. 120km/h wind and underground feeder assets), while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city (i.e. freezing rain affecting both station and overhead feeder assets). The following section provides some spatial observations about the four climate parameters affecting electrical distribution infrastructure. All mapping results are provided in **Appendix E**.

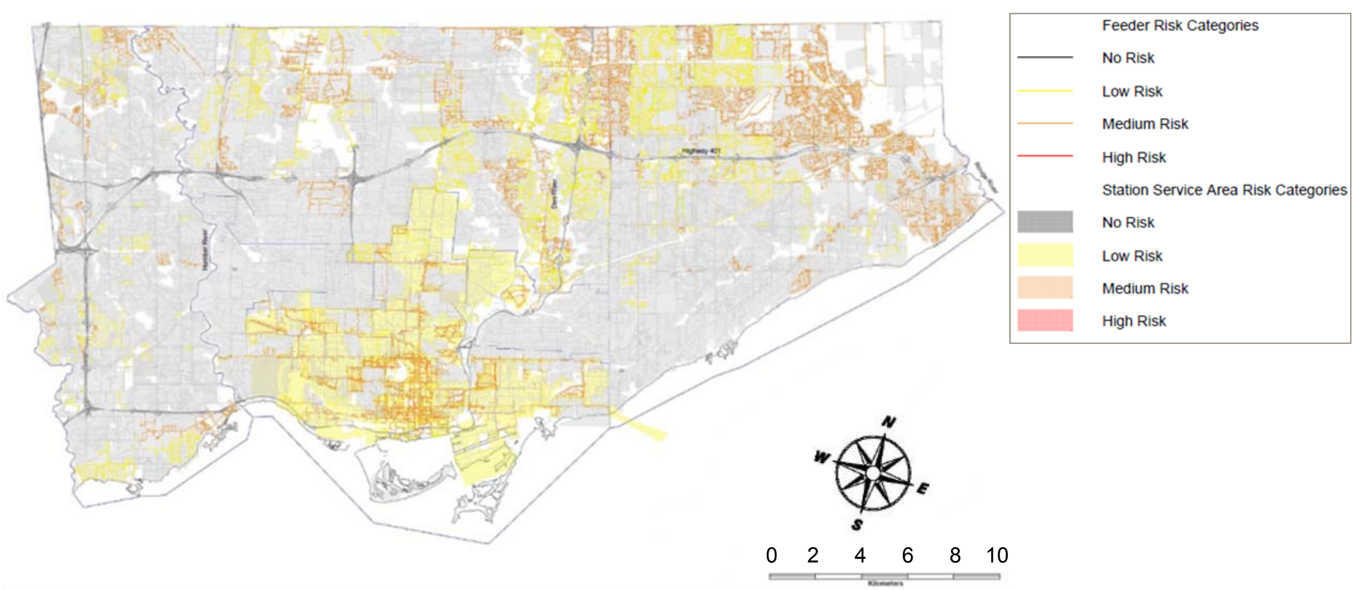
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's



Vulnerabilities from high heat events stem primarily from projected available station capacity by the 2050s, as this study did not find that vulnerabilities varied significantly (all rated medium risk) for feeder assets. Vulnerabilities to high heat events are more heavily concentrated in the Former Toronto area, although several horseshoe area stations would also be vulnerable during high heat events (Figure 5-1).

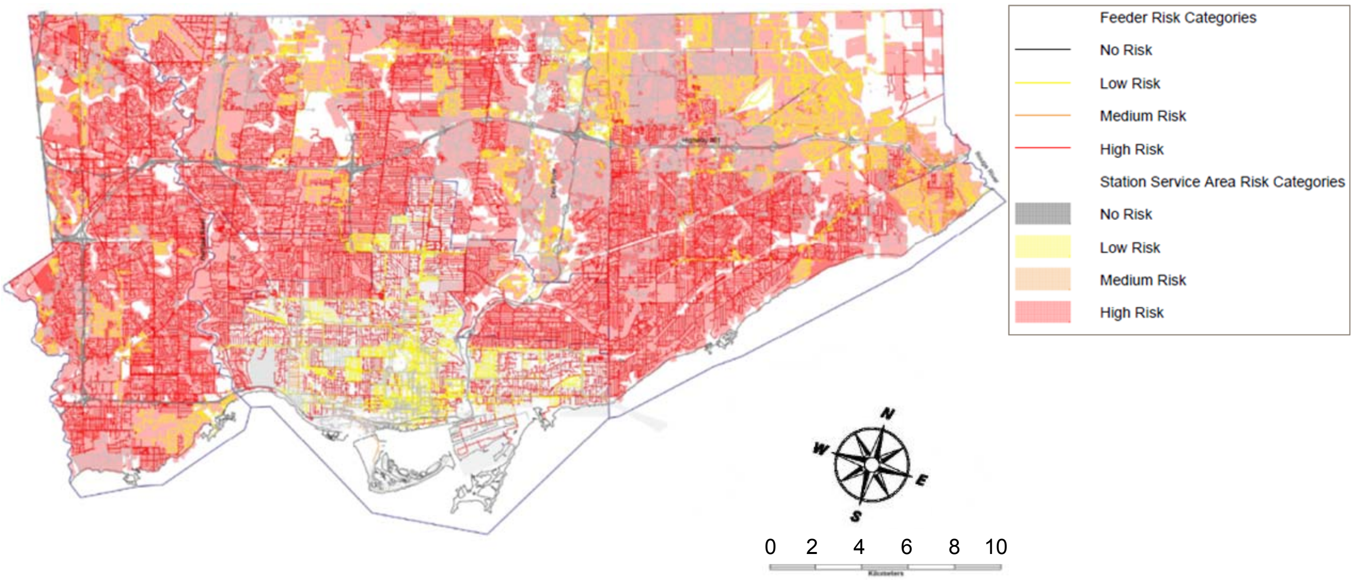
In terms of potential heavy rainfall risks to Toronto Hydro infrastructure, underground feeder systems that may be subject to flooding are located largely in the Former Toronto area and northeastern sections of the horseshoe (Figure 5-2). Some transmission station service areas in the Former Toronto area are marked as low risk due to the presence of some switchgear equipment that will likely remain in basements through the study period. Note however that sump pumps in stations make the probability of flood damage in stations from heavy precipitation less likely.

Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's



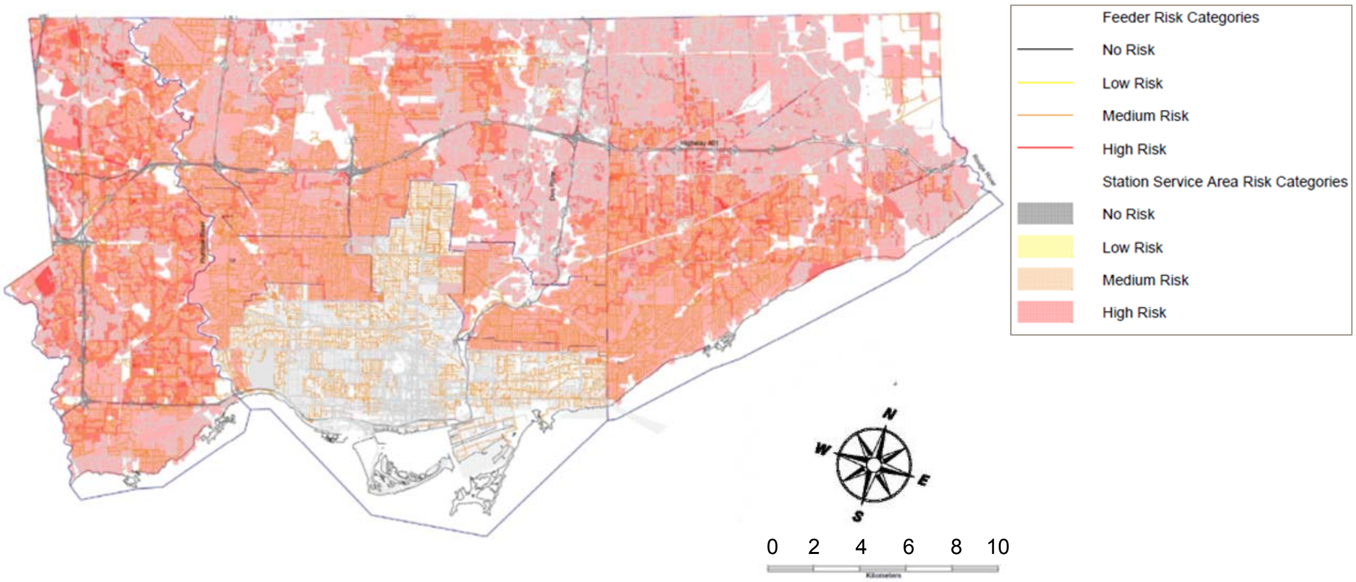
Toronto Hydro has a significant quantity of overhead distribution systems which are at vulnerable to extreme freezing rain, ice storms, high wind and tornado events. These feeder vulnerabilities combine with the fact that stations in the horseshoe area have station exit lines that are outdoors. This combination makes certain portions of the horseshoe particularly vulnerable to heavy freezing rain events and ice storm. Figure 5-3 shows the areas of vulnerability stemming from 25 mm of freezing rain, and is indicative of extreme precipitation/wind related vulnerabilities to overhead systems across Toronto.

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's



Lightning strike vulnerabilities are largely concentrated in the horseshoe area, where both outdoor station equipment and overhead feeder systems are predominant. However, overhead feeder systems in the the Former Toronto area are also vulnerable (Figure 5-4).

Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes



There are several caveats that should be mentioned with respect to interpreting mapping results, due in large part to the fact that risk ratings were evaluated based on general system characteristics. Localized site characteristics that may mitigate or worsen risk ratings were not adequately captured in the mapping exercise. They include:

- Local geographic characteristics, assets and features. There may be local site characteristics such the tree canopy cover, types of trees, presence of buildings or other overhead structures, which may exacerbate weather events (e.g. wind) or shelter infrastructure from impacts. The presence of low lying areas (e.g. bowls, flood plains) was also not considered. This level of detail, provided by a full site inspection and digital terrain mapping, were not available for this project. Such information would be useful in refining the risk ratings and mapping for extreme rainfall, freezing rain and wind;

- Areas with lower drainage capacity due to configuration of city storm drainage infrastructure. This type of information requires a very detailed understanding of city infrastructure, which was not available for this study. Furthermore, this level of data is most useful when combined with digital terrain mapping in order to identify low lying areas with problematic drainage. Finally, future projections as to how city infrastructure might evolve over time were also not available for this project;

- The moderating effect of Lake Ontario. As noted in Chapter 3, the lake can play a significant role in influencing temperature and humidity along the lakeshore. For example, the lake effect can moderate temperatures during heat waves and can reduce the possibilities of freezing rain or snow falling on areas closer to the lakeshore. The extent and intensity of the lake effect can vary depending on the event and weather conditions. It was not possible to estimate the geographic extent of the lake effect, or by how much the probability scoring for certain climate parameters may be affected. As such, the lake effect's moderating influence was not taken into account sufficiently in the risk assessment and mapping exercise;

- Local electrical configurations and characteristics. There are likely cases where location specific electrical equipment may make certain feeder or station systems inherently more robust or redundant than would be the case of the general class of equipment. For example, additional feeder ties, loops or circuits could make certain feeders more redundant in the event of a downed power line. The age of equipment, their future replacement schedule will also have an effect on their risk rating. This level of detail is not captured at level of analysis undertaken in this study;

- For the extreme rainfall risk map, it should be noted that the mapping of transmission stations includes all stations. Information identifying the location of the stations whose batteries and switchgear are located below grade was not available. Further analysis is required to identify the precise locations of transmission with below grade assets in order to get a better mapping of flood related risks.

In spite of these shortcomings, the mapping exercise represents a useful first approximation of spatial nature of electrical system vulnerabilities to climate change. Furthermore, this mapping information can be more easily combined with other layers of information such as technical hazard information (e.g. flood mapping), physical locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to produce further mapping studies and in depth analyses to suit the needs of other policy makers.

6 Engineering Analysis

This chapter presents the results of the Step 4 of the Protocol, the Engineering Analysis. The purpose of Engineering Analysis is to conduct a further assessment of the system-climate interactions that were rated as a medium risk (interactions scoring between 14 and 35). For these interactions, the engineering analysis attempts to evaluate whether the infrastructure is vulnerable to a changing climate. To do so, the various factors that affect the load and the capacity of the infrastructure for the study time horizon are calculated. However, quantitative calculations of load and capacity were not always possible to make due to a lack of data to support such an analysis. For this reason, professional judgment is also applied in the engineering analysis. Infrastructure which is found to be vulnerable is passed to Step 5, while those which were not were discarded from further consideration.

In total, nineteen medium risk interactions were analyzed. Fifteen of them were deemed vulnerable and passed to Step 5, while 4 were discarded from further analysis. The following table summarizes the results of the engineering analysis. A brief description of the reasoning behind the results for each of the medium risk interactions is presented in this chapter, while the full engineering analysis can be found in **Appendix G.**

Table 6-1 Engineering Analysis Results

	Affected infrastructure	Climate Parameter	Further Action Recommended
	Municipal and Transmission Stations and Communications Systems		
1.	Transmission and municipal stations	High temperature above 25°C and above 30°C	Yes
	Protection and control systems	All temperatures	
2.	Transmission stations	High temperature above 35°C	Yes
3.	Transmission stations	High temperature above 40°C and average temperature > 30°C	Yes
4.	Transmission stations	Heat wave and high nighttime temperatures	Yes
5.	Transmission and municipal stations	Freezing rain, ice Storm 60 mm	Yes
6.	Municipal stations	High temperature	Yes
	Underground and Overhead Feeders		
7.	Underground feeders	High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime	Yes
8.	Underground feeders	Extreme rainfall	a. Feeders/water treeing: Yes b. Nun submersible vault: Yes c. Above ground stations: No d. N/W feeders: Yes
9.	Padmount stations	High winds 120 km/h	No
10.	Overhead feeders (radial and loop)	High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave	Yes
11.	Overhead feeders (radial)	High nighttime temperatures	No
12.	Overhead feeders (loop)	Freezing rain, ice Storm 15 mm	Yes
13.	Overhead feeders (radial and loop)	Freezing rain, ice Storm 60 mm	Yes
14.	Overhead feeders (radial and open loop) and SCADA system	Lightning	Yes
15.	Overhead feeders (radial)	Snow > 5 cm and snow > 10 cm	No
	Civil Structures		
16.	Civil structures: underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events)	Yes
17.	Civil Structures: underground feeders (Former Toronto)	Snow > 5 cm and snow > 10 cm	No, but combinations of climates need additional study.
18.	Civil structures	Frost	Yes
19.	Human resources	All climate parameters	Yes

6.1 Municipal and Transmission Stations and Communications Systems

1. High temperature above 25°C and above 30°C / transmission and municipal stations and all Temperatures / protection and control systems

Further action recommended. Under higher temperatures, battery life expectancy (e.g. around 10 years) may decrease. Toronto Hydro has already encountered problems with some batteries failing prior to their expected lifespan..

2. High temperature above 35°C / transmission stations

Further action recommended, conclusions for high temperature and power transformers also apply (see Chapter 7). Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C also apply to this interaction.

3. High temperature above 40°C and average temperature > 30°C / transmission stations

Further action recommended. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and high nighttime temperatures (+23°C) / transmission stations

Further action recommended. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature > 30°C are also relevant to the heat wave and high nighttime temperature parameters.

5. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / transmission stations and municipal stations

Further action recommended. This interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events. Therefore, solutions for 25 mm events are also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / municipal stations

Further action recommended. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and cables.

6.2 Underground and Overhead Feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / underground feeders

Further action recommended. Toronto Hydro replaces cables based on asset life replacement cycles or premature failures. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / underground feeders

a. <u>Feeders: Water treeing of the cables, flooding</u>

Further action recommended. Climate change related stresses (i.e. higher temperature, higher loading, flooding from extreme rainfall) will continue to stress underground cables and constitute a vulnerability for Toronto Hydro.

b. <u>Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (Former Toronto has a high risk result)</u>

Further action recommended. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period.

c. <u>Above ground vault stations, access to the vault station and to the station equipment could be limited due to localized flooding of streets around the vault station, or at the station itself</u>

No further action required. This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. <u>Network feeders: old N/W protectors are not submersible</u>

Further action recommended. The old N/W protector may not operate properly if flooded. However, failure of the N/W protector will not automatically result in an interruption to the customer, since network systems are highly redundant. Toronto Hydro is installing new N/W protectors that are submersible, but there may still be older non-submersible N/W protectors in the systems, particularly in downtown over the study period. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and consequence of old N/W protectors being flooded.

9. High winds (120 km/h) / padmount stations on distribution network (Former Toronto)

No further action required. The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

Further action recommended. Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zones) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

No further action required. Night time temperatures with minimum ≥ 23°C in and of itself is not a significant concern for Toronto Hydro in terms of electrical service provision as peak demand has subsided. However, it is important to note that high daily temperatures in combination with high night time temperatures are a concern. This has been considered under different climate-infrastructure interaction, average temperature over 30°C on a 24 h basis, so this particular interaction does not warrant further action.

12. Freezing rain - ice Storm 15 mm and high winds 70 km/h / Overhead feeders in loop configuration

Further action recommended. The risk assessment of radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, the frequency of freezing rain events are projected to increase slightly by the end of the study horizon compared to present day (see table 3-2). The tree canopy may also be weakened by increased disease threats. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / overhead lines (radial and loop)

Further action recommended. See explanation for freezing rain and stations (item 5 above).

14. Lightning / overhead power lines (radial and open loop) and SCADA system

Further action recommended. It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, lightning strike intensity, the number of lightning arrestors/km and arrestor performance are not monitored by Toronto Hydro. Given this uncertainty, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability.

15. Snow > 5 cm and snow > 10 cm / overhead power lines (radial)

No further action required. The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue.

6.3 Civil Structures

16. Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events) / civil structures: underground feeders (Former Toronto)

Further action recommended. Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro, 2014a): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability

17. Snow > 5 cm and snow > 10 cm / civil structures: underground feeders (Former Toronto)

No further action required, but combinations of climates events require additional study. As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / civil structures (overhead and underground feeders)

Further action recommended. While the threat of frost is decreasing over the study period, it is noted that frost penetration will still occur with occasional extreme cold weather. Since Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts are judged to be a vulnerability.

6.4 Human Resources

19. All climate parameters / human Resources

Further action recommended. While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

7 Conclusions

The Phase 2 study presents a climate change based vulnerability assessment of electrical distribution infrastructure. It seeks to inform future investigations, planning and investment decisions on system and component vulnerabilities, and to support efforts to enhance the resilience of the electrical system. This chapter presents Step 5 of the Protocol and covers electrical distribution system vulnerabilities within the City of Toronto, adaptation options and areas of further study.

7.1 Vulnerabilities to a Changing Climate

The Phase 2 employed a high level risk based screening methodology to determine where infrastructure vulnerabilities to climate change may be present. All high risk infrastructure-climate parameter interactions, as well as medium risk interactions assessed as vulnerable through the engineering analysis comprise the vulnerabilities identified for Toronto Hydro's electrical distribution system to a changing climate. These vulnerabilities can be divided into five groups based on how climate parameters affect the system. The following paragraphs summarize these vulnerabilities, while table 7-1 provides more detailed information by infrastructure-climate parameter interactions.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting equipment cooling and electrical transmission efficiency. Two specific climate parameters were of most significant concern, daily peak temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. In these cases, the climate analysis found that such extreme temperatures have occurred only rarely in the past, but are projected to occur on an almost semi-annual to annual basis by the 2030's and 2050's respectively. Through preliminary demand and supply growth projections completed for this study, these vulnerabilities were identified based on the notion that extreme heat will generate electrical demand for cooling in areas where station excess capacity is projected to be marginal. Furthermore, such temperature extremes may cause equipment, notably power transformers, to operate beyond their design specifications and increases the likelihood of failure. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events cause immediate structural issues for overhead distribution assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, weight of ice) or by other objects (e.g. tree branches, flying debris). These kinds of events affect outdoor station and feeder assets, which are largely concentrated in the horseshoe service area. It is important to emphasize that Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual or even decadal frequency. More severe ice storms (60 mm), high winds (over 120 km/h) and tornadoes (EF1+) have been extremely rare in the past, and while there is a lack of scientific consensus on projected future frequencies for these extreme events, they are likely to remain rare in the future. Nevertheless, the damages caused by these kinds of events can be severe. Therefore, they were judged as ongoing and future vulnerabilities for Toronto Hydro.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets, which are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro and current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate the problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, the application of de-icing salts will also be applied annually through the study horizon. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's ITIS outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning activity will continue to be an area of vulnerability.

7.2 Adaptation Options

Adaptation options are suggested for all the infrastructure-climate parameter interactions identified as vulnerabilities. The Protocol classifies adaptation options in four possible categories:

- remedial engineering actions which aim to strengthen or upgrade the infrastructure;
- management actions to account for changes in the infrastructure capacity;
- continued monitoring of performance of the infrastructure and impacts; and
- further study required to address gaps in data availability and data quality.

Adaptation options by infrastructure-climate parameter interaction are presented in Table 7-1.

Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Stations, Communications and Protection Systems			
1. Transmission stations, municipal stations, protection and control systems Critical component: batteries	High temperature above 25°C	Further study required	Toronto Hydro has experienced problems with station batteries failing short of expected lifespans (i.e. approximately 10 years). Operating batteries in rooms where the ambient temperatures increases above 25°C is a contributing factor to premature battery failure (Toronto Hydro, 2014c). As battery rooms are not temperature controlled, Toronto Hydro could monitor how ambient temperatures of rooms within stations housing batteries fluctuate during the warmer summer months and evaluate whether additional measures are needed (e.g. review of battery technical specifications, including aging factor) to reduce battery degradation.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
2. Transmission stations, municipal stations Critical component: power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Further study required	Given the increased frequency of high heat conditions in the future, coupled with continued demand growth, infrastructure owners (Toronto Hydro and Hydro One), could conduct a could conduct a further study evaluating the technical and financial feasibility of installing transformers with a higher capacity, or installing more transformers at stations (shared load) where space permits. Another possibility is to evaluate the technical and financial feasibility of increasing the design standard for current power transformer equipment, for example, by designing to a daily average ambient temperature higher than 30 °C (35 °C) and maximum temperature with a higher temperature than 40°C (45 °C). Finally, these measures should be complemented by continued demand side management /energy conservation programs.
3. Transmission stations: only outdoor stations 4. Municipal stations: Horseshoe area outdoor stations Critical component: Overhead exit lines (for freezing rain and high winds parameters)	Freezing rain/ice storm : 25 mm, 60 mm High winds : 120 km/h and tornadoes	Management actions and further study required .	Major freezing rain, ice storm, high wind and tornado events are not expected to be an annual occurrence in the future, but will still likely occur over the study period. Station exit lines, either overhead ones or where underground cables surface, are a particular point of vulnerability, as downed exit lines can sever power supply to the entire service area. Toronto Hydro could monitor the frequency of damage to station exit lines and poles across a range of potential weather threats (freezing rain, high winds) to evaluate whether this critical portion of the distribution network requires strengthening. Toronto Hydro could also consider a station by station study of surroundings to identify areas around stations susceptible to generating flying debris (e.g. trees, buildings). Emphasis should also be placed on optimizing the emergency response and restoration procedures to reduce system down time. Note that Toronto Hydro is already undertaking a review and enhancement where necessary of response planning, dispatching operations, prioritization of restoration activities, coordination with other utilities, response team training and preparation.
Arresters (for lightning parameter)	Lightning	Monitoring activities	Lightning events and strikes are difficult to predict, but are likely to increase in frequency and intensity. However, lightning strike intensity and arrester performance is not currently monitored. Given the importance of lightning strikes as a cause of outages, it is recommended that the lightning activities (e.g. frequency, intensity), soil resistivity (i.e. decreased soil moisture from longer and hotter summers) and impacts on the system could be more closely monitored to provide more information regarding the risks of lightning strikes. For example, where high voltage arresters are installed, counters (if not already present) could also be installed to check if a particular phase or transmission line suffers from an exceptionally high number of overvoltages leading to arrester operation. Lightning strikes on the building housing stations could be investigated to determine whether they resulted in any overvoltage impacts. If further studies on lightning activity result in a better definition of lightning characteristics and impacts, or if monitoring indicates a higher rate of failure, a review of actual design practices could be undertaken.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Feeders, Communication and Protection Systems			
5. Underground feeders Critical component: cables and power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Monitoring activities	For power transformers, see discussion above on station power transformers (see row 2). For cables, increased temperature operation tends to reduce the dielectric strength of the cables. Toronto Hydro is currently trialing cable diagnostic testing techniques as a method of detecting vulnerabilities in cables. If cable testing techniques prove reliable in detecting potential failures, Toronto Hydro could consider extending diagnostic techniques to all cables to monitor heat stress impacts on cables to evaluate whether high design standards or more frequent replacement is required.
6. Underground feeders : Submersible type Critical component: cables	Extreme rainfall: 100 mm <1 day + antecedent	Monitoring activities	The presence of water can lead to an electrical failure of the cables (water treeing) and/or reduce the dielectric strength of cables. Cable diagnostic testing can be employed to monitor the degradation of underground cables. This study also supports Toronto Hydro's program to replace and renew older cable assets with moisture and tree resistant underground conductors such as TRXLPE cables. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
7. Underground feeders: Vault type – Below ground Critical component: non-submersible equipment	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Toronto Hydro is currently upgrading non-submersible equipment located in below grade vaults with submersible equipment, or relocating them above grade. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
8. Underground feeders: 13.8 kV Network systems	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Many old network protectors are not submersible, particularly in the downtown area. The current Toronto Hydro standard is to use submersible network protectors when replacing old equipment. Further study could be undertaken to evaluate the benefit and cost of replacing old network protectors prior to their end of life versus replacement at their end of life (i.e. potential for flood damage and outages prior to replacement).
9. Overhead feeders (Radial and loop) Critical component: power transformers and conductors	High temperature above 35°C High temperature maximum above 40°C Average daily temperature > 30°C Heat wave	Monitoring activities	Climate change is projected to increase the frequency of high heat conditions in the future. Coupled with continued demand growth, this is projected to increase heat stresses on overhead distribution feeder assets. However, unlike the case with station transformers, where projected heat and capacity reveal a clear vulnerability in terms of supply capacity, it is not clear whether high temperatures will have the same impact across the distribution feeder system (i.e. are there bottlenecks to supplying electricity during periods of high heat at certain stations or across the grid?). Toronto Hydro should continue to monitor key grid operational indicators for distribution transformers, such as load currents, billing data, transformer oil and ambient temperatures. This information can be used to help evaluate whether distribution line capacities are sufficient to handle increased electrical loads.
10. Overhead feeders (Radial and loop) Critical component: conductors	Freezing Rain/Ice storm: 15 mm and high winds 70 km/h	Management actions and remedial engineering actions	Toronto Hydro is already experiencing outages caused by tree contacts and is planning to increase its vegetation management activities. This study supports the need for increased tree trimming practices around overhead power lines and use of tree proof conductors in areas where outages due to tree contacts have been frequent.
11. Overhead : Radial and Loop Critical component: poles	Freezing rain/ice storm: 25 mm High winds: 90 km/h and 120 km/h, tornadoes	Management actions and further study required	See recommendations for stations above on freezing rain and tornadoes (see row 3).

Affected infrastructure	Climate Parameter	Adaptation Option	Details
12. Overhead power lines (radial and open loop) and SCADA system	Lightning	Monitoring activities	See recommendations for stations above on lighting (see row 3).
Civil structures			
13. Civil structures: Underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 60 mm (combination of events)	Further study required	While maintenance can mitigate the risks of civil structures deterioration, changing climate conditions (e.g. freezing rain, rainfall, freeze-thaw) may exacerbate premature degradation issues. However, it could not be determined in this study whether current design standards are sufficient to withstand future climate - salt and moisture related degradation. Further study could be undertaken to estimate salt/moisture corrosion effects in relation to climate change.
14. Civil structures: transmission and municipal stations, underground feeders	Frost	Further study required	The nature of the frost heave impacts to civil structures was not sufficiently evaluated within this study. Further study can be undertaken to identify whether there are any specific location, ground condition and structure combinations which contribute to frost heave impacts.
Human Resources			
15. Human Resources	Heat, freezing rain, wind and tornadoes	Management actions	Toronto Hydro applies an occupational health and safety manual. Toronto Hydro is already conducting a review of its procedures in light of future extreme events to determine whether modifications in procedure or training are needed.

7.3 Other Areas of Study

Additional climate and infrastructure related areas of further study that can be used to enhance the understanding of electrical system vulnerabilities to climate change are listed below.

Climate

- Increase monitoring of important climate parameters across the city. For both the climate assessments and forensic analyses, a lack of observational data made understanding climate risk challenging and introduced uncertainties, particularly for specific climate parameters such as wind gusts, hourly rainfall measurements, and freezing precipitation accumulations. New monitoring would provide important benefits, including:
    - Addressing gaps in historical data;
    - Facilitating comparisons between sites across the city;
    - Improving the spatial resolution of the climate monitoring network, increasing the likelihood of capturing important meteorological events; and,
    - Providing additional data to assist in detecting new and emerging trends sooner than would be possible using the current network.
- Enhance details about weather impacts contained in the ITIS database. Although information contained within the database was extremely useful and yielded important insights, there were still gaps in the details of weather related outages which limited the evaluation of impacts;
- Refine and expand forensic investigations (see **Appendix C**) completed in this Phase 2 study. Several climate parameters, individual climate events and impacts were not investigated thoroughly due to the scope of the present study. In particular, further analyses could be done on:
    - Lake modified air and lake breeze influences on atmospheric hazards, especially extreme temperatures, ice accretion events, and severe thunderstorms (including extreme rainfall, downbursts/microbursts, and tornadoes);
    - December 2013 ice storm and other ice accretion events, particularly to help refine understanding of apparent variations in impacts between different sections of the city.

    - Temperature gradients across the city during periods of extreme heat. For example, why do some days show greater temperature gradients across the city than others, and what impact does this have on the system?
- Monitor and study the complex interaction between changes in tree growth, pest and disease conditions and resultant changes in risk to overhead systems. This could include investigating
    - The extent to which accelerated tree growth affects tree strength, and specifically resistance to wind and ice accretion loading;
    - Emerging and/or worsening tree pest and disease conditions which could reasonably be expected within the City of Toronto in the coming decades, and what potential changes in risk these will pose to overhead systems.

Infrastructure

- Site specific electrical configuration and area characteristics were not collected due to the scope of this study and scale of infrastructure system being analyzed (e.g. land use changes, high rise and condo development, population growth, terrain elevation, sewers, storm sewers, roads, tree canopy and tree type, buildings). Specific site characteristics, equipment age, or unique or uncommon equipment can alter sensitivity and vulnerabilities. Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and identify more site specific vulnerabilities;
- The scope of study and level of effort did not permit a detailed analysis of system performance and outage management (i.e. simulations of power rerouting or contingencies under different outage scenarios to various parts of the system). Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and permit a more detailed study and understanding of system performance and outage management;
- Smart Grid Data: Toronto Hydro has recently begun collecting information about outages from its grid based on smart grid feedback. Data history was short and not reviewed in this analysis. Further study examining smart grid data can be used to identify problem areas due to high load demand.

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Appendix A
Workshop Presentations

Appendix B
Background Information on Developing Climate Data

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Appendix D
Risk Assessment Matrix

Appendix E
Risk Maps

Appendix F
Load Projection Methodology – Toronto Hydro

Appendix G
Engineering Analysis

Appendix H
PIEVC Worksheets

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report Appendices - Public

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Appendix A
Workshop Presentations

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Appendix B
Background Information on Developing Climate Data

Appendix B: Background Information for Developing Climate Data

B.1 Introduction

The following Appendix provides additional details about the methods used to develop the climate data used in the Toronto Hydro PIEVC Climate Change Risk Assessment. The development of climate data to support this study involved three main activities.

- Identify climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate; and,
- Convert projected probability of occurrence of future climate parameters into the seven point scoring scale employed by PIEVC studies to support the risk assessment.

This appendix provides more detailed information about the first two activities, namely the identification of relevant climate hazards and the estimation of their probability of occurrence in the future. The conversion of this probability information into PIEVC scores is not covered here, as it is already explained in the PIEVC Protocol V. 10.

B.2 Identification of Climate Parameters and Infrastructure Thresholds

In this study, the identification of relevant climate parameters and infrastructure impact thresholds (i.e. climate hazards) involved a combination of the three methods:

- Literature review;
- Practitioner consultation; and,
- Forensic analyses.

B.2.1 Literature Review

Design values in codes and standards generally provide an excellent "first guess" to determine infrastructure impact thresholds, providing information on not only baseline climatic design values, but on safety factors, load combinations, and so on. Codes and standards can also provide an understanding of changing thresholds depending on the age of infrastructure and therefore applicable code or standard. These values can also be used as a basis for discussion with practitioners, to determine if there are local modifications for in-field infrastructure. The occasional review and updating of codes and standards also tends to generate discussion and papers in the published literature, which can further provide background on why changes were made, how climatic data was processed, and when these changes became effective.

B.2.2 Practitioner Consultation

Discussion and consultation with practitioners is invaluable. Practitioners can describe important historical events and their impacts, relevant logistical and operational elements of the system, and new and emerging problems which may not be documented elsewhere. More generally, practitioners can provide guidance on where problematic interactions tend to arise and what can be done to reduce those impacts (i.e. adaptation measures).

This project included two workshops in which assumptions regarding climate elements and infrastructure breakdown were evaluated, discussed and modified. The first workshop played a significant role in re-evaluating climate elements which had been identified under Phase I. For example, in light of recent severe weather events **(see Appendix C)**, extreme rainfall and freezing rain were given somewhat higher priority under Phase II. Following a preliminary climate analysis, several thresholds were removed, modified, or refined at the second workshop, and the discussion of complex interactions confirmed findings from the forensic.

B.2.3 Forensic Analyses

Forensic analysis is the evaluation of past events through the application of scientific techniques and understanding to establish facts. It is meant to diagnose the causes of, and contributing factors to, a given infrastructure failure incident. These analyses can be used to refine our understanding of not only what caused a given failure, but also how to prevent or reduce the risks of similar failures in the future. In the context of extreme weather, we can evaluate the meteorological conditions associated with an incident and compare those to impacts produced (i.e. what was damaged, how was it damaged, etc.) and the supposed design capacity of that system (i.e. what was it designed for, do field conditions match design requirements).

Forensic analysis first requires the identification of important historical climatic events. In this case this was provided by Toronto Hydro's ITIS database, and further augmented by newspaper and press release searches. These events were then compared to all available observational data, including both Environment Canada's climate network and as well as data provided by TRCA (TRCA 2014) for several specific events. A full report containing analyses of several different events in the GTA is provided in **Appendix C**. These results were then compared to the literature and were also presented to practitioners for further scrutiny. Findings included the apparent impact of tree canopies on wind resistance of trees (resulting in subsequent secondary impacts on overhead systems), as well as regional differences in impacts from freezing rain, likely the result of a combination of local meteorological conditions (temperature regimes) and regional differences in canopy cover and tree health.

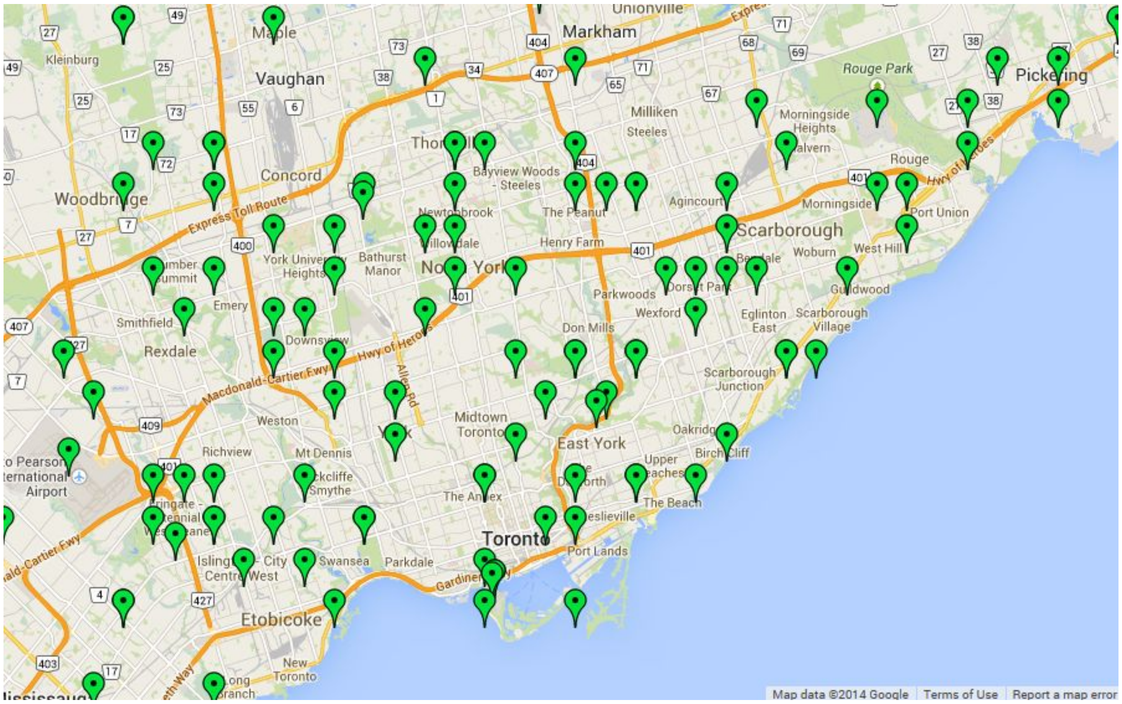
B.3 Establishing the Probability of Occurrence of Climate Hazards

The following section provides information necessary to project the future probability of occurrence of climate hazards. Information about the development of a historical climate baseline, the sourcing and use of future climate projection data, and the treatment of complex variables is presented.

B.3.1 Historical Climate Observations

Environment Canada is the authoritative source of climate information in Canada. In the Toronto region many observations stations have been in place and subsequently closed (see **Figure B.1**). In most cases stations only have observations for a few years – too short to establish a 'climatology'. The most recent normals period established by the World Meteorological Organization (WMO) was 1981-2010. Although 30 years is the accepted minimum, Environment Canada has calculated normals for stations which have at least 10 years of data within this period.

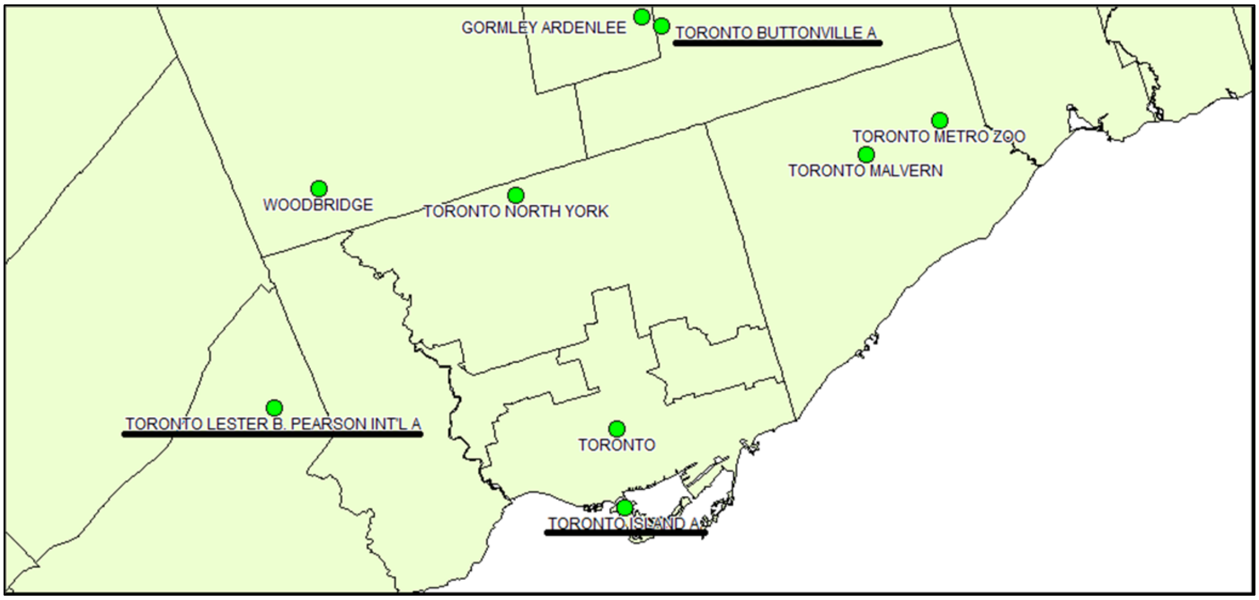
Figure B.1 All Historical Environment Canada Stations



Note: includes those not currently open

To establish reliable statistics on the frequency of events, long term records are preferred and with this area, there are some stations available. It is generally accepted that to establish a ‘normal’ climate, a minimum of 30 years of data as required. This supposedly ensures that short term natural variability is averaged out. Detailed hourly observations are usually only available at airport locations such as Toronto Pearson, Buttonville and Toronto Island. These airport locations are also typically the only source of variables other than temperature and precipitation (such as wind or weather observations). Of these, Toronto Pearson has the lengthiest reliable data record. Those regional stations for which normals data was calculated for 1981-2010 are shown in **Figure B.2**.

Figure B.2 Environment Canada 1981-2010 Normals Locations



Note: Stations with additional weather and wind data are underlined.

B.3.2 Future Projections

B.3.2.1 Global Climate Models

These variables will consider both the historical period frequencies observed in the region and the corresponding projections used in the most recent Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5). The suite of models used in AR5 is from the Fifth Coupled Model Intercomparison Project (CMIP5), coordinated by the World Climate Research Program, and was retrieved from the following data portal:

http://cmip-pcmdi.llnl.gov/cmip5/guide_to_cmip5.html.

Since the second IPCC Assessment released in 1995, the number of contributing international climate modelling centres, models, and their complexity, have increased significantly – from 11 models to the current 40. With increased computing power, better refinement of atmospheric phenomena have been incorporated, and model spatial and temporal resolution has improved (Kharin et al. 2013). An important outcome of this increase in model availability is the ability to produce projections of future climate based upon an 'ensemble' of many models versus the use of single or only a few models. In this report, all available AR5 model runs (many models have more than a single projection available) were used. The use of multiple models to generate a 'best estimate' of climate change is preferred over a single model outcome. Research has indicated that the use of multi-model ensembles is preferable to the selection of a single or few individual models since each model can contain inherent biases and weaknesses (IPCC-TGICA, 2007, Tebaldi and Knutti, 2007). The use of the ensemble projection from the family of global modelling centers is likely the most reliable estimate of climate change projections on a large scale (Gleckler et al, 2008).

A full list of the climate models and their country of origin is presented in **Table B.1**.

Table B.1 List of CMIP5 Global Climate Models (GCMs) Used for this Study

Model Name	Organization	Country	Organization Details
ACCESS1-0	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4	NCAR	US	National Center for Atmospheric Research
CESM1-BGC	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
HadCM3	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-AO	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere

Model Name	Organization	Country	Organization Details
			and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC4h	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MIROC5	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3	MRI	Japan	Meteorological Research Institute
NorESM1-M	NCC	Norway	Norwegian Climate Centre
NorESM1-ME	NCC	Norway	Norwegian Climate Centre

B.3.2.2 Representative Concentration Pathways

A new initiative in the IPCC AR5 is the introduction of RCPs (Representative Concentration Pathways; see **Figures B.3** and **B.4**). They represent a range of possible projection outcomes which depend upon different degrees of atmospheric warming. The lowest RCP 2.6, represents an increase of 2.6 W/m^2 to the system, while the highest RCP 8.5 represents an increase of 8.5 W/m^2 of energy. This range encompasses the best estimate of what is possible under a small perturbation situation (2.6) and under a large increase in warming (8.5). It is unknown which of the RCPs will apply in the future. However, it is important to note that historically, the GHG emissions have followed the highest (8.5) pathway. In the absence of a global agreement on GHG reduction, this trend is expected to continue which would support this pathway going forward. Nevertheless, in this report, 4.5 (moderate) and 8.5 (high) projected change are presented. The number of models used for the ensemble varies with the RCP selected since not all international modelling centres generated model runs for all RCPs.

Figure B.3 Representative Concentration Pathways used for AR5

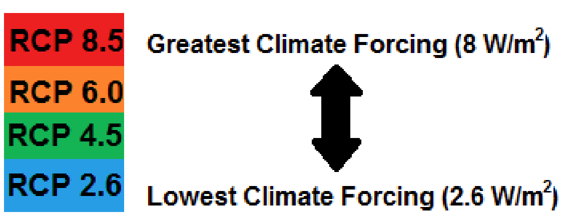
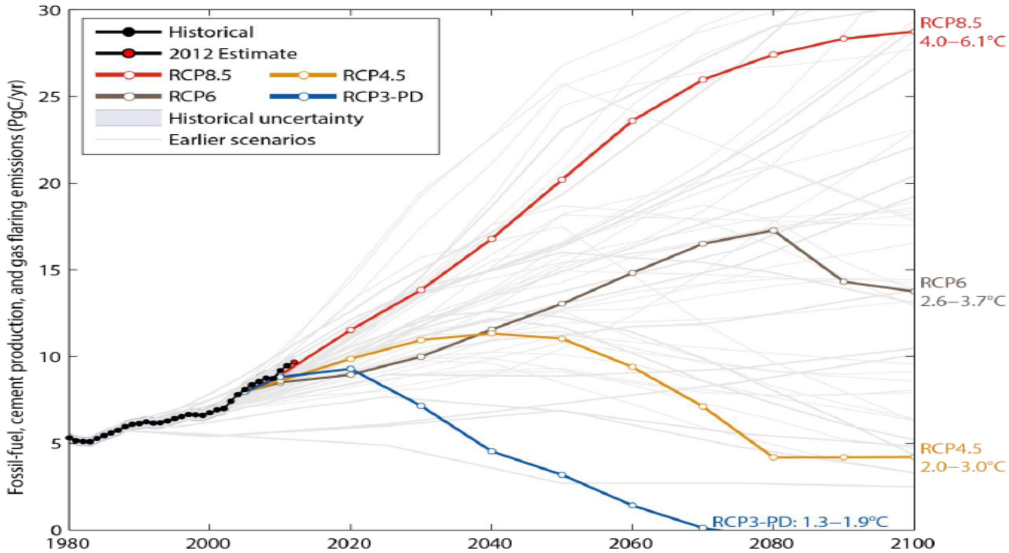


Figure B.4 Global GHG Emissions and their Relationship with Representative Concentration Pathway Assumptions



Source: Peters et al. 2012a

Factors influencing the RCP include population growth, economic growth, degree of urbanization, land use change, use of green versus carbon-based energy sources and any future international agreements on greenhouse gas (GHG) emissions, among others.

B.3.2.3 Important IPCC Findings

The full IPCC AR5 Working Group 1 Report was released in September 2013 and provides general details of the IPCC position on climate change. It can be found here: http://www.ipcc.ch/report/ar5/wg1/

Some of the main findings of this report are summarized in the Summary for Policymakers and are reproduced below:

- Warming of the climate system is **unequivocal**, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.

- Each of the last three decades has been successively warmer at the Earth’s surface than any preceding decade since 1850.

- Over the last two decades, the Greenland and Antarctic ice sheets have been losing mass, glaciers have continued to shrink almost worldwide, and Arctic sea ice and Northern Hemisphere spring snow cover have continued to decrease in extent.

- The atmospheric concentrations of carbon dioxide (CO2), methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years.

- Human influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system.

- Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. This evidence for human influence has grown since AR4. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.

- Observational and model studies of temperature change, climate feedbacks and changes in the Earth's energy budget together provide confidence in the magnitude of global warming in response to past and future forcing.

- Climate models have improved since the AR4. Models reproduce observed continental-scale surface temperature patterns and trends over many decades, including more rapid warming since the mid-20th century and cooling immediately following large volcanic eruptions.

- Global surface temperature change for the end of the 21st century is *likely* to exceed 1.5°C relative to 1850 to 1900 for all RCP scenarios except RCP2.6. It is *likely* to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform.

- Changes in the global water cycle in response to the warming over the 21st century will not be uniform. The contrast in precipitation between wet and dry regions and between wet and dry seasons will increase, although there may be regional exceptions.

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

With each subsequent report, the evidence of climate change builds and increasingly points towards greater confidence that human-kind is having and will continue to influence our future climate, from warming, to extreme events, to sea-level rise to melting sea-ice. Among the most recent IPCC reports was the addition of a separate document on climate extremes, the IPCC SREX document (SREX-IPCC, 2012). So in addition to changes in the mean climate, extreme climate events will also be impacted, and in many cases the changes in the extremes are expected to be greater than mean changes.

Of particular interest are some conclusions from the extremes report (SREX-IPCC, 2012):

- It is *virtually certain* that increases in the frequency and magnitude of warm daily temperature extremes and decreases in cold extremes will occur in the 21st century at the global scale.

- It is *very likely* that the length, frequency, and/or intensity of warm spells or heat waves will increase over most land areas

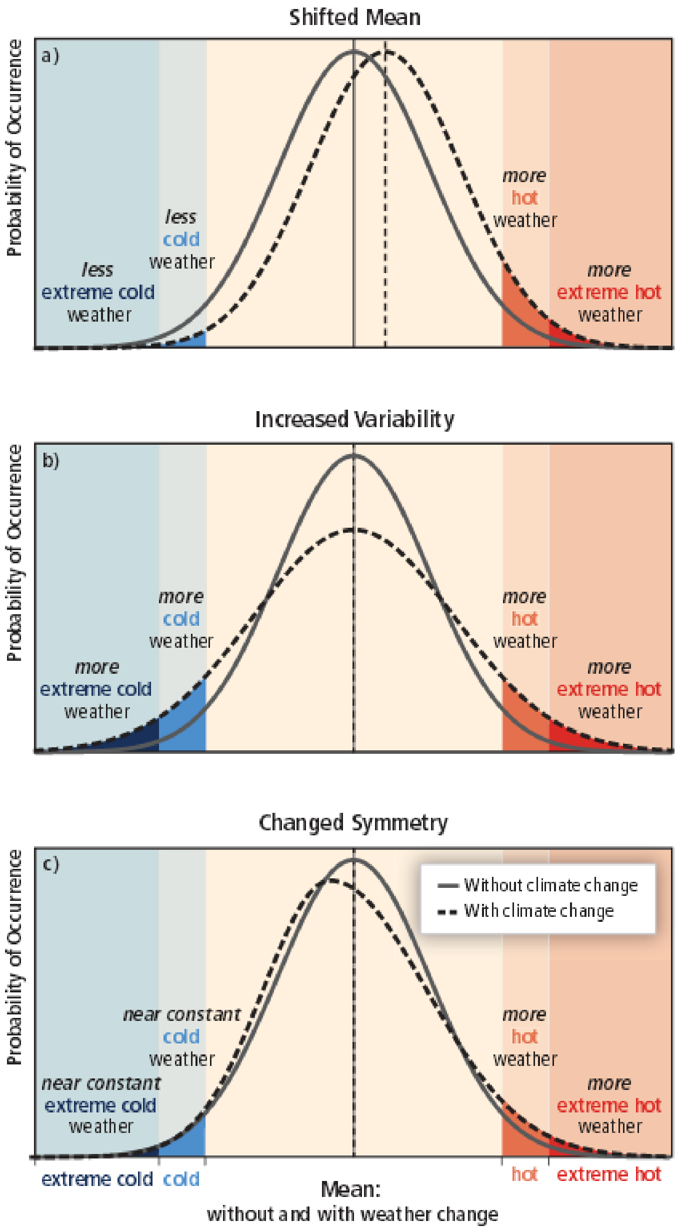
- It is likely that the frequency of heavy precipitation or the proportion of total rainfall from heavy falls will increase in the 21st century over many areas of the globe

- Extreme events will have greater impacts on sectors with closer links to climate, such as water, agriculture and food security, forestry, health, and tourism

- Attribution of single extreme events to anthropogenic climate change is challenging

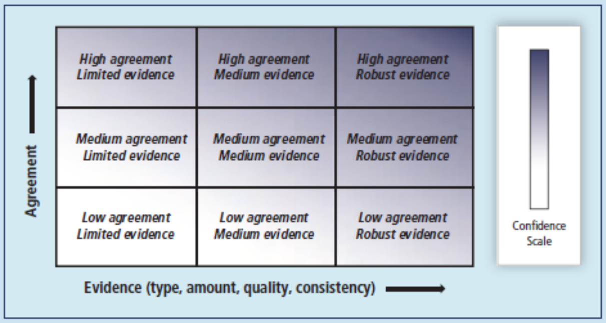
An example from the report is shown below for changes in temperature, which demonstrate how greater likelihood of extremes is possible through changes in mean, variability and symmetry.

Figure B.5 How Changes in Temperature Distributions can affect Extremes (IPCC, 2012)



Confidence wording in the IPCC documents are characterized by the use of specific terms such as 'very likely' or 'virtually certain', where in previous reports changes may have been referred to as 'likely'. There has been a gradual increase in confidence of the projections from climate models over time. A summary of the confidence terminology used in the official reports is shown below (SREX-IPCC, 2012):

Figure B.6 IPCC Confidence Terminology



A depiction of evidence and agreement statements and their relationship to confidence. Confidence increases toward the top-right corner as suggested by the increasing strength of shading. Generally, evidence is most robust when there are multiple, consistent independent lines of high-quality evidence.

The following terms indicate the assessed likelihood:

Term*	Likelihood of the Outcome
Virtually certain	99–100% probability
Very likely	90–100% probability
Likely	66–100% probability
About as likely as not	33–66% probability
Unlikely	0–33% probability
Very unlikely	0–10% probability
Exceptionally unlikely	0–1% probability

* Additional terms that were used in limited circumstances in the Fourth Assessment Report (*extremely likely:* 95–100% probability, *more likely than not:* >50–100% probability, and *extremely unlikely:* 0–5% probability) may also be used when appropriate.

With each report there are more and higher quality observations of the changing climate and improvements in the models equations/parameterizations, and their spatial and temporal detail. The IPCC reports continue to provide the best science-based information on projected climate change assembled from the best climate researchers worldwide. Climate change projections for this report are based upon the same new models used for guidance in the IPCC AR5 report recently released.

B.3.3 Climate Projection Methodology

B.3.3.1 The Delta-Method Applied to the Ensemble

The use of the CMIP5 ensemble not only allows for the calculation of an average projection of future climate which represents the consensus of all independent models, but it also allows for the estimation of projection uncertainty and statistical distributions which could not be determined from a single model. The projections for the variables in this report represent the 'best estimate' available – and are more indicative of the general expectations of climate change over any single model.

The ability of the CMIP5 ensemble to reproduce the historical temperature gives us confidence that the newest models used in this report are reliable and when grouped can provide accurate estimates. This would imply that reliable historical climatology should lead to reliable future projections.

This study uses a so-called 'delta' approach (sometimes also called 'climate change factor approach'), to obtain future estimates of climate variables. It is generally comprised of the following tasks.

1. Obtain a baseline climate condition (or 'average' climate).

2. Using an ensemble of all available CMIP5 models ('CMIP5 ensemble'), we obtain the model average climate for this same period – the average of all models for the grid covering Peel region. However, each modeling center does not use the same grid alignment and resolution, so a first step before obtaining the average of all the models is to regrid them all to a common resolution. This regridding typically uses a scale representative of the resolution of the models, in this case approximately 200 by 200 km.

3. The CMIP5 ensemble future climate is obtained for this same cell for each of the required future periods. In this case, every 10 years starting in the year 2011 and ending in the year 2100. From this we will have average future conditions of all the models for ten 10 year periods.

4. The difference (or 'delta') between the CMIP5 baseline and CMIP5 future periods are obtained – this represents the change in climate condition. Ten climate deltas are produced, for example, the delta between the baseline (1981-2010) and the 2051-2060 period is one of the deltas.

5. The final step is to then apply this delta value to the baseline period.

B.3.3.2 Complex Climate Events: Regional Climate Models and other projection techniques

The delta method applied to an ensemble of GCMs is not the only method available for climate change studies. Instead of using a delta ensemble approach, the delta approach could also be applied to single model, but the projection estimates would therefore only rely on ones assumption that the single model employed was the ideal choice. In climate science there are tradeoffs between model complexity and expediency.

It should be noted that many high impact atmospheric events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. lightning, freezing rain, ice storms, tornadoes). Two main strategies have been developed to help address this, the use of regional climate models (RCM's) [1] and statistical downscaling studies. Both strategies were used in Phase 2 for several of the more localized and shorter duration climate elements analyzed. For one set of climate hazards (e.g extreme temperatures), the technique of employing a climate analogue was also used to validate the "delta-method" for determining these climate hazard probabilities.

Regional Climate Models

Another approach for obtaining specific climate projection information is to run a very high resolution model once over the area of interest (so called 'dynamical downscaling'). In the simplest of terms one can either have 'many model runs at a coarse resolution' or 'few model runs at high resolution'. These high resolution models are called 'Regional Climate Models' (RCMs). There are RCMs available, but this data can be difficult to obtain and they still require a coarser resolution CMIP5 or earlier model to act as a precursor. Over North America, the North American Regional Climate Change Assessment Program (NARCCAP) has assembled less than a dozen RCMs for various time periods (http://www.narccap.ucar.edu/). As these models have a high temporal and spatial resolution (i.e. hours and tens of kilometers), there are fewer RCMs available than the CMIP5 Global Climate Model collection. In addition there are far fewer model runs from which to obtain an average climate change value. For this study, the decision was to use many coarser models from which to obtain the climate change signal rather than fewer higher resolution models. However, some of the probability results for one set of climate hazards in Phase 2 (extreme temperatures) were generated using the CANRCM4 model, and a discussion of associated uncertainties can be found under the specific descriptions for those climate hazards found below.

Statistical Downscaling

Statistical downscaling studies attempt to solve the spatial challenges by developing statistical links between GCM scale climate conditions and localized, short duration events (e.g. freezing rain/ice accretion and wind gusts). Historical, point location climate data is compared with conditions on the scale of GCM grids. Statistical links, so called "transfer functions", are then developed based on these relationships. After GCM projections are developed for a given future period, these transfer functions are then used to "downscale" GCM projection back down to local scales. Although much less computationally intensive than RCMs, individual statistical downscaling studies still require significant expertise and time for proper execution.

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[1] These are sometimes referred to as "dynamical downscaling" methods, to provide an analogous term to alternative "statistical downscaling" methods.

The main drawback of this technique is that climate projections can then only be obtained from specific observation station locations which have sufficiently long data records. This method calibrates historical climate observed at an observation station (for example Toronto Pearson Airport), with historical model data at a coarse scale (called 'predictors'), to obtain a statistical relationship. For example, perhaps the daily temperature observed is related to the modeled upper atmosphere wind direction. If one provides the future upper atmosphere wind direction from a climate change model, it could then be used as one of the variables to predict the future temperature. The difficulty with this process even with pre-constructed software is that spurious associations based on pure statistics and not climatology can be applied which would produce unrealistic future conditions. Certainly some expertise in the statistical software is required. Additionally, this method requires specially formatted input statistical climate model data which is only available for a few models – and for few model runs and RCPs. This procedure would have to be repeated for all station locations for which there was long term reliable station observation data to produce estimates of climate change for only those specific locations.

An IPCC document entitled "Guidelines for Use of Climate Scenarios Developed from Statistical Downscaling Methods" (Wilby et al, 2004) further discusses these procedures.

Phase 2 made use of previously published statistical downscaling studies to support future climate change projections (Cheng, Li and Auld 2011, Cheng 2014).

Climate Analogues

In the case of extreme temperatures (i.e. average temperature over 30 and 35 C, extreme over 40C) climate change projections were also compared to a "climate analogue." Climate analogues refer to locations in other geographical areas which possess historical climates which resemble in many respects the future climate of the study area. The future temperature regime for the 2050's for the City of Toronto is very similar to the current and historical climate of northern Kentucky. While not an exact comparison – there are significant differences in regional geographical characteristics, for example – rough, "order of magnitude" comparisons can be made to help further determine if climate change projections are in fact realistic and represent potentially "real" climates.

B.4 Determining the Probability of Occurrence of Specific Climate Hazards

Based on the general methodology presented above, the probability of individual climate hazards were determined. The following sections describe in detail how they were estimated.

Extreme Temperatures

Temperatures and temperatures related indices are the most basic and reliable of climate elements, and therefore associated trends and projected changes to temperatures have the greatest confidence. Thresholds are based on previous consultation work from Phase I, IEEE standards for switching and transformer equipment, with some additional consideration from impact studies found in the literature - for example, see (McEvoy, Ahmed et Mullett 2012). The lowest thresholds generally address load forecasting and related factors, while higher temperatures begin to consider direct impacts to equipment.

Historical values were assessed using observations for Pearson Airport for the 1981-2010 normals period. Climate projections were then developed using the AR5 ensemble and RCP 8.5 emissions scenario. For temperature related thresholds which require information of *daily* temperature information, such as heat waves, 40°C maximum daily temperature, or the 35°C average daily threshold, required special treatment and were developed using projections from the CanRCM4 regional climate model (RCM), again using the RCP 8.5 scenario. The "Delta method" was then used to apply the modeled changes in frequency of those days applied to historical averages. It should also be noted that the range indicated for the 40°C threshold is the result of applying two methods, RCM and GCM based estimates, since RCMs are again potentially prone to overestimates due to numerical instability[2], while the GCM method may under-estimate the frequency of extremes due to averaging from large spatial scales. These results were further checked against climate analogues in northern Kentucky, again to serve as a consistency check against model projections to determine if these projected increases were realistic.

Extreme Daily Averaged and Maximum Temperatures

Manufacturers of electrical distribution equipment specify both maximum *one day average* and *peak ambient* temperatures for the operation of transformers and other components. With global warming, it is unsurprising that all thresholds show an increase in event frequency. High temperatures which already occur several times per year increase further in frequency, and a few extreme temperatures which are currently less than annual occurrences (e.g. daily average temperature of 30°C) are projected to become annual events.

The most striking results were noted with some of the highest temperature thresholds. For example, days with peak temperatures of 40°C or greater are extremely rare, with only one incident on record for Toronto's Downtown station[3], and *no* events reported at Pearson Airport during its entire period of record. However, indications are that these extreme heat days may become an annual or near-annual occurrence by the 2050's. Similarly, days with 24 hour *average* temperatures of 30°C or higher are also extremely rare but may become, on average, annual occurrences. However, as with the historical behaviour of lower threshold values, there will likely be some years with several days over the "new" threshold, while other years will have none.

Multi-Day Heat Events and "Warm" Nights

Other measures of extreme heat have been proposed as having a potential impact on electrical infrastructure.

While heat waves, defined as three or more days with maximum temperatures above 30°C, are currently slightly less than annual events, these are expected to increase in frequency to just over 1 per year, on average, into the 2030's and 2050's. The length of a given heat wave may also increase into the future. Regional climate model results suggest that for the 2030's, an average of approximately four (4) consecutive days over 30°C will occur every year, and by the 2050's the estimate is as high as *six* (6) consecutive days over 30°C per year.

So-called "warm nights" have also been implicated in excessive stress on electrical infrastructure (McEvoy, Ahmed et Mullett 2012) through increases in nighttime electrical customer use (i.e. need for continuous use of air conditioning systems), combined with an inability for equipment to sufficiently cool under warm nighttime ambient temperatures. These have increased substantially in recent years, with average of greater than one event per year in the most recent 15 year period of record at Pearson Airport. This includes a record of five (5) warm nights in 2005, as well as the warmest overnight temperature ever recorded in 2006 at 26.3°C. However, while the literature has indicated that the latter element may be important for combined impacts and stress to the electrical system, most workshop participants were indeed quite skeptical that warm nights were an important measure for electrical system impacts, indicating they considered extreme *daytime* temperatures and electrical use as the dominant cause for impacts to distribution systems, rather than warm nights.

[2] Estimated increases in frequency from CanRCM4 were indeed so striking that they were checked against GCM based estimates for consistency. However, even when considering spatial and temporal averaging which will occur with the larger grid spacing and time steps inherent in GCMs, the ensemble still indicated significant increases in extreme heat days well beyond anything within historical experience.
[3] Three (3) consecutive days in July 1936 showed maximum temperatures reaching 40.6°C.

Spatial Geographical Variability

Mapping of extreme temperature days (**Appendix C**) indicate important temperature differences across the city, with temperature differences of 3-5 degrees between the shores of Lake Ontario and northern portions of the city. This is a direct result of the presence of Lake Ontario and its lake breeze, with cooler air from the lake keeping the shoreline and nearby areas cooler than parts of the city further north.

Extreme Short Duration Rainfall

The July 8, 2013 flash flood event in the GTA provided an example of the vulnerability of underground infrastructure to atmospheric events. While this particular case impacted Hydro One infrastructure, it is indicative of possible impacts to similar infrastructure owned and operated by Toronto Hydro. It was also an example of the importance and potential impacts generated by the loss of 3rd party infrastructure on which Toronto Hydro relies, emphasizing the interconnectedness of the electrical grid.

The threshold of "100 mm + antecedent" is based on rainfall accumulations estimated near the failure sites from the July 8th, 2013 event as well as other cases **(see Appendix C)**, although workshop participants felt this threshold might indeed be as low as 60 mm of rainfall. This threshold is in specific reference to high-intensity, localized rainfall events, characteristic of severe thunderstorms during the warm season. These generally last only a few hours in total, with the majority of that rain (over 50%) falling within a 1 hour time period. However, in every case, there was also antecedent rainfall in the preceding week which likely contributed to the overland flooding.

While these events are very difficult to predict even in short term forecasts, historical analyses on global precipitation extremes indicate that, in general, they will increase in intensity with climate change. However, the magnitude of this change, particularly for specific geographical regions, is not well understood (Kunkel, et al. 2013). Extreme, localized rainfall events represent an event type which cannot be modeled directly by GCM or even RCM output, and unfortunately no statistical downscaling studies for extreme thunderstorm rainfall exists for the GTA or nearby regions. However, global trends of historical increases in extreme rainfall are so significant that the climate team chose to increase annual probability score by one to account for this clear increase in thunderstorm extreme rainfall risk

Ice Storms and Freezing Rain Ice Accretions

Damage thresholds were also based on previous forensic work on freezing rain impacts, most notably Klaassen et al. (2003), as well as design requirements in codes and standards (CSA 2010a). These include thresholds for tree damage (15 mm) and for minimum CSA design (25 mm totals ≈ 0.5 inch radial). Freezing rain events represent an example of meteorologically complex events which require special treatment, and hence future projections presented here are based on tailored statistically downscaled results from published studies. Customized data specifically developed for Pearson International Airport were provided courtesy of C. Cheng (2011), using the same methodology employed in Cheng et al. (2011, 2014). Downscaled projections are expressed in *duration* rather than *accumulation amounts* due to the nature of the analysis methods used for downscaling. Climate projections of the parent large scale weather patterns (so-called "synoptic map typing") are based on the patterns and conditions which produce ice storms. For the downscaling work, these weather patterns were linked to the *duration* of freezing precipitation and not *amounts*, since total precipitation accumulation can vary significantly depending on available moisture. The duration threshold is also quite low (6 hours+) due to sample size, since storms of this magnitude or greater are infrequent.

However, these projections can be applied to other measures of ice storm severity given the following considerations:

1. Storms producing amounts on the order of 15 and 25 mm are of part of this "6 hour+" population, and we can therefore use results for the 6 hour+ storms as guidance for what will happen with 15 and 25 mm events; and,

2. Cheng et al. (2011, 2014) consistently showed greater increases in frequency for higher thresholds, hence storms with higher thresholds are expected to increase in frequency as much as or more than storms at lower thresholds;

Hence, changes in 6 hour+ event frequency are expressed as particular values, whereas the greater accumulation events are expressed as “greater than” some value.

Regional Differences in Severity

The severity of freezing rain events, specifically in terms of total ice accretion, tend to be lower for areas closest to Lake Ontario. In contrast to the summer, the lake acts to keep temperatures warmer during the early winter, an effect that appears to have been a factor during the December 2013 ice storm (see **Appendix C**). However, there are also indications from the forensic analyses that older portions of the city, particularly areas with a combination of significant, mature tree canopy cover and older overhead electrical distribution equipment, may be more sensitive to ice storms and are therefore more susceptible to smaller ice accretions.

It is very difficult to determine the return period or annual frequency of the extreme cases, since no events producing greater than 40 mm of total ice accretion have been reported in the GTA. The CSA standard for transmission line design (CSA 2010b) contains return period estimates for radial ice accretion for various locations[4]. Depending ones location within the City of Toronto, estimates for 30 mm ice accretion event (roughly 60 mm of total ice) indicate anywhere from a 1-in-150 to a 1-in-500 year return period event, termed “high” and “low” risk values, respectively, in table 3-2 in the main report. When increases in frequency of large ice storms is taken into account, these produce 35 year study period/”lifecycle” probability estimates of ~25% and ~8%, respectively[5]. However, these values are based on estimated return periods for extremely rare events, and the period of record on which they are based is far shorter than the return periods assigned to these ice accretion values.

Complexity of Freezing Rain Accretion versus Impacts

A myriad of measurements are given for freezing rain ice accretion due its complexity. Accumulations from airports, for example, represent *total* freezing rain amounts and not the thickness of accretions on overhead lines and structures, and hence certain freezing rain amounts can result in very different levels of ice accretion on infrastructure depending on numerous other factors (e.g. time, wind speeds, ambient temperatures). We also note that a significant majority of damage from the December 2013 ice storm was due to tree contacts at accretion thresholds lower than design requirements **(Appendix C)**, hence the inclusion of the 15 mm threshold.

High Winds

High winds can be produced by a variety of storm types and vary greatly in scale, intensity and duration. Design wind speeds found in codes and standards are based on large scale (synoptic) storms, while cases of extreme localized damage tend to occur with thunderstorm winds, including microbursts and tornadoes. This complexity introduces significant challenges when attempting to determine wind speed return periods for engineering design using historical data (Lombardo, Main et Simiu 2009), let alone the challenge of understanding how these might change under future climate conditions. Much like ice storms, wind gusts tend to also be affected by highly localized meteorological and geographical factors, and so meaningful projections cannot be directly extracted from GCMs or even RCMs.

[4] The values provided in the CSA standard (CSA 2010b) are themselves based on the Chaîné ice accretion model. These were felt to be accurate enough to provide estimates of extreme ice storms in the GTA for this study.

[5] Based on climate design table, highest risk locations are Etobicoke and North York, with the lowest risk is in Scarborough (CSA 2010a), the former not surprisingly representing areas which are slightly further away from the lake.

The 70 and 90 km/h thresholds are based on practitioner consultation from Phase I as well as forensic analyses conducted for Phase II (**Appendix C**). The highest threshold, 120 km/h, is based on IEEE design standards for switch gear and transformers, as well as other impact thresholds work, for example the EF-scale and McDonald and Mehta (2006). Climate change projections for the 70 and 90 km/h thresholds were obtained from statistically downscaled results in the published literature (Cheng, Li et Li, et al. 2012, Cheng 2014) using statistical downscaling methods similar to those used for freezing rain, while projections for 120 km/h threshold were not available.

The statistically downscaled results indicate increases for both thresholds analyzed here. Cheng et al. (2012, 2014) also indicated that increases in frequency of wind gusts were consistently greater as thresholds also increased (e.g. 80 km/h gusts increased more than 70 km/h gusts), but did not conduct analyses for thresholds greater than the 90 km/h due to small sample size.

Tornadoes

Tornadoes are small scale, isolated events, and hence the only available historical data are records of observations of their occurrence and/or resulting damage. Probability scores for EF1 and EF2 tornadoes were calculated based on historical records of occurrence within the City of Toronto from the most recently available 70 years of observational data. Historical data prior to this was deemed too unreliable to contribute to statistics in a meaningful fashion. This inconsistency also renders historical trend detection nearly impossible[6]. Their localized and complex nature also prevents the development of meaningful climate projections through any of the methods described here, including GCM or RCM output as well as statistical downscaling.

As with extreme temperatures, lightning and ice accretion, the northern portions of the city such as the North York and Rexdale (northern Etobicoke) areas exhibit a higher risk of tornadoes historically, again mainly due to the effects of the Lake Ontario lake breeze, but this does not exclude the occurrence of tornadoes in and around the downtown core.

Two different intensity levels were chosen due to important differences in their impacts. Research on historical events indicated that concrete utility poles and other more resilient infrastructure only fail in EF2 or stronger tornadoes, and hence these were investigated separately to determine relative risk.

High Impact/Low Probability Events: Probability Estimates and Their Interpretation

Tornado probabilities were subject to further analyses beyond those used for most other climate elements. Probability scores in Table 3-2 of the main report reflect the probability of occurrence for a *single point*; however, since these values are extremely small, a different statistical perspective was needed to better represent the type of risk posed by tornadoes. The City of Toronto has recorded five (5) F-2[7] tornadoes on two separate days since 1900, with a possible sixth case in 1976 in North York. Hence, over the 35 year life cycle study period, there is a 46% to 61% chance that a weather event producing one or more EF-2 tornadoes will strike somewhere within the City of Toronto. While the probability of a direct impact to a specific point or location is extremely small, the likelihood of a significant event *somewhere* in the city between 2015 and 2050 is in fact considerable, and could entail catastrophic impacts to a portion of the city's infrastructure.

Lightning

As with all other climate elements, lightning can vary significantly in intensity, with the same storm producing different lightning strikes with amperage values varying by several orders of magnitude. Even

[6] However, some very recent work in the United States may finally be revealing changes in tornado climatology potentially associated with climate change in the form of increased *variability* in occurrence[6] (Brooks, Carbin et Marsh 2014).

[7] The so-called "Enhanced" Fujita, or EF-Scale, has only been used in Canada as the official replacement to the F-scale since 2013; however, the EF-scale is intended to be compatible with F-scale ratings in the historical record, and so references to tornadoes using the F-scale can, for the purposes of this report, simply be considered as storms of equivalent intensity.

for a single thunderstorm event, there now exists a great deal of data currently available for use in analyses and even forecasting of lightning occurrence, particularly following the establishment of the North American lightning detection network in the late 1990's, and more recent "total lightning" detection networks being installed in the GTA for meteorological monitoring for the upcoming 2015 PanAm games. It is suggested that Toronto Hydro investigate this data to better understand how lightning interacts with the electrical distribution system, such as investigation of significant lightning events (e.g. July 21 & 22, 2002) to determine why and how they generated so many impacts.

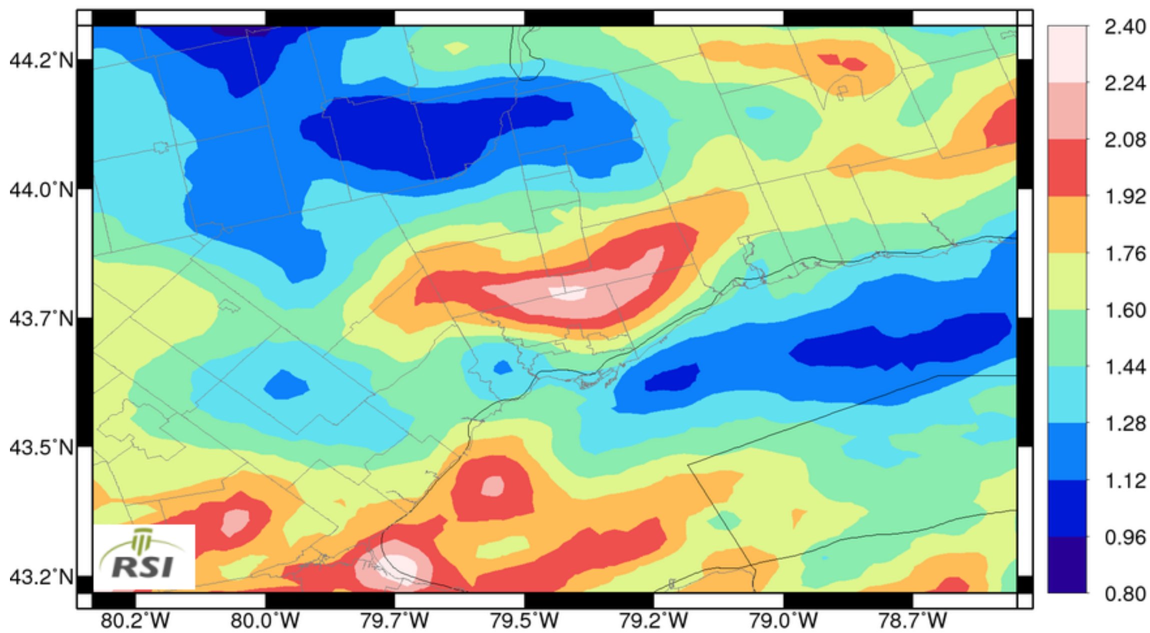
Investigation of New Probability Scoring Methodology

Lightning probability scores differ from Phase I due the changes in the method used to calculate probability values. The annual average frequency of cloud-to-ground lightning strikes varies across the city from under 1.12 to over 2.24 lightning strikes per square kilometer. The highest frequencies are seen in the northwest portions of the city, while the lowest are seen in southern Etobicoke (see Figure B-7). However, each individual strike will only affect a very small area. Hence, the probability of impact was estimated using representative "target sizes" (i.e. areas which represent the usual footprint of a given piece of infrastructure). A further assumption was tested assuming that lightning strikes would need to be within 25 meters of a piece of overhead infrastructure to produce negative impacts. The resulting probability scores were felt to be more representative of field conditions, particularly when considering the frequency of lightning impacts reported by Toronto Hydro (**see Appendix C**). These were also weighed against mounting evidence that lightning occurrence will increase in frequency with climate change, for example (Romps, et al. 2014), but by an uncertain amount[8].

Using two different "target" sizes provided by AECOM representing large (0.015 km^2) and small municipal (0.0001 km^2) transformer stations, probability of impact were calculated and compared, with and without the assumption of a 25 meter radius of impact. The results are provided in Table B-2 below.

Figure B-7 Lighting Distribution in Greater Toronto Area for 1999 – 2008 period, Lightning Strikes / /km^2•yr)

[8] Romps et al. (2014) indicated a potential increase of ~50% in total lightning strikes in the continental United States by the end of the century. However, while their methodology proved to be quite robust when compared to observational data, there was no assessment of GCM error in recreating the indices which drove this increase. Their index and model also appear to have difficulty with lake breeze related convection, which is of great importance for Toronto's lightning climatology. Hence, the RSI climate team chose to not apply these percentages as there remains too much uncertainty in how global climate change will impact lightning frequency in the Toronto area specifically.



44.2°N
44.0°N
43.7°N
43.5°N
43.2°N
80.2°W
80.0°W
79.7°W
79.5°W
79.2°W
79.0°W
78.7°W
2.40
2.24
2.08
1.92
1.76
1.60
1.44
1.28
1.12
0.96
0.80
RSI

Table B.2 Lightning Strike Probabilities Transformer Stations

Target Type	Annual Lightning Frequency (km^{-2})	Annual Probability Score (2050's)	Study/"Lifecycle" Period Probability Score (2015-2050)
Large Transformer Station	1.12	1	5
Large Transformer Station	2.24	2	6
Municipal Transformer Station	1.12	0	2
Municipal Transformer Station	2.24	0	3

Snow

Snowfall thresholds were chosen following the second workshop and are intended to address "nuisance" events, such as those which require the application of deicing agents (5 cm+) and those leading to restricted to site access (10 cm+). The group chose to focus upon nuisance events at the "lower end" of the snowfall accumulation spectrum, rather than extreme snowfall events, since overhead systems were not considered by workshop participants as being sensitive to direct snow loading. Historical data indicate that the total number of days exceeding these thresholds are decreasing, as expected with global warming, but not at all rapidly enough to consider snow a "disappearing" hazard. In addition to this, and in contrast to days with small snowfall totals, days with extreme snowfall will continue to occur well into the future, and may in fact *increase* in intensity with further warming (Kunkel, et al. 2013). Hence, days in which snow will pose a hazard to infrastructure will continue well into the coming decades, even with continued warming.

Frost

Participants at the second workshop also indicated frost depth as being a concern for civil infrastructure, particularly following the extreme cold experienced during the 2013-14 winter season. As with other cool season hazards, the frost free period is expected to increase in length, which will result in less frost penetration on average, although occasional extremely cold winters will continue to occur well into the future. Frost depth calculations were not conducted for this project due to time and resource constraints, as well as significant variability associated with frost depth under the same atmospheric conditions. The latter is impacted by soil moisture, thermal conductivity, snow cover, and several other factors which vary greatly across the city. However, if frost heave is considered an important risk, further study could be conducted, using the 2013-2014 winter season as an example case study.

Complex Interactions

Complex interactions are generally defined as interactions which generate negative or unwanted impacts to infrastructure but which are the result of a *sequence* of events involving both climate and human factors. For the sake of simplicity, we have considered most climate elements in isolation. As the forensic analyses indicate, however, most real-world climate impacts are often attributed to one dominant element but with additional impacts from other simultaneously occurring hazards.

High Humidity Near-Zero Winter Environments

This complex interaction type was identified through both workshops and forensics work, and their occurrence appears to result from a *sequence* of events involving a combination of minor ice accretions followed by the application of de-icing agents. These are characterized by multi-day periods in which temperatures are near zero degrees, often "crossing" the zero degree line multiple times, and include multiple periods of freezing or frozen precipitation. Ice accretion may be from a combination of freezing rain, wet snow or rain-on-snow “re-freezing”, with possible *additional* accretion from fog which is often present between periods of precipitation. These very moist conditions are then coupled with de-icing agents to cause short circuits, resulting in pole top fires and other incidents associated with short circuiting of insulators and switch gear.

Such a complex events entail the sequential occurrence of several meteorological factors coupled with human factors and are therefore impossible to project using the current set of climate change projection techniques. However, having identified these conditions, their occurrence could be monitored and even anticipated several days in advance using a combination of current conditions and short term weather forecasts, allowing for the mobilization of operational resources. The January 31st to February 3rd, 2003 event described in **Appendix C**, and a similar event which was identified for the transmission sector “sister” PIEVC study (January 2000) can be used to form the basis of pattern recognition for future events of a similar nature.

Tree Growth, Disease and Pests: Implications for Overhead Infrastructure

The second important complex interaction identified by our analysis entails the impacts of environmental changes affecting tree growth and health, affecting their resiliency to climatic loading. Higher average temperatures are expected to extend the growing season. This will likely result in faster tree growth and necessitate more spending on right-of-way maintenance, as well as possibly increasing tree vulnerability to wind and ice loading. The impacts of new and/or exacerbated disease and pest conditions can also increase tree vulnerability to damage, with the December 2013 ice storm and impacts on emerald ash borer infested trees being an example of this increased vulnerability. The complex interaction between accelerated growth rates, disease and pest regimes, and the resulting changes in vulnerability to adjacent infrastructure have only recently been identified and are not well understood, but should be subject to further study.

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Brief Forensic Analyses of Weather Related Power Outage Events

C.1 Introduction

To better understand the nature and magnitude of climatic and meteorological events responsible for impacts to Toronto Hydro's electrical distribution system, as well as neighboring LDCs, RSI staff conducted forensic analyses of events generating significant impacts to the system. Information on the nature and extent of those impacts was compared to meteorological data to understand the nature and magnitude of atmospheric loads and conditions associated with these impacts. The analyses below consist of what can be termed either "single incident" or "cross-incident analyses," the former consisting of a "deep dive" into an individual events (listed in **Table C.1**), while the latter consists of the inter-comparison of numerous similar events to help determine commonalities.

In particular, events that were deemed meteorologically complex or multi-causal in nature, as well as meteorological events representing instances of impact thresholds, were selected for further assessment under "single incident" analysis to help refined our understanding of the thresholds at which impacts begin to occur, and what the causes and drivers of those impacts might be. Winter storms (including freezing rain events), summer thunderstorms, and a high heat case were evaluated for more detailed analyses. Other cases, such as fall season high winds, were evaluated under "cross-incident" analyses, for the purpose of evaluating and cross-checking thresholds determined from other sources (e.g. literature and practitioner interviews).

Several data sources were consulted for both meteorological and infrastructure impacts information. The former included data from Environment Canada's national climate data archive, Toronto Region Conservation Authority (2014) precipitation data, consultant reports (Cole Engineering 2013), as well as remote sensing data where appropriate. Impacts data were provided directly by Toronto Hydro, as well as outage incident press releases, newspaper accounts, and internal report (where available). Events which underwent detailed analyses are listed below in **Table C.1**.

C.1.1 Event Types and Relation to Impacts

Any number of climate and weather related events are capable of producing unwanted interactions with power distribution infrastructure. Direct impacts from severe winds, ice accretion, heavy/wet snow, extreme heat and lightning can directly overload support structures and conductors, as well as adjacent vegetation, which is also prone to failure, causing secondary impacts. Underground infrastructure is sensitive to flooding and longer term processes, such as enhanced corrosion through seepage and penetration of deicing agents. For each hazard, there are generally a small sub-set of mechanisms which can produce them. High winds during the warm season are associated with severe thunderstorms (including downbursts, microbursts and tornadoes), which tend to be intense but localized, whereas should season and winter severe winds are associated with large scale low pressure systems (so-called "synoptic lows"). Winds associated with these events are more widespread and can last for several hours to more than a day. Similarly, precipitation events are generally associated with thunderstorms during the warm season and low pressure systems in the cool season (snow storms, ice storms, etc.). It should become quickly apparent that several event types can occur simultaneously, resulting in multiple cause power outage events.

Identification of event type is critical in understanding what types of impacts to expect at different times of year, including duration of the event, potential challenges for response and maintenance, presence of simultaneously occurring hazards, and for some event types what antecedent conditions to monitor to help anticipate or forecast weather related impacts. During the late spring and summer, for example, a number of significant thunderstorm events tend to be proceeded by high temperature and humidity combinations which themselves may have generated impacts on the system. While individual events are indeed complex, infrastructure operators can begin to understand the antecedent conditions to help increase readiness for such events.

Event type identification is also critical to climatological analyses and the development of adaptation responses. More localized, short duration events present significant challenges for assessing future climate vulnerability and risk, but less complex climate elements, such as temperature, are far less difficult to analyze, and confidence in both the consistency of historical data as well as certainty in projected trends are much greater.

Adaptation responses, particularly those regarding maintenance and operations, must take into account the nature of the events generating impacts. How much lead time can one expect for storm warnings, if any? What hazards may be posed to repair crews, or restrict access to damage locations? For example, a number of recent press releases indicated that full repair efforts have been postponed based on the timing of high winds, with crews waiting for the “worst to pass” before executing major restoration efforts (see “Superstorm Sandy” analysis below). More sophisticated operations and management actions such as these are critical to optimizing response to severe weather events.

C.1.2 Brief Note on Impacts Data

Staff at Toronto Hydro kindly provided outage incident data for this analysis, which proved invaluable for determining the types and magnitude of events which were responsible for significant power outage events. However, this type of cross-disciplinary forensic analysis was not the original intent of the failure database, and as such there were a number of challenges which presented themselves when using the data.

Most notably, it became clear that data collection was inconsistent throughout the period of record. While the database contains events from the years 2000 to 2013 inclusive, earlier events have dozens of reports per date, while more recent major outage events do not. In 2013, the July 8th flood and December 21st-22nd ice storm, which Toronto Hydro staff indicated were among the worst in their history, have very few listings in the database. This is likely due to changes in reporting practices, which apparently began in 2007 judging from the frequency of weather events with 20+ reports each, but this requires confirmation Toronto Hydro staff.

This emphasizes the need for the standard forensic practice of consulting and comparing multiple sources of data. For example, impacts data can be used to indicate if event intensity, such as high winds, could have been significantly higher than meteorological measurements may indicate. Conversely, meteorological data can be used to either guide and/or refine the search for impacts data, or even correct coding or other errors in impacts data.

C.2 Toronto Hydro Outage Data

As indicated above, outage data from Toronto Hydro were interrogated to identify significant outage events which could be used for further study. Days with 20 or more reports were identified, and these were further refined by checking for potentially related reports on days before and after identified event dates. While it is fairly clear that data from 2007 to 2013 were collected under different reporting requirements, 2000-2006 appear to be consistent, and so data for this period will be evaluated here.

A total of 46 weather events were identified with this methodology. Just over half (54%) of these events occurred over fairly extended periods of 12 to 48 hours; this has implications for maintenance and repair response measures. For fall wind storms and winter precipitation events, this quite literally meant several consecutive hours of either high winds or precipitation generating impacts, while for summer events this likely represents two or more episodes of thunderstorm activity within a one to two day period.

C.2.1 "Worst" Years

In terms of the "worst" years, we have two measures; total number of events, total number of damage reports for these events, and number of damage reports per event. The years 2000 and 2005 are tied for the most events in a given year (9). In terms of total reports for all events combined, 2000 has the highest at 6—followed by 2003. In terms of average event severity, the total number of reports was divided by the number of events in a given year as a rough measure of "average" severity for a given year. The year 2003 had the highest average, with an average of just over 84 reports per event. Even though 2000 and 2005 contain single major events, their averages fall well below those seen in 2003, 69 and 56 reports per event respectively.

The year 2000 followed two main themes. A series of severe winter storms in February were responsible for multiple reports and were characterized by either freezing rain or heavy wet snow and rainfall combinations, both characteristic of "warm" winter storms producing heavy precipitation at temperatures near or at 0°C[1]. This was followed by late spring to summer severe thunderstorm events, including the May 12-13, 2000 event, as well as a thunderstorm event on July 14, 2000, which generated over 100 reports through mainly lightning related damage.

The year 2005 was characterized by high heat and humidity during the summer months, which either directly contributed to infrastructure underperformance as well as severe thunderstorm events, most

[1] At temperatures at or just below freezing, atmospheric water content is at its highest while still being able to support ice formation; hence temperatures near zero are associated with either freezing rain or high density, wet snow capable of physically coating and loading overhead lines and trees.

notably the August 19th, 2005 storm. This was followed in the fall by a series of wind storms which produced scattered outages throughout the GTA, which was among several areas across Ontario which were impacted by intense fall windstorms (e.g. over 100,000 Hydro One customers lost power during the November 6, 2005 synoptic storm; Hydro One 2005).

Finally, in 2003, Toronto Hydro was impacted by a similar combination of event types, with two winter storms in rapid succession in February, followed by severe thunderstorm activity during the late spring and summer, followed by large scale wind events from late September to mid-November.

All of the so-called "worst" years identified here have the following in common:

- Repeated events, often with only days between similar types of incidents
- Two or three "modes" of high impact weather events in the same year, specifically:
    - "warm" winter storms, meaning they were associated with temperatures at or just below 0°C with some combination of heavy snow, freezing rain or even rainfall mid-winter;
    - Severe thunderstorms and high heat and humidity during the summer;
    - Multiple fall season large scale (synoptic) wind storms;
- One major event which produced over 150 damage reports

These findings can help with better planning and anticipation of particularly high impact years. For example, periods of very high heat and humidity should be watched closely, as they are occasionally followed by severe thunderstorm events when the heat "breaks" with the passage of a cold front or other air mass change. Fall and spring large scale wind storms will occasionally occur in series, as occurred between September 29th and November 13th 2005[2], repeatedly impacting the same area. These findings appear to be consistent with recent experiences; in 2013, Toronto Hydro suffered two major weather related outage events, one in the summer from a severe thunderstorm event producing extreme rainfall, followed in the winter by a freezing rain event.

It may also be possible to anticipate a particularly severe damage year since the "major" events producing over 150 reports tend not to occur in isolation but usually occur in years with a number of less severe but still significant events, although the consistency of this pattern requires further research.

C.2.2 "Worst" Events for 2000 to 2006 Period

The two events with the greatest number of reports, May 12-13, 2000 and August 19, 2005, were both subject to detailed analyses. Another three events (Jan 31-February 4, 2003; July 14, 2000 and July 21-22, 2002) produced over 100 reports, with September 19, 2003 coming very close at 99 reports.

What is of particular interest is the number of severe thunderstorm related reports which were accompanied by mainly lightning related outages. Even for storms which included extreme rainfall and high winds related impacts, lightning appeared to be the dominant factor in producing outages. The July

[2] A fourth synoptic storm occurred on November 15 to 16, 2005 but did not cause significant impacts to Toronto Hydro's infrastructure, instead tracking to the north east and affecting Georgian Bay and the "Nickel Belt," causing over 50,000 Hydro One customers to lose power.

21-22, 2002 event is particularly noteworthy. Although we do not have detailed lightning information, such information is available from the national lightning detection network, and the frequency and amperage of lightning experienced during this thunderstorm series could be investigated to determine what made this particular lightning storm so damaging to the system in comparison to any number of other events. A summary of all events identified through this method is provided in **Table C.2**.

C.3 Fall and Winter Storms

C.3.1 December 20-22, 2013 Ice Storm

The December 2013 ice storm in south central Ontario has been deemed the worst ice storm in Toronto Hydro's history in terms of impacts to the city's distribution system. It is estimated that at the peak of event during the overnight hours between December 21st and 22nd, ~300,000 customers were without power. The most recent estimates of total damage incurred by Toronto Hydro's distribution system has been placed at nearly $15 million, specifically for restoration and repair (Toronto Star: March 31, 2014).

The storm also impacted several other adjacent LDC's, including:

- Enersource (Mississauga), 91,000 customers affected (Mississauga.ca 2014);
- Hydro One Brampton, 15,500 customers (Brampton Guardian, Dec 30, 2013);
- PowerStream (York Region[3]) 92,000 customers (Markham Economist and Sun, December 31, 2013);
- Veridian (Pickering/Ajax/Port Hope) 40,000 (Veridan Connections Press Release, Dec 22, 2013);
- Whitby 13,000 (Oshawa This Week, Dec 22, 2013)
- Oshawa Public Utilities Company ~30,000; and,
- Rural areas of Clarington (Hydro One) ~46,000 (Ajax News Adviser, Dec 23, 2013)

Meteorological data from both Environment Canada and Toronto Region Conservation Authority stations were analyzed to estimated ice accretion totals and rates in and around the GTA, which were then compared to impacts on electrical distribution infrastructure in the area.

C.3.1.1 Impacts and Meteorological Conditions: City of Toronto

Figure C.1 compares estimated ice accretion values at Pearson and Buttonville Airports with the total number of customers affected reported by Toronto Hydro. While ice accretion values were not directly reported by any of the stations evaluated, they can be estimated by combining hourly observations of precipitation type with daily rainfall totals. Freezing rainfall and drizzle totals were estimated by first determining the fraction of precipitation falling as freezing rain or drizzle (since liquid rainfall and snow were also reported on some days). Accretion rates were then weighted by precipitation type (1 for rain, 0.5 for moderate rain, and 0.1 for drizzle, based relative accretion rates from Klaassen et al. 2003), which were then further developed into estimated hourly average accretion rates. These were then summed for each day between December 20th and December 23rd for both Pearson Airport and

[3] PowerStream also suffered the complete outage of their website, which had not been designed to receive the traffic volumes which it encountered during the event (Markham Economist and Sun, December 31, 2013).

Buttonville Airports, the only locations near the City of Toronto for which hourly observations of precipitation type were available. Given that several locations experienced both above zero temperatures and liquid precipitation during the multi-day period under analysis, and that ice accretion on overhead structures, lines and trees is further affected by wire or branch diameter and surface characteristic, it is likely that estimated multi-day ice accretion estimates are *over*-estimates of true accretion values. This will be taken into account during the discussion of impacts.

Ice accretion totals for the 3 day period are over 30 mm for Pearson Airport and nearly 35 mm at Buttonville. A review of hourly temperatures at both airport for the same time period (not shown) also indicate that Pearson Airport was above zero for several hours longer than Buttonville, implying that less freezing precipitation accretions may have been retained there than at Buttonville. A comparison of photographs taken following the storm, both of ice accretions on different objects, as well as the apparent severity of tree damage to areas near the two airports provide evidence that ice accretions immediately north of the City of Toronto incurred ice accretion amounts several millimeters greater than those experiences in northern portions of the city (**Figure C.2**).

The relative impacts of temperature regimes become readily apparent, however, when ice accretion estimates are isolated to include only freezing rain totals beginning late morning on December 21st, excluding accretion contributions from the December 20th to 21st overnight precipitation episode. Ice accretion values become only 13 mm for Buttonville and *25* mm for Pearson. This implies to important elements for understanding how ice accretion values evolved in different portions of the GTA, particularly:

- Higher than 13mm ice accretion values for municipalities north of Toronto cannot be explained without including precipitation amounts from the earlier December 20th-21st episode;
- Lower than 25 mm ice accretion values near Pearson Airport likely cannot be explained without considering periods of >0°C temperatures, combined with the effects of liquid (non-freezing) rain and drizzle

Estimate ice accretion values on the order of ~20 mm were present when outages began, with amounts of 18 and 23 mm at Pearson and Buttonville respectively just prior to first report of 8,500 outages. Press releases indicate that this initial damage was indeed focused in northern and northeastern portions of the city (Toronto Hydro Press Release; December 21, 11:58 PM); accretion values estimated from these airports are likely representative of those experienced in the first areas suffering from widespread power outages. Rounding down to allow for some ice accretion losses due previously discussed factors, a range of 15-20 mm are likely responsible.

To better understand conditions in and near the downtown core versus surrounding portions of the city, hourly temperatures at the Downtown meteorological station (located at the University of Toronto campus on Bloor Street) and Toronto Island's Billy Bishop airport, were compared to those at Pearson Airport (**Figure C.3**). Radar imagery (**Figure C.4**) indicates that precipitation elements were moving very rapidly (over 100 km/h) during the freezing rain event, hence hourly precipitation reports at Pearson Airport are likely representative of the occurrence or non-occurrence of precipitation conditions at stations located less than 20 km to the ESE, where manned observations of precipitation type are not available. Precipitation reports from Pearson Airport were therefore superimposed on temperature plots to indicate when precipitation was occurring, and more importantly to imply whether or not precipitation was falling as liquid rain or freezing rain for downtown locations for a given hour.

Figure C.4 shows hourly temperatures at the three Toronto locations, implying that the city's downtown core likely received much less freezing rain than surrounding areas (the so-called "horseshoe" of former suburbs), and that accretions from December 20th and most of December 21st would have been unable to remain on exposed surfaces. However, a period of particularly heavy precipitation overnight between December 21st and 22nd correspond with temperatures below freezing, with both downtown stations falling below 0°C between 10 and 11 PM on the night of the 21st.

Toronto Island Airport reported 17.7 mm on December 21st and 13.9 mm on December 22 and the Downtown station reported 17.0 mm and 14.3 mm, respectively. Assuming the majority of precipitation on December 22nd fell as freezing rain, with some additional contributions from precipitation late in the evening on December 21st, ice accretion values in the downtown core were likely on the order of ~15 mm, compared to estimated values in excess of 25-30 mm or more estimated for northern portions of the city and adjacent municipalities. The implication, however, is that severely impacted portions of the city of Toronto near the downtown core may have seen significantly smaller ice accretion values than other parts of the city but still suffered from multi-day power outages.

Estimates of ice accretion rates at Pearson and Buttonville airports, along with the severity of impacts in the downtown core, which likely only saw ~15 mm, suggest that the final hours of the freezing rain event produced much more rapid ice accretion rates than earlier phases. Between 11 PM December 21st (when downtown stations were below 0°C) and 9AM the following morning, only 7 hours of freezing rain was observed at Pearson Airport. Even with significant averaging inherent in ice accretion rate estimates calculated in **Figure C.1** for Pearson and Buttonville airports, freezing rain ice accretion rates peaked during the early morning hours of December 22nd, estimated at 2.13 mm/h at Pearson and 1.25 mm/h at Buttonville, compared to estimated hourly rates on preceding days (0.79 and 0.95 mm/h for Pearson; 0.92 and 1.19 mm/h for Buttonville). A review of radar imagery for that time period (**Figure C.3**) indicates that a particularly heavy area of precipitation, associated with a small scale meteorological feature, tracked over the GTA and surrounding areas in the early morning hours of December 22nd. This corresponded with the rapid increase and peak in reported outages, and was likely responsible for a large portion, if not the majority, of ice accretions experienced in and around the downtown core.

Immediately following the ice storm, one spokesperson for Toronto Hydro indicated the worst damage appeared to be following highway 401, but this was prior to knowing full extent of damage in Scarborough (Toronto Star; December 23, 2013). Outage maps of the city the following day showed a clear delineation of much less severe impacts south of Bloor Street versus areas north and east of the downtown core, however a lack of both detailed impacts data and/or meteorological observations, particularly for Scarborough and East York, complicate better diagnoses of the reasons for these differences. At these scales, there could be a complex interplay between local topography, infrastructure characteristics, tree canopy extent and/or health, as well as small scale meteorological elements (e.g. there may have been marked small scale differences in temperature gradients or locally enhanced precipitation). Without higher resolution data, all potential causes for these boundaries remain speculative.

C.3.1.2 Impacts and Atmospheric Conditions: Durham Region LDCs

Analyses of impacts to LDC's east of the city of Toronto are complicated by a lack of both detailed impacts information as well as aforementioned meteorological observation data. Only daily precipitation totals and hourly temperature data are available for Oshawa Airport, and only a small number of TRCA stations were available to provide temperature data for the Ajax and Pickering areas, but did feature high sampling rates (5 and 15 minute intervals). However, given the characteristics of damage reported by the press, it can be easily surmised that a significant amount of ice accretion occurred in the region.

A review of hourly temperature data for Oshawa Airport indicate that for the 72 hour period beginning at 4 PM on December 20th, there were only ~4 hours in which temperatures were at or just slightly above 0°C, specifically between 11 PM December 22nd and 2 AM December 23rd. This suggests that the majority of the precipitation on December 21st and 22nd, with daily totals of 17.6 mm and 10.3 mm, respectively, was likely freezing rain. Accretions could have also included some of the 8.1 mm reported on December 20th, where temperatures remained below 0°C after 4 PM. Similarly, temperature data from a TRCA weather station at Bayly and Church in Ajax (**Figure C.6**) indicate ~3.5 hours mid-day on December 21st, for which temperatures were above 0°C for the same time period, as do temperature data for the Brock West Landfill site, north of Pickering, for ~3.3 hours (TRCA 2014). The overnight temperature spike indicated at Oshawa Airport on December 21st and 22nd also shows up clearly for these two stations, but remains *below* freezing. Temperatures remained below 0.5°C for all three sites, even with sampling rates of 15 and 5 minutes for the two TRCA sites. Hence, when considering temperature conditions associated with the event, freezing rainfall totals in the ~25-35 mm range are likely for portions of southern Durham region.

Restoration times were checked in local newspapers and available press releases from LDCs (mainly Veridian) to ascertain how quickly Durham region LDCs recovered from the event when compared to Toronto Hydro. A rough benchmark of 90% restoration was used to compare the LDCs and using the morning of December 22nd as a start time for full restoration efforts:

- Veridian (Ajax, Bowmanville, Newcastle, Port Hope), restored by 8 PM December 24th, 2.5 days;
- Oshawa PUC, restored mid-day December 23rd, ~1 day;
- Whitby Hydro, fully restored by December 24th, 1-2 days;

These are compared to Toronto Hydro, which required more than **5** days to restore power to 90% of customers affected by the event. The effects of scale on Toronto Hydro's distribution system, as well as increased vulnerability from aged infrastructure, aged trees adjacent to overhead lines, and difficulty servicing and accessing equipment cannot be underestimated. There are also likely differences in the ratio of response capacity (e.g. number of personnel versus number of customers) as well as shear geographical area to be covered. Significant differences in recovery time appear to be an excellent example of how logistical challenges for larger metropolitan LDCs can result in marked difference in vulnerability when compared to much smaller LDCs servicing small cities and rural areas, in spite of the fact that Durham Region appears to have, on average, been impacted by similar to possibly higher ice accretions than large portions of the City of Toronto. Overall, at least in the case of the December 2013 ice storm, larger LDCs appear to be more susceptible to ice storms than smaller ones, likely due to a combination of factors.

Veridian indicated that by noon on December 26th, only ~1,700 of the original 40,000 customers who had lost power remained without service (DurhamRegion.com, Dec 27, 2013), and that these mainly consisted of particularly difficult to repair elements, such as backyard supply lines. Similar comments were made by Toronto Hydro staff regarding back-lots which needed to be serviced and which were quite common in some parts of the city, although indications are that these will be eventually phased out.

Tree impacts were again named explicitly as the cause of much of the damage in Durham Region (Ajax News Adviser; December 23, 2013). On December 26th, Oshawa PUC continued to report problems with tree branches falling on lines generating new damage, and on the same day a statement by utilities officials in Whitby indicated that recent snowfalls had added more weight to ice covered tree limbs, and warned of an increasing the risk of breakage and the potential for new damage (Durham Region.com, December 26, 2013). These concerns are again similar to those expressed by Toronto Hydro and indicate an aspect of ice storm damage which should be considered in response and recovery methods.

C.3.1.3 Case Specific Findings December '13 Ice Storm:

While ice accretion values likely approached or even slightly exceeded minimum CSA design requirements (CSA 2010) for overhead systems for small portions of the city of Toronto, Durham Region, and other areas, it appears that the vast majority of damage inflicted on overhead distribution lines during the ice storm was due to the impacts from falling tree limbs. Immediately following the ice storm, tree damage was indicated as "worse than originally anticipated" (TH Press Release, Dec 23, 2014, 3 PM) in spite of what has since been termed aggressive tree trimming programs in place prior to this event. At least two municipalities, Brampton and Whitby, also indicated concerns that emerald ash borer (EAB) affected trees posed particular risks due to their weakened state. Tree impact damage continued for several hours to several days after significant ice accretion ceased. One line worker described how falling tree limbs continued to damage lines even during maintenance, and that repairs had to be redone at some locations (Toronto Star: December 23, 2013). This is also consistent with continued tree fall observed by one of the authors (S. Eng) during the mid and late-afternoon of December 22nd in central Etobicoke area, again several hours after significant ice accretions had ceased.

It is hypothesized that continued damage may have been due to both continued light freezing and frozen precipitation which continued periodically at various locations through December 22nd and 23rd, and gradual loss of fiber strength from prolonged loading.

During the recovery effort, there were notable. increases in estimated restoration times as efforts progressed. Estimates in earlier press releases indicated restoration times of 12-16 hours were expected, while *eventual* restoration times, particularly for the remaining 10% of customers to be restored, were in excess of 5 days.

Total ice accretion amounts for areas surrounding the City of Toronto were likely much higher than those experienced in the downtown core and surrounding areas. In areas within Durham and York Regions, temperatures generally remained cold enough to maintain freezing rain ice accretions which began as early as the afternoon of December 20th. As one approached the downtown core of the City of Toronto, the event transitioned to one better characterized as a relatively short duration but fairly intense period of freezing rain, the majority of ice accretions and impacts occurring during the overnight and early morning hours between December 21st and 22nd, rather than multi-day ice accretions apparent in areas surrounding the city. These characteristics of the freezing rain event need to be understood when considering differences in both impacts and vulnerability of Toronto Hydro's distribution network when compared to LDCs in adjacent municipalities.

Press releases in the days following the event placed a clear emphasis on electrical stand pipe damage to individual homes in Toronto Hydro press releases. It is hypothesized that, as ice accretion amounts increase, more and more elements of the electrical system are damaged, hence repairs become exponentially more difficult to execute, as impacts progress from isolated large branches on lines to entire trees, and as a higher percentage of individual residences suffer damage, as indicated by the widespread damage to individual residential standpipes suffered in the Toronto Area. Similar impacts were noted during the January 1998 ice storm in Quebec, where all not only transmission corridors were severely damaged, but also individual residential lines, making recovery especially challenging due to numerous repairs on the individual customer level.

A lack of manned observations of precipitation type south and east of Pearson Airport was found to be frustrating to the investigation, particularly for **Toronto City Center** and **Island Airport** stations as well as **Oshawa Airport**. While useful findings were developed based on precipitation estimates and proxy analyses (e.g. use of temperatures to imply precipitation type), manned observations confirming precipitation type and accumulation rates would greatly assist with diagnoses of conditions in downtown Toronto as well as for Durham Region LDCs. Impacts data in the form of outage timelines and descriptions of damage could then be combined with more representative meteorological data to compare relative sensitivities of adjacent LDCs to ice storm conditions. A lack of any meteorological observations for East York and Scarborough were particularly frustrating, given apparent (and as of yet unexplained) boundaries in impact severity for these portions of the city.

Similar problems were encountered with TRCA data. While some locations provide precipitation data during the winter, all were well north and west of both Toronto's downtown core, as well as populations centers in Durham Region impacted by the storm. This indicates the need for improved monitoring of winter precipitation in populated areas of the GTA, since differences in impact severity between different municipalities is difficult without detailed observational data on precipitation characteristics.

A significant meteorological component of the event, especially for areas in and around Toronto's downtown core, appears to have been a particularly heavy episode of precipitation during the early morning hours of December 22nd associated with a small scale meteorological feature. This implies that for high impact winter events, even those associated with large scale processes, difficult to forecast smaller scale[4] meteorological phenomenon, perhaps only a few dozen kilometers in physical extent and affecting a given location for only a few hours, may still play an important role in generating impacts. This emphasizes the need for continued monitoring of weather forecasts and meteorological remote sensing data such as radar, since the onset of impacts from these types of phenomenon can be quite rapid and are akin to severe thunderstorm events during the warm season.

In addition to Toronto Hydro, several other LDCs also indicated marked differences in the severity and extent of impacts within individual municipalities. Enersource outage maps, for example, showed particularly severe impacts in the northwestern portion of Mississauga. Veridian indicated that southeastern portions of Ajax suffered more damage and were more difficult to restore, mainly due to aged trees characteristic of the area (Ajax News Adviser; Dec 23, 2013), and similar reports of particularly heavily affected areas were also noted for Pickering (DurhamRegion.com; Dec 24, 2014), although a specific cause for these difficulties was not given. More detailed studies of these localized disparities in impacts would be extremely informative. These would likely consist of surveys and could include a review of individual incident reports and the collection of visual materials, as well as an assessment of contributing factors such as tree species and canopy cover maps, infrastructure age and characteristics, and so on.

C.3.2 Other Winter Storms

For comparison to the December 2013 event, other ice storms were reviewed to determine if thresholds from previous research (Klaassen et al. 2003) were directly applicable to the City of Toronto and to also determine the severity of impacts from less severe and widespread storms. Klaassen et al. (2003) indicated that ice storms with as little as 15 mm of total ice accumulation have resulted in widespread power outages, mainly due to tree limb impacts, and while this agrees well with analyses from the December 2013 storm, other events should also be interrogated.

C.3.2.1 January 31st to February 4th, 2003: Complex Winter Event

The period between January 31st and February 4th, 2003 saw multiple types of precipitation and a variety of conditions impacting the Toronto Hydro distribution system, and resulted in over 50,000 customers being affected at various time by power outages (ITIS data). Some 160 incidents were reported in the ITIS database beginning on the evening of January 31st through to February 4th, including blown transformers and current limiting fuses, tracking problems, and some instances of galloping and tree contacts. On the night of February 3, 2003, "hundreds" of car accidents and numerous power outages were blamed on a combination of freezing rain and high winds, mainly across Scarborough and North York (Toronto Star, February 4, 2003). These impacts were the result of a complex weather event which involved two large scale low-pressure systems, several different types of precipitation, and significant associated temperature variations over the course of 5 days.

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[4] In meteorology, these are termed "meso-scale" weather phenomenon, which tend to occur on spatial scales smaller than distances between important surface observation stations, and on sub-daily (less than 24 hour) temporal scales.

A low pressure system which had originated in Alberta impacted southern Ontario on January 31st and February 1st, followed by a second low pressure system which had originally formed over Texas and Oklahoma, impacting Toronto on February 3rd and 4th. In addition to impacts to Toronto Hydro's system, power outages were also reported in Richmond Hill and Markham (Toronto Star Feb 4, 2003).

Impacts on February 1st were almost exclusively restricted to 27.6 kV equipment (except for one report), and, save for a few downed wired and tree contacts, were generally characterized generally consisted of tracking, electrical shorts and blown fuses associated with ice accretions. Beginning at around 10:30 am on February 1st through to the morning of February 3rd, several reports of electrical shorts and salt covering equipment were received, likely associated with attempts at deicing following the January 31st-February 1st storm. On February 3rd, freezing rain related reports began anew at ~5 PM and continued until 6 AM one February 4th. For this episode of severe weather, winds had been forecast to reach 70 km/h on February 3rd; maximum gusts would eventually be measured at 78 km/h (Pearson Airport) and 85 km/h at (Toronto Island Airport) the following day.

Conditions at Pearson Airport indicate that for the entire period between January 31st and February 4th the atmosphere was near or at saturation, with fog and haze being reported in conjunction with and between bouts of freezing rain, drizzle or light snow, however a total of only four hours of freezing rain were reported at Pearson Airport during that period. Temperatures crossed the 0°C boundary no less than *eight* times during this time period (**Figure C.7**).

The types of impacts, where descriptions were available, were quite different than those indicated for the December 2013 ice storm. Reports during the first portion of the event, mainly on February 1st, involved blown current limiting fuses and tracking problems. During the "break" in precipitation between February 1st and 3rd, 14 instances of *salt* related problems were addressed. Following this, a second round of precipitation, including the only reported freezing rain at Pearson Airport, combined with increasingly strong winds into February 4th, brought the first reports of galloping (mainly in Etobicoke) and only 4 reported instances of tree contacts, in addition to more blown fuses and pole top fires from icing related electrical shorts.

A *separate* storm over the Atlantic coast during the same time period, impacting the Maritimes on February 2nd and 3rd and producing 40-60 mm of ice accretion knocking out power to over 63,000 customers and causing other *very* significant damage, including roof collapses of barns and other storage buildings (EC 2003). By February 5th, 27,000 customers remained without power in New Brunswick (Toronto Star, Feb 5, 2003). The majority of repairs to the electrical system lasted for 5 days, and several locations had to be repaired twice or three times due to continued falling of ice laden trees, which was further exasperated by winds of ~75 km/h following the freezing rain (EC 2003). Massive ice accretions associated with this storm were at least partially due to the proximity of the storm to its source of moisture. Hence, while it produced similar wind speeds to the February 3rd and 4th low pressure system that affected southern Ontario, ice accretion amounts were *far* greater.

C.3.2.2 Case Study Specific Findings for January 31st-Febraury 4th

Galloping was indicated during the second storm, mainly in Toronto's west end, from what were likely a combination of ice accretions of on the order of 10 mm or less, but with winds gusting to the 70 to 80 km/h range. This is fairly close to the "15mm + 70 km/h" wind threshold indicated in previous work (CSA 2010), but may have been associated with lower ice accretion values but higher wind speeds. Additional cases would be needed to understand if galloping due to combined ice-wind loads occur in a range of wind speed and ice accretion combinations, but this case does indicate the potential for forecasting such problems when combined with monitoring of ice accretion.

Additional ice accretion, from either drizzle or light snow, coupled with several hours of reported fog or haze, is also highly likely for this event, but additional date related to this event is needed to diagnose actual accretion amounts and their causes. One should also consider that heavier precipitation may have occurred further east in North York and Scarborough, where the majority of ice accretion related impacts were reported. Indeed, several ITIS damage reports from those locations indicated ongoing snow and/or freezing rain for times when conditions at Pearson did not indicate *any* ongoing precipitation (e.g. two reports of snow in North York on the night of January 31st correspond with reports of "haze" at Toronto Pearson for the same time period). High wind and galloping conditions are likely better captured by records at Pearson Airport, since many of those incidents were reported much closer in Etobicoke.

When considering the types of impacts reported for this even, it is suggested that fog ice accretion may have slightly different characteristics than freezing rain ice accretion, which may result in slightly different impacts; i.e. when ice accretes due to fog and light drizzle in a humid environment, does it coat equipment differently than more rapidly accreting freezing rain? Did this lead to more localized problems associated with shorts and arching, in contrast to failures associated with direct physical impacts from ice loading and tree contacts? The role temperature fluctuations during and following periods of precipitation should also be investigated further. The degree of temperature variability for this event was much greater for this even when compared to the December 2013 ice storm, which again may have affected the type and degree of impacts (see **Table C.3**).

C.3.3 Large Scale Wind Storms

Large scale wind storms were identified through the Toronto Hydro Outage data for the 2000-2006 period. The maximum wind gusts reported during these storms were then compared to the number of outage events reported in the ITIS database and were also compared to the cause description, mainly identifying whether or not tree contacts were mentioned. The results of this comparison are described in **Table C.4** and illustrated in **Figure C.8**. Large scale, long duration wind events associated with low pressure systems were chosen instead of summer severe wind events associated with severe thunderstorms, since wind measurements at Pearson and Island airports were more likely to be representative of wind conditions at the damage sites for the large scale storms.

For the majority of events, a threshold wind speed of around 90 km/h emerges. A recent event on November 1, 2013, described in Toronto Hydro press releases but not well captured in ITIS, bears this out, in which 3,500 customers lost power during a wind storm which produce gusts up to 91 km/h at Pearson Airport.

It is notable that one of the most significant events, September 19, 2003 with 99 damage reports, also had the lowest reported gust at 72 km/h and is a pronounced outlier on the graph (bottom bar in **Figure C.8**), and the only other event which occurred in September shows the 2nd lowest wind speed value at 78 km/h.

To further investigate this wind speed relationship, the month of November 2005 was "back checked" to see how well a threshold of ~90 km/h was able to predict impacts to the Toronto Hydro system (**Table C.5** and **Figure C.9**). A total of 53 outage incidents were reported in ITIS for this month, with the largest number reported on November 6th and into the early morning hours of November 7th (35 reports). As indicated in **Table C.4**, these correspond with gusts of up to 89 km/h. Incidents were reported on 6 other days, with the second greatest number occurring on November 9th (9 reports). That day saw snow during the morning hours, followed by severe thunderstorm activity which resulted in one tornado in the City of Hamilton. Damage from thunderstorms is expected to be localized and therefore low wind speeds measured at Pearson airport are not surprising. The day with the third greatest number of reports also shows the second highest gust reported that month.

There are a number of potential reasons for this apparent seasonal difference between wind speed thresholds, most likely the effects of deciduous trees being still in full leaf, but, other considerations, such ground softness due temperatures remaining above freezing, must be considered given the very small sample size present here. However, data do appear indicate that threshold winds for damage increased from ~70 km/h during early fall up to ~90 km/h for late fall and winter windstorm events, and the causes listed for these impacts hint at a relationship to tree contacts.

We should mention that spring low pressure systems are also capable of producing high winds, but these do not seem to be as significant as fall season large scale wind storms. Spring severe wind storms also tend to have embedded thunderstorms, which act to further localize winds and complicate efforts to determine the representativeness of measurements. Examples of this event type include the April 20 to 21, 2000 and April 12, 2001 storms. March 9-10, 2002 is the only significant spring wind storm in the 2000-2006 period, but this event was also accompanied by severe thunderstorm activity which produced much more significant impacts in other parts of Ontario, including the loss of multiple Hydro One electrical transmission towers.

C.3.3.1 Superstorm Sandy: October 29-30, 2012

So-called "Superstorm" Sandy, responsible for major devastation in several major east coast cities in the United States, also produced impacts in Canada, including one fatality from windblown debris. Toronto Hydro estimated about 60,000 customers had lost power during the storm (T.H. Press Releases, Toronto Star 2012). Adjacent LDE Enersource reported approximately 6,000 customers lost power during the event, with 6 crews beginning restoration efforts at around 6PM on October 29th (Mississauga News 2012). Causes for these outages included the loss of three hydro poles. ORNGE air crews had also been grounded at 2 pm October 29th due to high winds (Toronto Star 2012).

Toronto Hydro had been initially criticized for not immediately declaring Level 3 status for this event and beginning repairs; however, the vice president of grid management indicated attempting repairs during the storm would have been futile and dangerous for repair crews (Toronto Star 2012). "There's nothing we could have done between 2 am and 6 am." Press releases issued as early as 6 PM on October 29th warned customers that repairs may be impossible during high winds.

A map depicting impacts and rainfall measurements for the event is provided in **Figure C.10**. Unfortunately, outage incident data appears to be incomplete for this time period (the event having occurred after 2006), and media reports for the city of Toronto lack specific damage and failure location descriptions. This is in sharp contrast to media reports from the City of Mississauga (Mississauga News 2012), the source of all media damage reports indicated in **Figure C.10**.

With the exception of one incident, wind damage reports from ITIS all appear in the southern half of the City of Toronto, and these also correspond very well with media reports of wind damage in Mississauga, as well as the difference in measured severity between Pearson (80 km/h max gust) and Toronto Island (91 km/h). There are simply too few available rain related damage reports to determine if important thresholds were reached for direct overland flooding related damage, and a comparison between Buttonville and Pearson to determine if antecedent rainfall played an important role appears to be negative. Both areas experienced similar amounts of antecedent rainfall on October 28th, followed by wind gusts of similar magnitudes on October 29th; however, only areas located southwest and southeast of Pearson reported any notable wind damage.

Toronto Hydro press releases, including those issued as early as 9:30 PM on October 29th, before the peak of the storm, in indicated trees and tree limb contact with overhead wires as the main cause of the outages (T.H. 2012). The October 30th 10:39 PM press release specifically indicated, "Toronto Hydro estimates that more than 85 per cent of outages were caused by tree contacts with power line[s]" Further indicating that repairs are expected to exceed $1 million and that other jurisdictions, which have far less tree cover, were not expected to be as heavily impacted. On the evening of October 30th, the worst affected area was roughly bounded by "Talwood Drive (north), Eglinton Ave E (south), Bayview Ave (west) and Don Mills Rd (east)"

The preponderance of tree and tree related damage in the southern portions of Toronto and Peel, coupled with the transition from wind gust regimes from 80 km/h to 90 km/h, further supports the findings from the analysis of large scale wind storms indicating wind speed thresholds of 90 km/h, again likely related to tree contacts. Budget and time limitations prevent further analysis of this event (e.g. search for impacts in Durham region) for the time being, but further research is strongly indicated.

C.4 Severe Summer Thunderstorm Events

C.4.1 July 8, 2013 Extreme Rainfall Event

"Little India resident Kurt Krausewipz, said the 'thick heavy sheets of rain,' reminded him of monsoon season in Southeast Asia." (Toronto Star, July 9, 2013)

The flash flood event on July 8th, 2013 was responsible for the largest 24 hour rainfall amount ever reported at Pearson Airport. The event was notable for a number of important impacts, including the stranding hundreds of GO transit commuters for 5 hours on a flooded train in the Don Valley (Toronto

Star, July 9, 2013), as well as an eventual tally of nearly $1 billion in insured damages (CBC.ca 2014), mainly resulting from basement flooding. It also resulted in a significant power outage event for Toronto Hydro, with approximately 300,000 customers losing power for several hours[5] (Toronto Hydro Press Release, July 9, 2013). The outage event was mainly triggered by the failure of critical infrastructure located below grade[6] at two transformer stations linking Toronto's distribution system with Ontario's electrical transmission system.

To understand the magnitude of the event, and to assist with developing a threshold for this type of failure, maps depicting rainfall amounts across the city (Cole Engineering Group, 2013) were compared with media reports of damage, as well as the locations of the two transmission stations which suffered failures during the event (Hydro One, 2014). See **Figure C.11** for station locations relative to rainfall accumulation amounts.

The extreme rainfall event began around 4 PM and produced eventual failures at Manby and Richview transformer stations, with Hydro One declaring a "Level 2 Transmission Emergency" (Hydro One 2014). Both are located within and near the area of greatest rainfall accumulations recorded for the event, located roughly along and on either side of the Etobicoke-Mississauga border (Cole Engineering Group, 2013). A rainfall total of 126 mm was reported at Pearson International Airport, with a maximum 1 hour total of 74 mm (EC 2014); however, this was roughly within the western edge of what municipal rain gauge networks indicate as a "bull's-eye" centered slightly E of Pearson International, which contained accumulations of over *130 mm* of rain (Cole Engineering Group, 2013). Richview TS is located in the *immediate center* of this area of extreme precipitation. Manby TS is located several kilometers to the south and was subject to far less rainfall in its immediate vicinity, located nearly on and just north of the 80 mm rainfall contour. It is not clear how much additional flooding at Manby TS was the result of runoff from areas further north, or if the design and characteristics of Manby TS may have made it more vulnerable to flooding than other stations. Hydro One's system officially returned to "normal" status at 2:44 PM July 15th (Hydro One 2014).

"Level 2 remained in effect until 5:34 p.m. on July 12th as Hydro One worked to reinforce the system with restored transmission connections between Richview TS and its remote terminal stations: Trafalgar TS, Cherrywood TS, Parkway TS and Claireville TS. This provided redundant supplies and vastly improved network security." (Hydro One, 2014)

It is notable that stations located near a secondary maximum over downtown Toronto (particularly Leaside TS), did not suffer the same impacts as Richview and Manby. Rainfall in the core of the downtown maximum approaching 100 mm. Toronto's climate station at the U of T campus reported 96.8 mm of rain (EC 2014), but Leaside TS is located approximately 3-4 km to the NW of the core of this

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[5] In contrast to the Dec 2013 ice storm, however, the nature of the failures allowed for ~90% restoration for distribution customers by the early hours of the following morning (TH Press Release, July 9, 2013).

[6] Interviews by RSI with practitioners at the OPA for the "sister" transmission case study indicated that placement of critical infrastructure in below grade locations may have also played a critical role in the failures experienced in this case.

much smaller maximum subject to an estimated 65-70 mm rainfall, and was also not “down-stream” from another maximum as was the case for Manby TS.

Rainfall data from Pearson International also indicate possible antecedent rainfall conditions, since 26.6 mm of rain were recorded on July 7th, the day prior to the event, and a total of 31.4 mm of rain was recorded in the full week prior to the rainfall event (EC 2014). Similarly, Toronto’s downtown climate station reported 38.1 mm of rainfall on July 7th and a total of 48 mm during the week preceding the July 8th flood.

“Since June 1, downtown has seen 165 mm of rain, about double the average of 87 mm.” (Toronto Star July 9, 2013)

As with the Superstorm Sandy case, outage data appeared to also be lacking in the ITIS data, with only one listing indicated for this event. However, the clear cause in this case was the direct impact to transmission infrastructure, reducing the need for similar analyses conducted for other cases in which outage causes were more local and directly related to physical impacts to the distribution system.

C.4.1.1 Case Specific Findings July 8th Flood

Rainfall in excess of 100 mm in less than 24 hours, and indeed within the span of only a few hours, appears to have been required to cause the types of failures experienced at the two western Toronto stations. Antecedent rainfall may have also played a role in the flooding, generating more runoff than would have otherwise occurred. Topography and associated runoff patterns may have also played a role, particularly for Manby TS, but conclusive evidence of this would require further investigation.

This may also be a case of extreme rainfall rates under the “sub-daily” category, given that both this case and August 19, 2005 saw the majority of rainfall occur within a few hours, with a majority of the total 24 hour rainfall occurring within approximately *one* (1) hour. Extreme rainfall rates should be directly correlated with runoff efficiency and design requirements (e.g. pumping rates for mitigation, flash flood peaks, etc.) and may be important in determining how such events generate severe impacts to these systems.

While the main infrastructure that failed was indeed owned by Hydro One, these findings have direct implications of great importance to Toronto Hydro Infrastructure. Toronto Hydro was still directly and severely impacted by the failure of 3rd party infrastructure. The PIEVC process includes 3rd party infrastructure among the needed elements for review and consideration, and this is particularly relevant for the highly interconnected electrical grid as a whole. While this was not the case in this particular event, similar infrastructure owned by Toronto Hydro may be susceptible to extreme rainfall conditions. These locations and infrastructure elements should be explicitly identified and evaluated for their vulnerability.

C.4.2 August 19, 2005 Finch Washout Event

A large “supercell” thunderstorm produced significant impacts across a swath of south-central Ontario on August 19, 2005. Perhaps the most well-known and publicized impacts from the event consisted of the complete washout of a section of Finch Avenue at Black Creek in North York. In addition to this, however, there were numerous reports of basement flooding in Toronto and York region, several vehicles being swept off of roads or submerged, in addition to several thousand homes in Toronto suffering power outages, mainly in Etobicoke and Scarborough areas (Toronto Star, August 20th, 2005). The specific causes for these outages were not provided by media reports, however ITIS incident reports, coupled with the location of reported damage, indicate that outages were mainly related to flooding. Preceding the impacts in the GTA, the supercell storm produced two large, F2 tornadoes west of the city in the Listowel and Fergus areas, severely impacting farming and cottage communities.

A map of reported impacts is provided in **Figure C.12**, combining ITIS and media damage reports with meteorological measurements for comparison. A fairly clear pattern emerges in which a corridor of extreme rainfall with embedded amounts in excess of 100 mm corresponds quite well with the majority of extreme rainfall related outage incidents, indicated by red and orange circles superimposed with an "X" in a band extending from central North York ESE to Scarborough. Extreme rainfall amounts to the immediate north of Toronto were also associated with significant basement flooding in York region. A second more isolated patch of extreme rainfall may be indicated in north Etobicoke, but could also be illusory due to the suspect reading (only 24.7 mm) located north of the Finch Washout.

Interestingly enough, tree contact and wind related damage reports are generally located south of the corridor of extreme precipitation; this is consistent with the storm type. While impacting Toronto and the GTA, the storm produced a swath flooding rainfall and large hail under as a core of heavy precipitation tracked across the city, while winds gusting to ~70 km/h or more were present *south* of this core and were responsible for several minor tree contact related damage reports[7]. A comparison between wind measurements at different locations, however, could not be conducted, as wind gust data are not available for this date for Toronto's Island airport.

C.5 Extreme Heat Days

While it is generally common knowledge that during hot and humid days during the summer, air temperatures are much cooler along the shores of Lake Ontario than they are in other parts of the city, the potential impact this temperature difference may have on electrical system response is not often considered.

Table C.6 provides a comparison between three stations to determine temperature differences across the City of Toronto on days in which high heat impacts on the distribution system were indicated (see **Table C.2** for greater details). These stations are located on or very near the western, southern and northern boundaries of the City of Toronto and provide an excellent measure of the temperature differences experienced across the city. Temperature differences of between 2.6 and 5.7 degrees are evident, while the locations of impacts strongly indicate a preference for impacts to infrastructure in Etobicoke. The number of incident reports appear to be correlated to the maximum temperature, although sample size is extremely small. The average temperature difference between Pearson Airport

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[7] Had the storm produced a tornado while over the city, it would have been located at the southern edge of the heavy precipitation core. Luckily, the storm changed characteristics when approaching the GTA and appears to have been no longer tornadic when impacting the area.

and Toronto Island Airport is 4.1 degrees for the four high heat days, and the difference between North York Climate Station and Toronto Island is slightly less at 3.1 degrees.

Figure C. 13 shows an example of a high heat day (July 16, 2006) in which impacts began to be reported in North York at two different transformer stations. Interestingly enough, two of the four reports are listed as “Adverse Weather/Tree Contacts”, and we are unsure of the nature of these reported causes. Either they have been mistakenly coded, or tree contacts may have occurred due to line sag, but details on the specific impact characteristics are lacking. The small number of reports indicated in North York for this date and the inter-comparison in **Table C.6**, coupled with results from the literature review and discussions with practitioners, provide additional evidence that negative impacts to the distribution system begin to appear as temperatures approach ~35°C.

This case, however, provides an excellent example of the temperature gradient often present across the City of Toronto during extreme heat days, with slightly higher temperatures occurring further from the lake. During the summer, the temperature difference between land and lake often result in the production of a lake breeze, in which cooler, heavier air over the lake flows inland, the leading edge of that air often acting as a miniature cold front. This can result in notable temperature gradients across the city, and can also trigger and/or enhance thunderstorm activity at the boundary between lake air and air further inland.

Although time and resources did not allow for more detailed assessment, a greater number of days in which extreme heat impacted the Toronto Hydro distribution system should be further investigated to help refine this threshold further. Further analysis is also needed to ensure that the impacts of other air mass boundaries (i.e. large scale fronts) are not skewing the results presented here, as similar temperature gradients can be produced through other mechanisms unrelated to the effects of the lake.

C.6 Final Conclusions

In summary, the forensic analyses resulted in the following conclusions:

- Although data sufficiency and time allotted to the project prevented the thorough investigation of many of the events identified through this forensic analysis, several avenues of future research were identified which could lead directly to improved operational maintenance and management measures, including improved forecasting of climatic impacts to assist in anticipation and preparation for significant events.
- In some cases, it was clear that Toronto Hydro operations and maintenance crews were making effective use of forecasts to help plan and optimize repair and response, such as allowing severe weather conditions to pass before full repair operations were initiated.
- In most cases, and particularly for those in which localized differences in impact severity were evident, further analysis was stymied by a lack of observational data. Even with the inclusion of additional observational data provided by TRCA (2014), spatial gaps in observations prevented the assessment and diagnosis of conditions in certain locations (e.g. December, 2013 ice storm

damage in Scarborough lacking ice accretion or temperature measures; August 19, 2005 severe thunderstorm wind speed measurements in southern portions of the city).

- The majority of power outage events identified in the 2000-2006 period were extended events lasting up to 48 hours, representing the need for sustained operational response, but the characteristics of these events differed depending on season:
  - Extended warm season events consisted of 2 or more acute weather events in quick succession, and were a combination of related hazards producing impacts (e.g. extreme heat followed by thunderstorm activity)
  - Cool season and shoulder season events tended to last several hours; when storms occurred in succession, they tended to be separated by periods of one or more days
  - The years with the greatest reported impacts to the distribution system were characterized by multiple moderate to major outage events occurring in different seasons (e.g. significant severe thunderstorm event during the summer followed by one or more wind storms during the fall season)
- Thresholds determined for wind speed and ice storm damage agree well with previous work and research, and these also appear to be *directly* related to tree contact related impacts rather than direct climatic loading of infrastructure through wind or ice accretion.
  - The 70 km/h threshold for wind gusts, originally provided by Toronto Hydro staff during Phase I, appears to be correlated with tree damage, particularly during the warm portions of the year when deciduous trees are in full leaf, resulting in secondary impacts to the distribution system; further research is needed to confirm this relationship
  - The 90 km/h threshold appears to be both related to the baseline climatic loading used in design of civil infrastructure components (see CSA 2010) as well as tree damage after deciduous trees have shed their leaves
  - The lower bound of 15 mm for freezing rain totals resulting in tree contacts with overhead systems agree well with the findings from Klaassen et al. (2003)
  - Freezing rain totals of less than 15 mm, however, may cause impacts when combined with high humidity environments near the 0°C boundary. This can specifically result in flashovers and other related impacts. While not as severe as direct damage to overhead lines and other equipment, these types of impacts can be numerous, widespread, and localized, presenting particular challenges for restoration efforts
- Overall, larger metropolitan LDCs appear to be more vulnerable to climatic events than smaller LDCs, particularly when considering overall restoration times; this is likely due a culmination of factors, not the least of which include the state and age of equipment, difficulty of access for system repair in an urban environment, and the relative proportion of staff available with respect to total number of customers and the size of a geographical area of responsibility.
- Certain regions within the city appear to be more susceptible to weather related power outages; potential regional differences in vulnerability should be investigated further. It is not clear at this time if these vulnerabilities are due to aging infrastructure, proximity to aged canopies, difficult to access infrastructure (e.g. back-lots) or some other combination of factors.

- There were several cases in which events tended to follow one-another in series, with either the restoration following a major event being hampered by subsequent smaller events, or several moderate events resulting in prolonged, multi-day outage cases where new damage occurred immediately following recovery from previous events
- Extreme rainfall impacts are worst with warm season severe thunderstorms. These were characterized by highly localized events impacting only a portion of the City, generating rainfall accumulations of over 100 mm, the majority of which (>50%) falling on during a period of *one hour*. Rainfall impacts with longer the longer duration, larger scale events investigated here (e.g. "Superstorm Sandy") appeared to be minor.
- Changes in tree health conditions such as disease and pests may also be playing a role in increasing sensitivity to damage, as suggested by analyses of the December 2013 ice storm. These represent very complex interactions, since the extent of certain disease and pests will also be affected by changing climate regimes, and their interaction with the structural integrity of trees and limbs is still unknown.
- Even for winter events, which are ostensibly much less localized in nature than warm season storms, localized differences in infrastructure impacts were evident, and without additional data, the causes for these disparities were not entirely clear. In one case (December 21-22, 2013) a small scale weather feature was explicitly identified as having very likely been a major contributor to the case overall, and similar findings are expected if similarly in-depth analyses are conducted of other high impact winter storms.
- Differences in impacts due to storm structure and other localized meteorological factors were evident in some cases (e.g. separation of precipitation and wind related impacts Aug 19, 2005). While these are to be expected, they may also assist in response to events when combined with remote sensing data, such that response crews may be better informed as to the type of impacts they may encounter following a severe storm.
- Events were not only characterized by impacts to the distribution system, but tended to consist of multiple, often severe impacts to other buildings and infrastructure, including transportation, and communication infrastructure. These impacts compounded effects on the distribution system by further complicating operational response.
- Smaller events which barely generated more than 20 damage reports, such as July 1, 2001 (lightning and rainfall) or April 28, 2002 (high winds), should be studied to understand where the lower damage thresholds may lie and/or which areas within the city or infrastructure types/categories are the *most* vulnerable
- The presence of Lake Ontario directly impacts the behaviour of certain weather hazards, generating differences in risk across the city; it generally moderates temperatures, warming areas adjacent to the lake during the cool season and cooling areas near the lake during the summer. This effect either mitigates or exacerbates the severity of hazards depending on the type of hazard (e.g. areas downtown are kept cooler during extreme heat days, but the leading edge of the lake breeze also plays a role in enhancing severe thunderstorm hazards for other portions of the city).

- The interconnectivity of Ontario's electrical grid is vital to understanding the potential impacts from atmospheric hazards; coordination between transmission providers and LDCs in risk assessment analyses may be *pivotal* in understanding and addressing these risks.

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Table C.1: Events subject to detailed investigation.

Date(s)	Event Hazard Type(s)
January 31st to February 4th, 2003	Multi-day ice accretion event; complex interactions
August 19, 2005	Flash flooding; lightning, some winds (tree contacts)
July 16, 2006	Extreme Heat; threshold/borderline event
October 29-30, 2012	Superstorm Sandy; winds, possible rainfall impacts
July 8, 2013	Flash Flooding; failure of 3rd party underground infrastructure
December 21-22, 2013	Ice Storm; mainly tree contacts

Table C.2: Toronto Hydro Events Outage Events 2000-2006 with *20 or more* incident reports.

Medium to High Impact Events T.H. Failure Database	Event Type	Number of Reports
February 23 to 25, 2000	rain and snow	**49**
February 3 to 4, 2000	freezing rain	**37**
February 16, 2000	snow and freezing rain	**72**
4/20/2000 and 4/21/2000	high winds and rainfall	**42**
May 12 to 13, 2000	wind, rain and lightning	**157**
6/14/2000 and 6/15/2000	lightning and "adverse weather"	**58**
14-Jul-00	lightning	**121**
7/17/2000 and 7/18/2000	lightning, some high winds, extreme heat	**88**
5-Jan-01	snow	**28**
12-Apr-01	high winds	**33**
1-Jul-01	rain and high wind	**21**
4-Jul-01	rain, lightning, and wind	**21**
7/22/2001 and 7/23/2001 and 7/24/2001	lightning	**53**
8/7/2001 to 8/9/2001	heat and humidity	**72**
25-Oct-01	high winds	**20**
1-Feb-02	high winds	**29**
March 9 to 10, 2002	"adverse weather"	**78**
28-Apr-02	high winds, rain	**21**
7/21/2002 to 7/22/2002	lightning, some heat and humidity	**107**
9/20/2002 to 9/21/2002	rain and lightning	**23**
1/31/2003 to 2/1/2003	snow and freezing rain	**155**
2/3/2003 to 2/4/2003	freezing rain	**71**
5/5/2003 and May 6, 2003	lightning	**45**
8/21/2003 and 8/22/2003	lightning, high winds and rain	**58**

19-Sep-03	high winds	99
10/15/2003 and 10/16/2003	high winds	81
11/12/2003 and 11/13/2003	high Winds	80
4-Jul-04	lightning, rain	43
23-Dec-04	Freezing rain	27
2/6/2005 and 02/07/2005	fog	25
6/13/2005 and 6/14/2005	lightning, some "tree contacts"	42
28-Jun-05	lightning	30
4-Jul-05	lightning, some wind and rain	68
July 11 to 12, 2005	heat and humidity	39
8/19/2005 and 8/20/2005	extreme rainfall, high winds and lightning; DETAILED ANALYSIS	162
29-Sep-05	high winds	42
6 to 7-Nov-05	high winds	35
2/17/2006 and 2/16/2006	high winds	49
31-May-06	lightning	24
6/28/2006 and 6/29/2006	lightning, rain extremes	88
10-Jul-06	rain, lightning	24
7/17/2006 & 7/18/2006	lightning, heat and humidity, some wind	66
8-Sep-06	rain, lightning	24
10/4/2006 and 10/3/2006	lightning and high winds	30
29-Oct-06	high winds	28

Table C.3: Comparison of ice accretion events with reported impacts.

Dates	Estimated Total Ice Accretion	Total # Hours **Freezing Rain** and Drizzle	Impacts
January 31-February 4, 2003	Est. ~10-12 mm (difficult given complex temperature regime and multiple	**Pearson: 4 hours (Feb 3rd);** no freezing drizzle reported, but snow, drizzle, fog and haze reported at various times	Most damage from shorted and blown fuses, tracking, few downed lines, galloping during high winds following 2nd period of precipitation; high humidity and multiple

	precipitation types)		temperature changes about 0°C
December 20-22, 2013	Est. <15 mm Downtown Toronto to 25-35 mm York and Durham Regions	**Pearson: 4, 16 and 6**, and 2, 5 and 10; **Buttonville: 8, 13 and 8**,and 1, 5 and 10; Total hours for December 20th, 21st, and 22nd, respectively	Mainly due to tree impacts, greater periods of temperatures above 0C and liquid precipitation for locations closer to downtown Toronto, significantly reducing ice accretion totals for full 3 day period

Table C.4: Comparison of highest wind gusts with large scale outage events.

Date	**Peak Measured Gusts (km/h)**	**Cause Description**[8]
25-Oct-01	Pearson: 91; Toronto Island: 82	Tree contacts 8/20
19-Sep-03	Pearson: 72; Toronto Island: 80	Tree contacts 32/99; other causes included “driving rain”, “auto reclose” of breaker due to high winds
15 to 16-Oct-03	Pearson: 91; Toronto Island: 89	Tree contacts 30/81; remainder mainly “high wind/adverse weather”, one report of “fuse fell open in high wind”
12 to 13-Nov-03	Pearson: 93; Toronto Island: 96	Tree contacts 16/64; remainder simply indicated as “high wind/adverse weather”, some lightning
29-Sep-05	Pearson: 78	Tree contacts 28/42, rest related to high winds, including broken insulator
6 to 7-Nov-05	Pearson: 89	Tree contacts 13/35
16 to 17-Feb-06	Pearson: 91	Tree contact: 8/13 (16th) & 12/34 (17th); also some freezing rain reported on both dates, remaining[9] were generally listed as high winds, incl. one broken insulator
29-Oct-06	Pearson: 96	Tree contact: 12/28 reports
1-Nov-13	Pearson: 91	Tree contacts: 3/7 reports

Table C.5: Comparison of *all* impact reports for November 2005 to maximum gust speed.

Date	Gust Speed (Pearson Airport)	**Number of Reports**; Notes
Nov 6th	89	**35**; 2 early morning Nov 7th, considered same event
Nov 9th	59	**9**; same day F1 Tornado, Hamilton, ON; morn report include

[8] Tree contacts were counted both when coded as cause, as well as cases where cause was coded as “adverse weather” but description of impacts indicated tree contacts were responsible.

[9] One report of a “temperature extreme” causing a failure at -3°C ambient temperatures appears to be a coding error.

		snow, thunderstorms mid-day and evening, wind caused limbs on wires 3 reports, lightning related outages 3 others
Nov 11th	35	**1**; rain indicated as cause
Nov 16th	83	**4**; three high wind reports, one “no cause”, “switch fell open”
Nov 17th	59	**1**; large tree on line, rain indicated
Nov 24th	78	**2**; winds indicated as cause, possible duplicate report of one incident
Nov 25th	48	**1**; conditions indicated as “clear” no specific cause given

Table C.6: Comparison of maximum temperatures (°C) for high and extreme heat days.

Date	**Impacts (# heat related reports)**	**Pearson Airport**	**Toronto Island Airport**	**North York Climate Station**
July 17, 2000	Minor; only 2 in Etobicoke	28.6	24.4	27.0
Aug 8, 2001	33 total; 18 in Scarborough, 10 Etobicoke	37.9	34.7	37.5
July 11, 2005	19 total; 10 Etobicoke, 7 North York	35.5	29.8	34.0
July 12, 2005	18 total; 7 Etobicoke, 7 North York	34.7	31.4	34.5

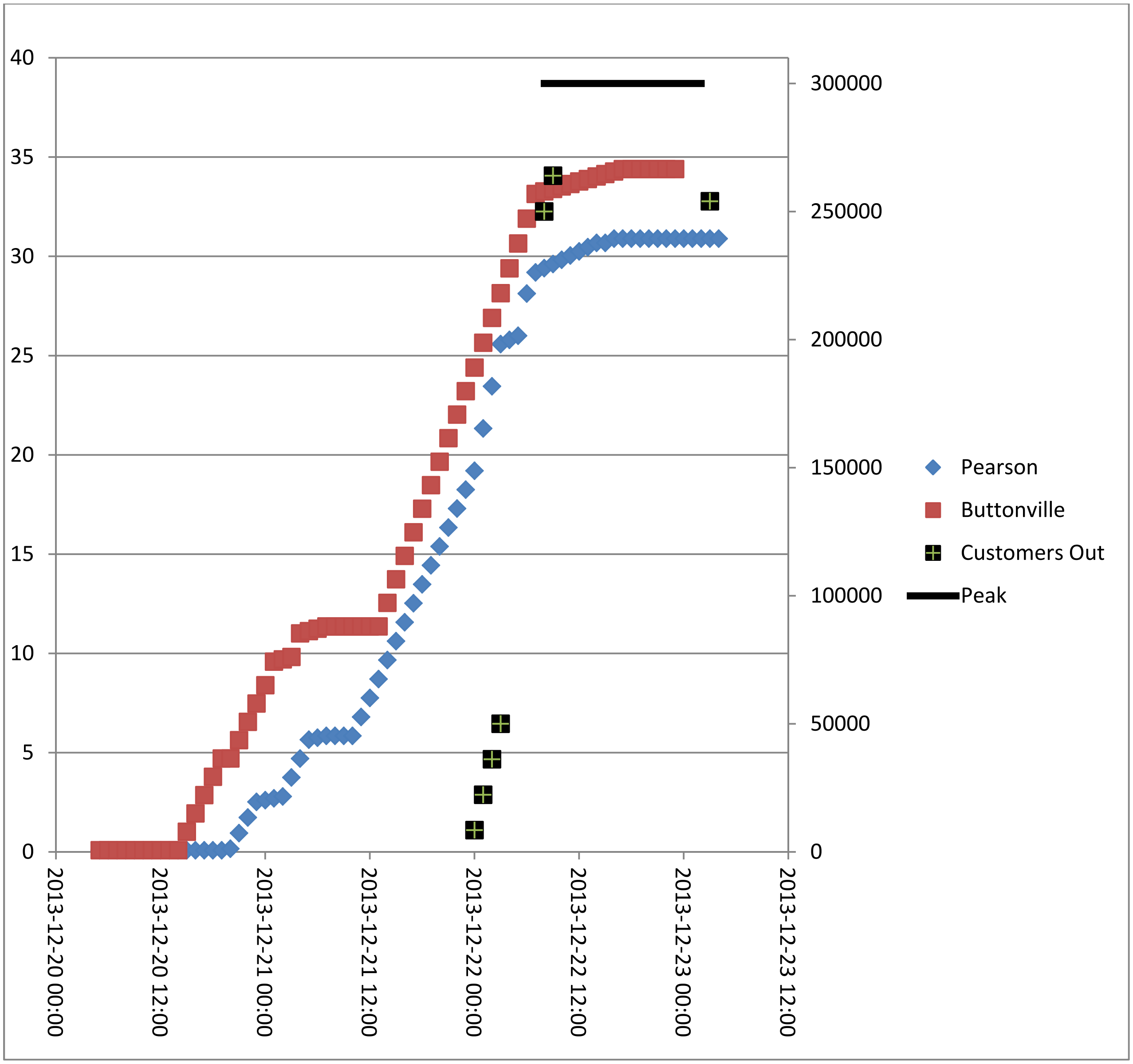

Figure C.1: Estimated ice accretion rates using observations at Pearson and Buttonville Airports. Peak outages (300,000 customers) is represented a long black bar since the exact time period in which this number of customers were without electrical service was not given and indeed may not be known.

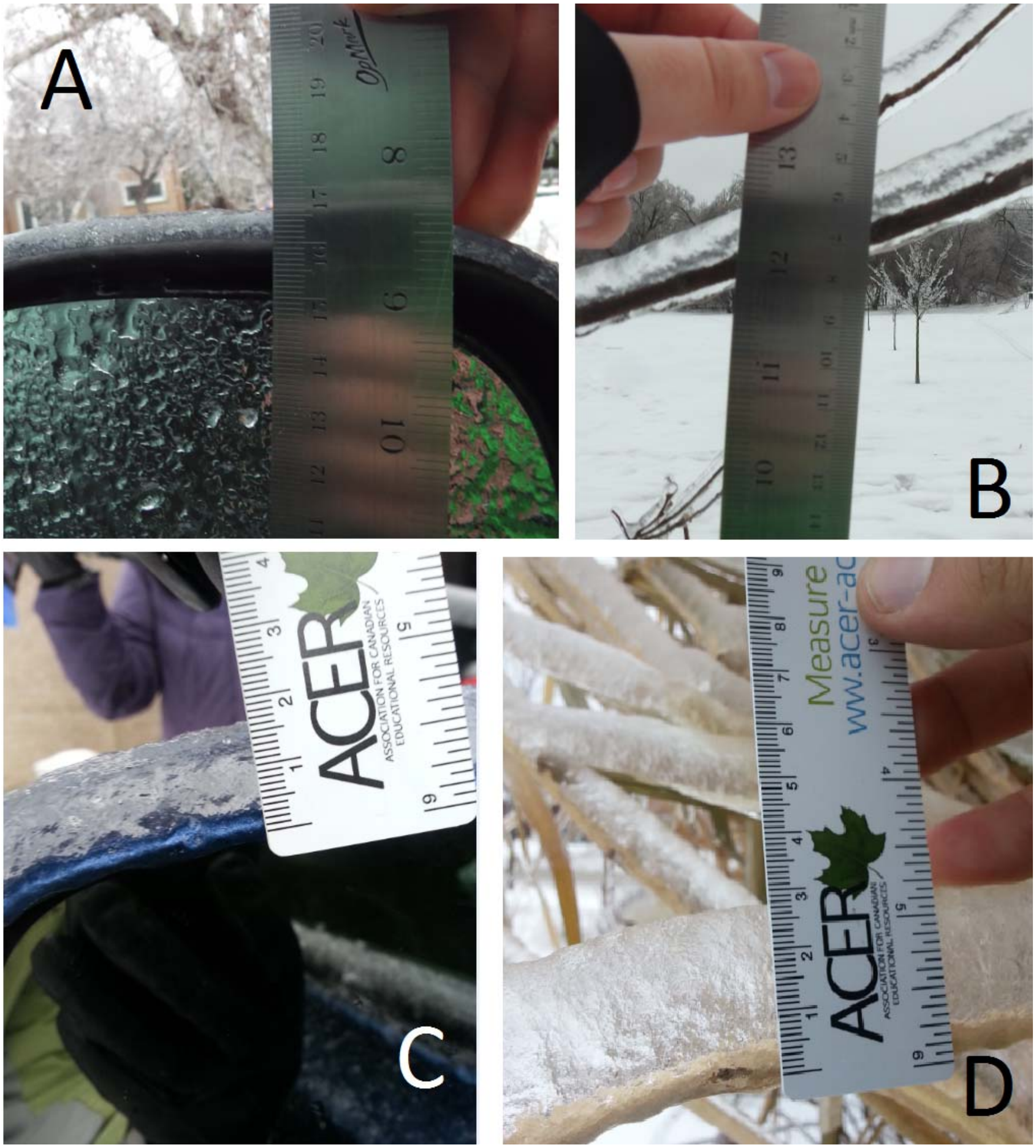

Figure C.2: Ice accretion measurements on similar objects are compared between locations in central Etobicoke (A and B), located ~5 km SE of Pearson airport, and Richmond Hill (C and D), ~9 km NW Buttonville Airport. Ice accretions on car side mirrors are measured at 6 and 15 mm and for branches of similar diameter at 10 and 23 mm, for Etobicoke and Richmond Hill locations, respectively. While measurements are not exactly equivalent in terms of exposure and accretion surface and shape characteristics, they do provide evidence that ice accretion amounts were appreciably higher for municipalities north of the City of Toronto in comparison to locations near Pearson Airport. Photos by RSI team members H. Auld (Thornhill) and S. Eng (Etobicoke).

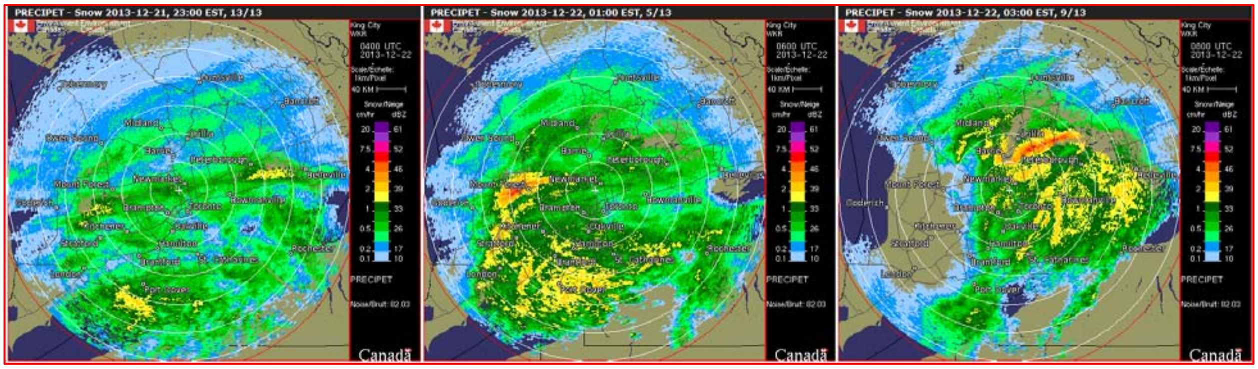

Figure C.3: King City radar imagery; panel times (left to right)correspond to 11 PM December 21st, 1 AM December 22nd and 3 AM, December 22nd, 2013. A small scale meteorological feature appears to have been responsible for an area of particularly heavy precipitation which tracked across the GTA in early morning hours, corresponding with the highest ice accretion rate estimates for the entire event.

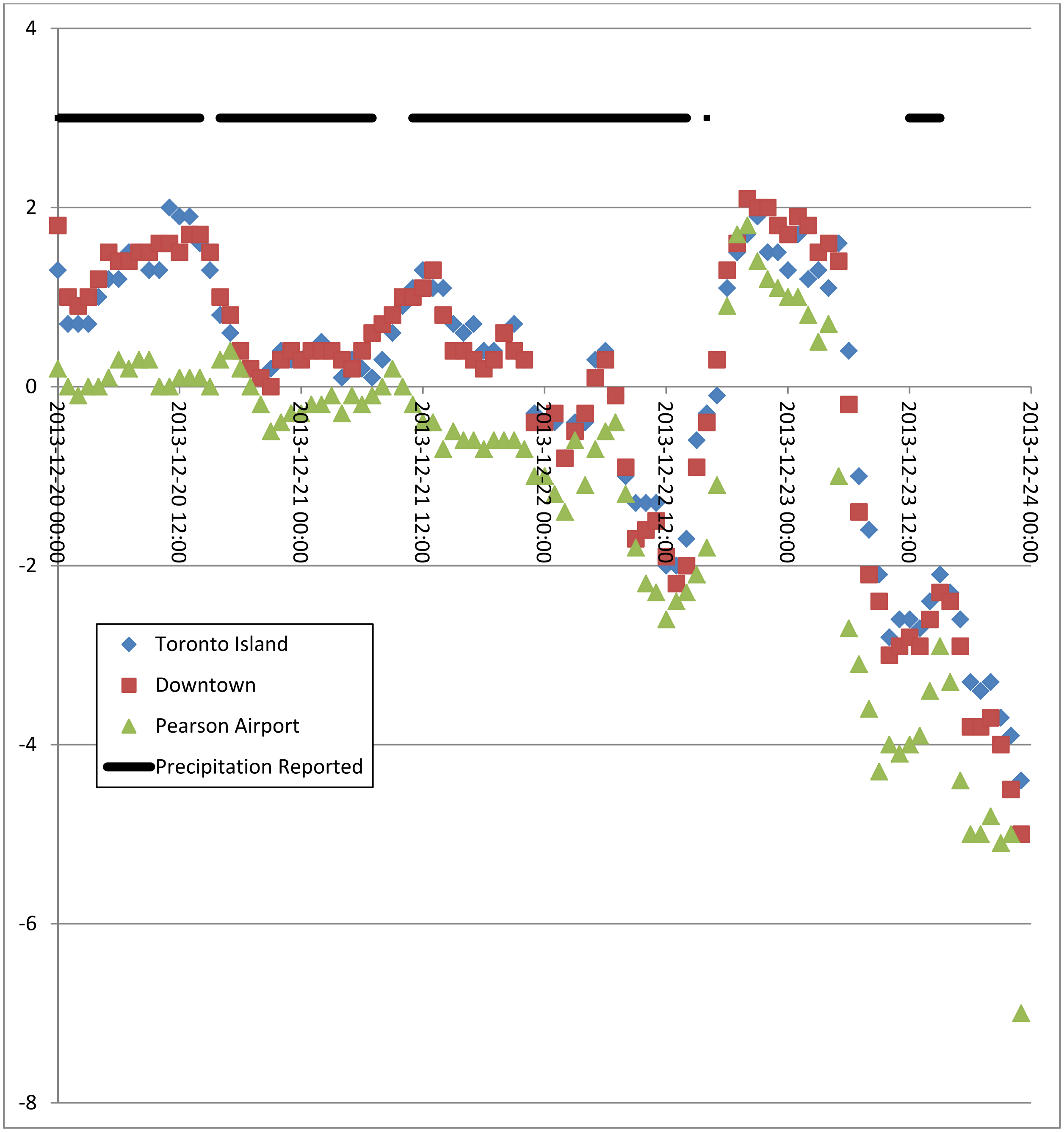

Figure C.4: Comparison of hourly temperatures between Pearson International Airport and stations located in downtown, accompanied by hours with reported precipitation. It is likely that precipitation occuring before 11 PM on December 21st did not contribute to any important ice accretion, but still resulted in significant impacts to many neighbourhoods in and around the downtown core.

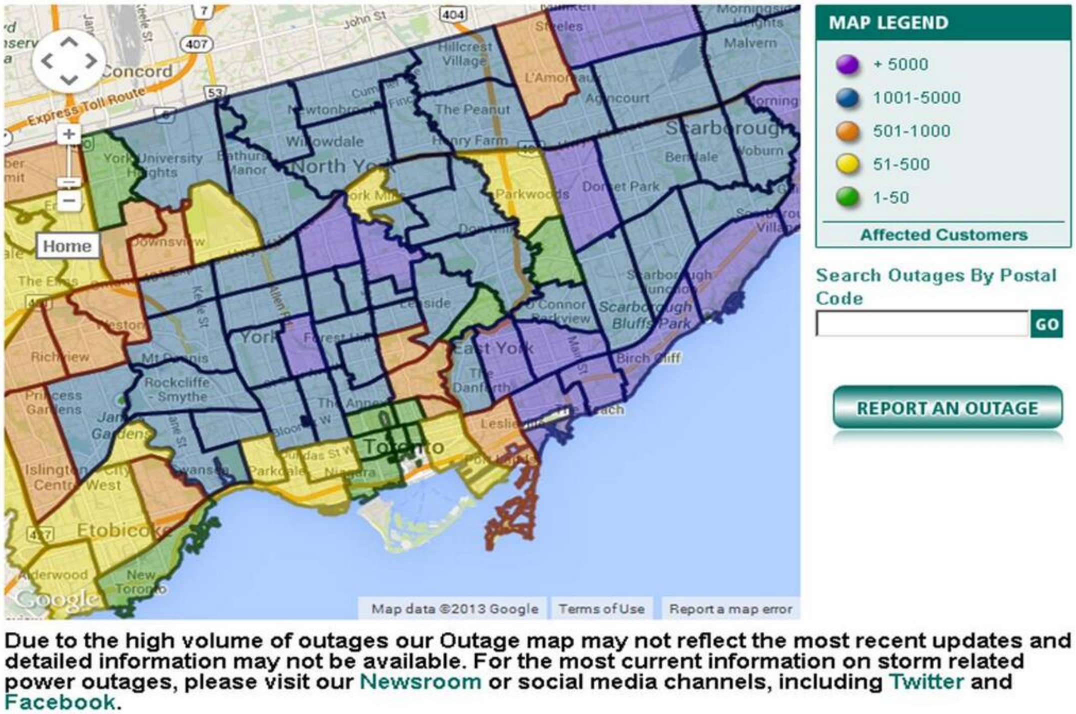

Figure C.5: Toronto Hydro outages map valid for 11 AM December 23rd. Note clear boundaries to north of Bloor and east of Woodbine/Don Valley. Unfortunately, both detailed impacts data and meteorological observations prevent better diagnoses of causes for these differences in system response to the event for areas like East York and Scarborough. Image retreived 11:50 AM December 23rd, 2013.

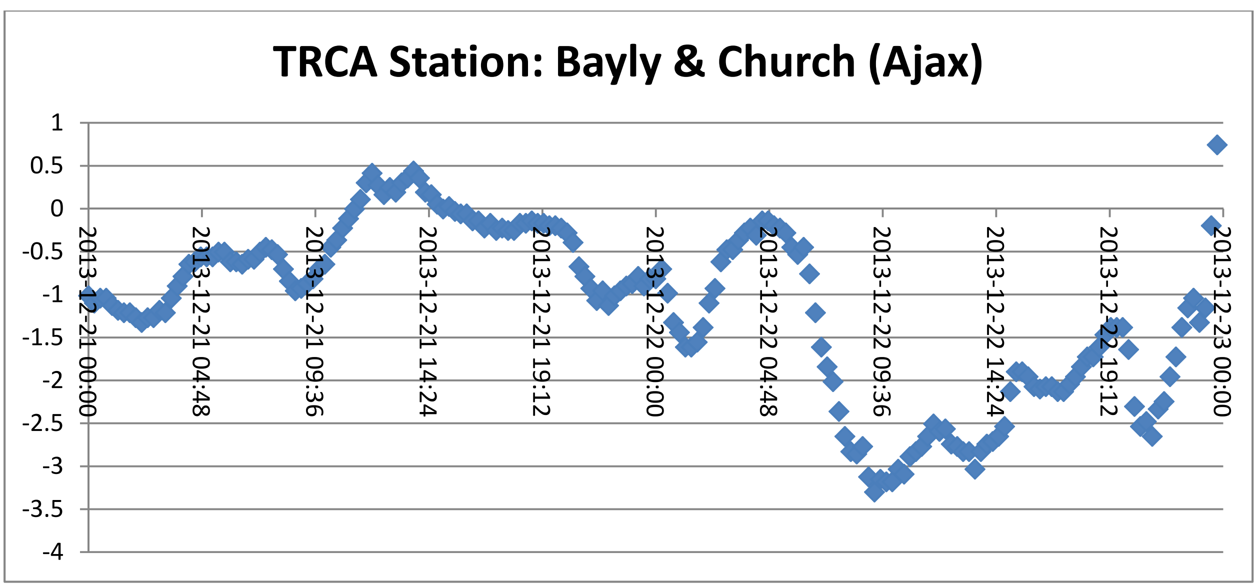

Figure C.6: Temperature Data from Bayly and Church in Ajax. When considered in conjunction with temperature and precipitation measurements from Oshawa Airport, these temerpatures indicate likelyhood that the majority of precipitation experienced between December 21st and December 23rd was in the form of freezing rain, suggesting ice accretions in Ajax were likely similar to other portions of Durham Region. Data courtesy of Toronto Region Conservation Authority.

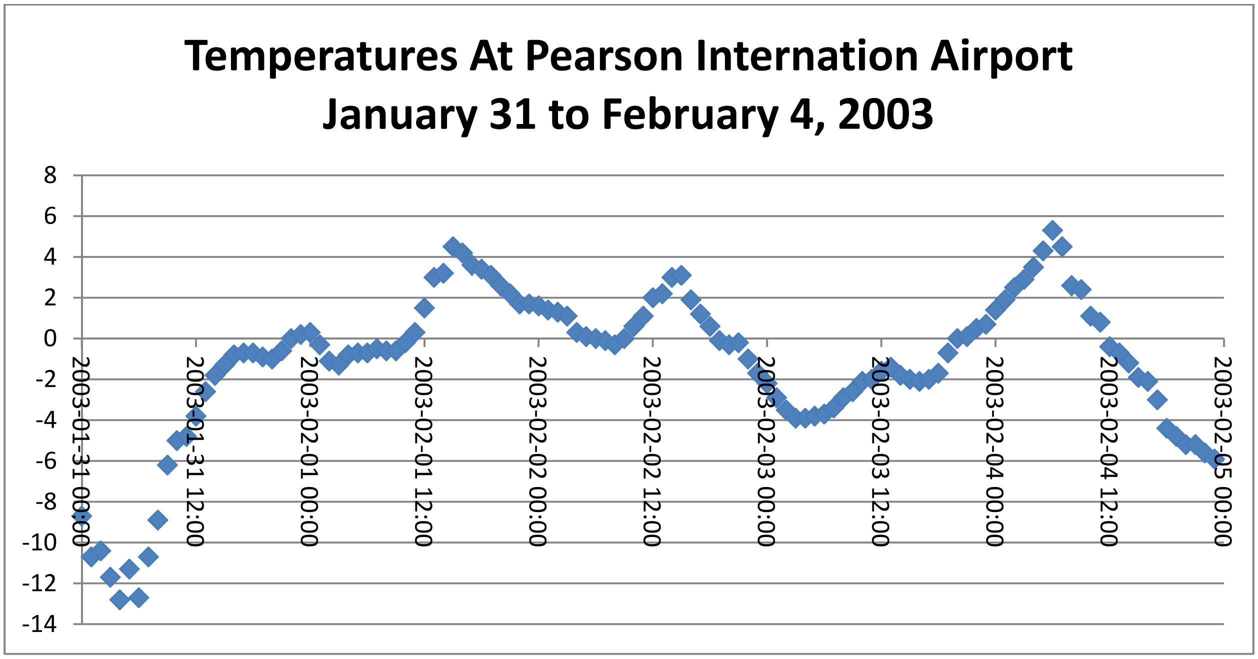

Figure C.7: Hourly temperatures at Pearson Airport between January 31st and Febraury 4th, 2003, corresponding with a complex winter event that produced a total of 160 incident reports as well as outages for over 50,000 Toronto Hydro customers. Temperatures "crossed" the 0°C line no less than 8 times during the 5 day period of unsettled weather.

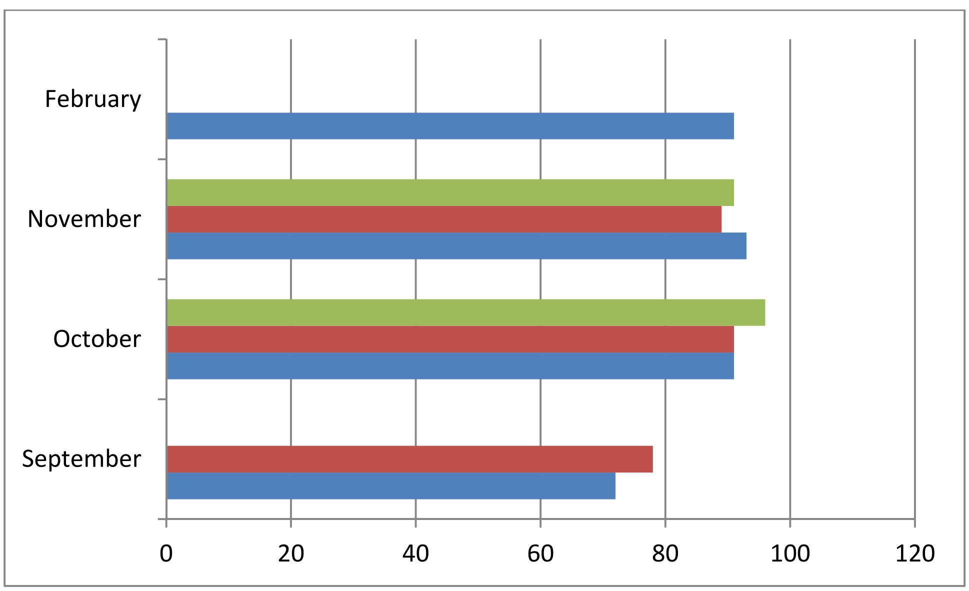

Figure C.8: Max gusts for outage events plotted by month indicate a potential relationship which deserves further study.

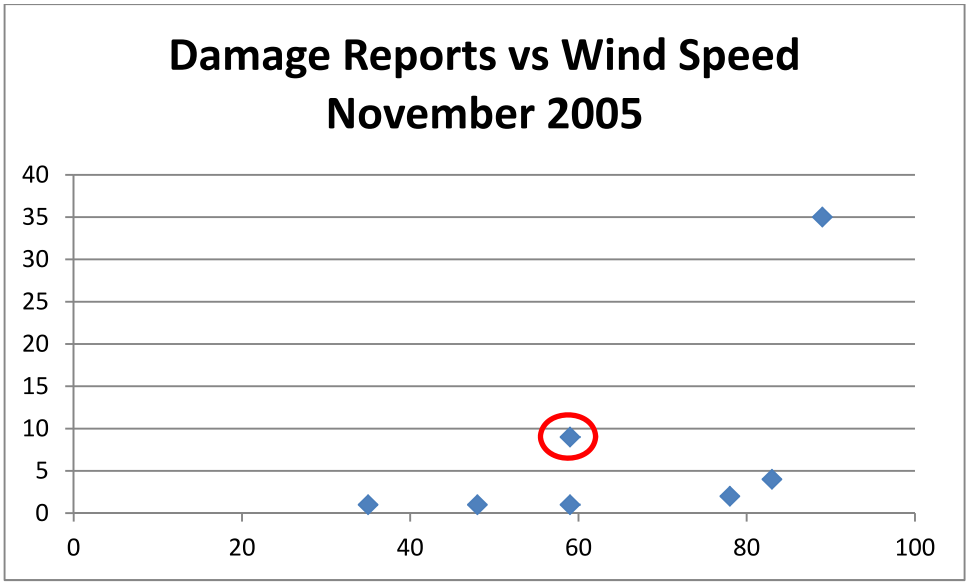

Figure C.9: Number of reports versus max gust reported for November 2005. Note the one apparent outlier, circled in **red**, is November 9th, in which localized impacts are expected and conditions at Pearson Airport are expected to be less representative of conditions producing impacts at a given site.

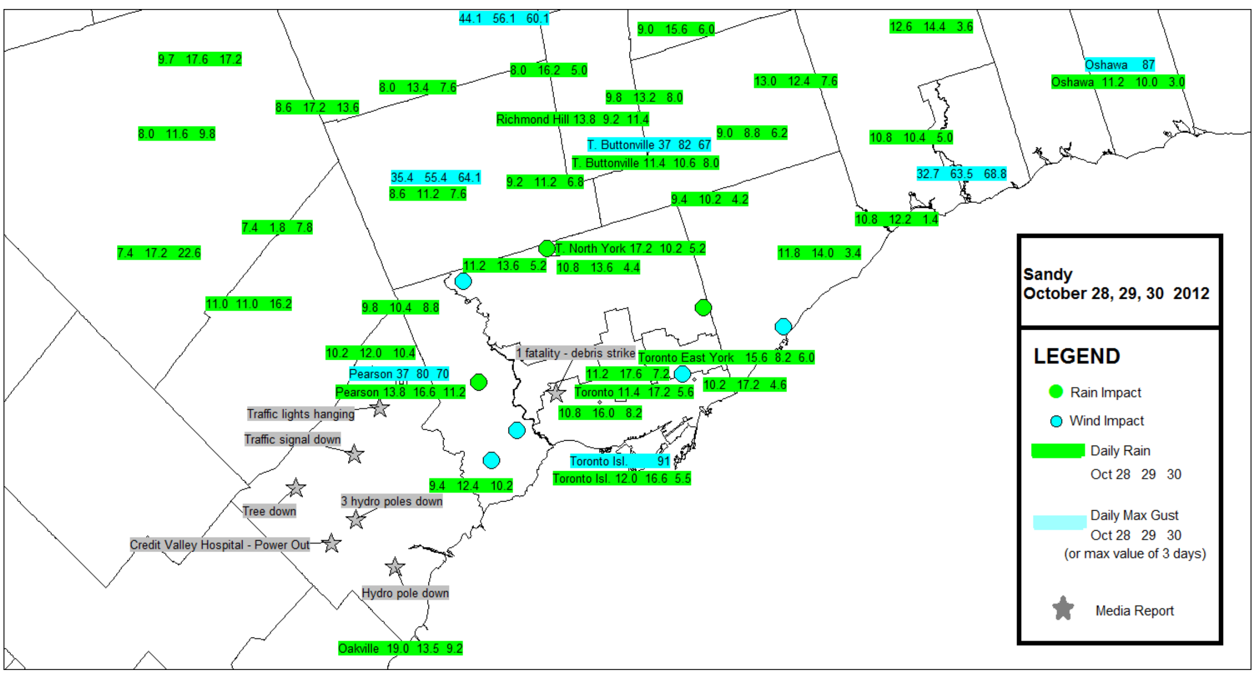

Figure C.10: Map comparing reported impacts with meteorological data for "Superstorm" Sandy. Meteorological data are for October 28th, 29th and 30th and help illustrate the progression of events. Precipitation and wind values are a combination of both EC and TRCA (2014) observational data.

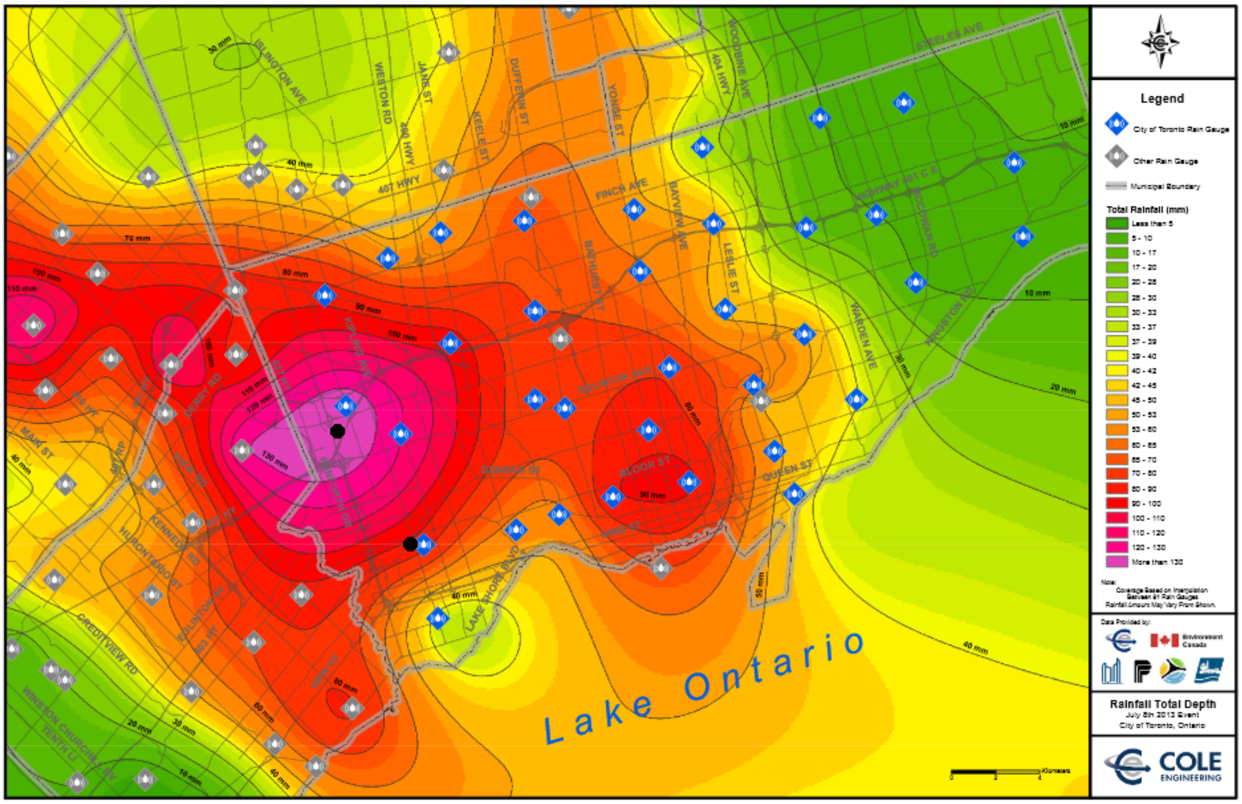

Figure C.11: Contoured 24 hour rainfall totals for the City of Toronto with the locations of Richview and Manby TS superimposed (black dots) added. High resolution PDF map of rainfall totals is available online: http://coleengineering.ca/wordpress/wp-content/themes/Evolution/pdf/2013-articles/rainfall-map.pdf (Cole Engineering Group, 2013)

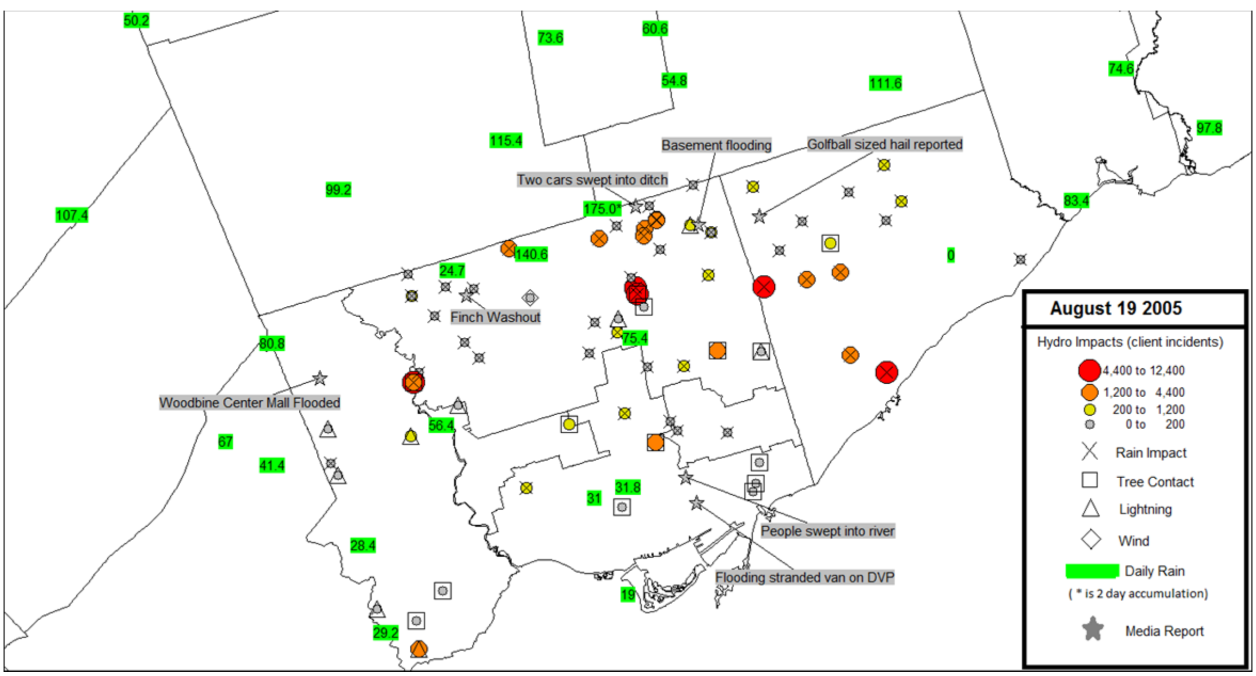

Figure C.12: August 19, 2005 severe thunderstorm event. Map of impacts combining impact types from ITIS and media reports with meteorological data.

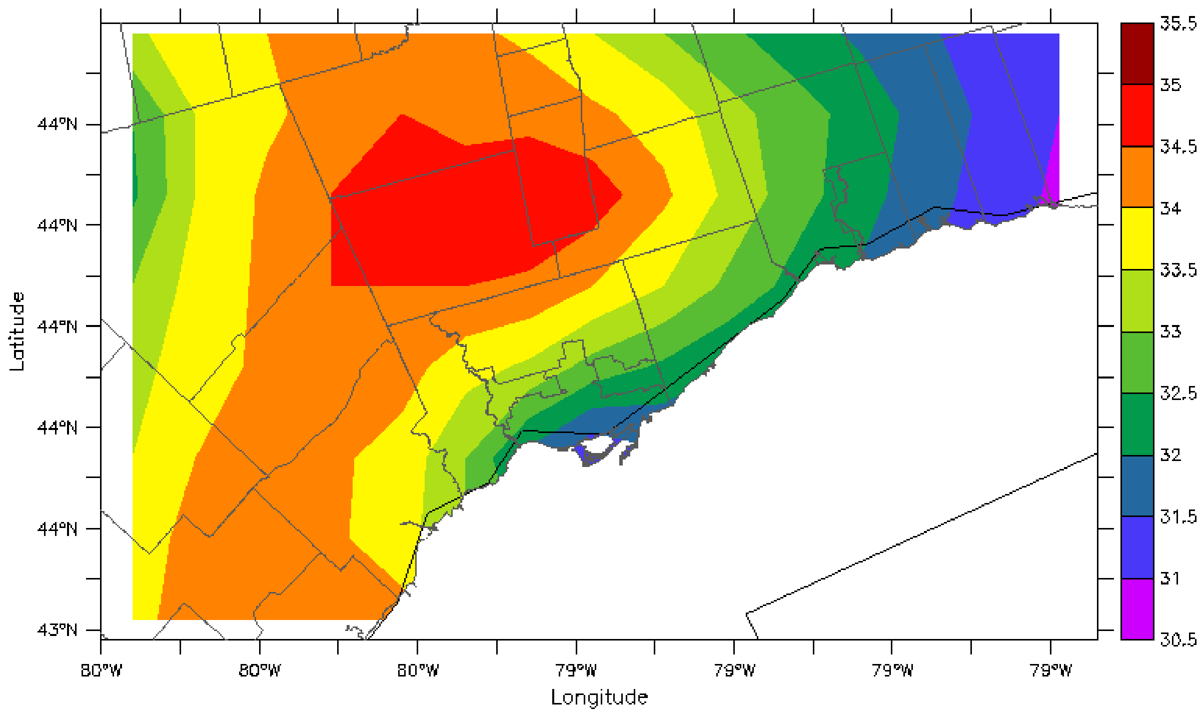

Figure C.13: July 16, 2006, maximum surface temperature (°C) for Toronto and surrounding areas. Data from Cangrd gridded data set.

Appendix D
Risk Assessment Matrix

Study Period / Infrastructure Class or Category	Evaluation: Load Projections/ Capacity / Redundancy	Other Comment	1 High Temperature						2 High Temperature					
			Maximum temp above 25 °C						Maximum temp above 30 °C					
			Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal														
1.1 Former Toronto														
1.1.1 Downtown core stations	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.1.2 Downtown outer stations w/o a station	Station capacity by 2050 : Low	Stations are indoors	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.1.3 Station (13.8 kV)	Station capacity by 2050 : Low	Outdoor station	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.2 Horseshoe Area														
1.2.1 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.2.2 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
1.2.3 East stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
1.2.4 Station	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.2.5 Station (27.6 kV)	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.2.6 Station	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
1.2.7 Northwest stations	Station capacity by 2050 : Good	Stations are outdoor stations	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
1.2.8 2 Stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
1.2.9 Southwest stations	Station capacity by 2050 : Low	Stations are outdoor stations	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
2 Municipal Stations (divided by geography)														
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship														
2.1.1 Former Toronto (indoor/outdoor)	Low	Most stations are located indoors in buildings	Y	7	Batteries: lifespan	2+	3	21	Y	7	Batteries: lifespan	2+	3	21
2.1.2 Horseshoe Area (indoor/outdoor)	Good	Most stations are located outdoors	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
2.1.3 Toronto Hydro to Private owner ship	n/a - no transfer possible	Stations are indoors	N	7			2	-1	N	7				-1
3 Feeder Configuration : Underground (divided by														
3.1 Horseshoe Area: Dual Radial System (underground) &														
3.1.1 Submersible type	moderate / usually serves multiple customers		N	7				-1	N	7	Ability to access service (see human resources)			-1
3.1.2 Vault type:														
- Above ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1
- Below ground	moderate / usually serves 1 customer		N	7				-1	N	7	idem			-1
3.1.3 Padmount station	moderate / usually serves multiple customers		N	7				-1	N	7	idem			-1
3.2 Former Toronto : Dual Radial System (underground) &														
3.2.1 Submersible type	low/ usually serves multiple customers		N	7				-1	N	7	idem			-1
3.2.2 Vault type:														
- Above ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1
- Below ground	low / usually serves 1 customer		N	7				-1	N	7	idem			-1
3.2.3 Padmount station	low / usually serves multiple customers		N	7				-1	N	7	idem			-1
3.3 Compact Loop Design (underground)														
3.3.1 Former Toronto: Subway type	Moderate to good		N	7				-1	N	7	idem			-1
3.4 13.8 kV Network														
3.4.1 Former Toronto	Best		N	7				-1	N	7	idem			-1
3 Feeder Configuration : Overhead (divided by														
3.5 Overhead														
Radial														
3.5.1 4.16 kV	Low / less affected		N	7				-1	N	7				-1
3.5.2 13.8 kV	Low / more affected		N	7				-1	N	7				-1
3.5.3 27.6 kV	Low / more affected		N	7				-1	N	7				-1
Loop														
3.5.4 4.16 kV	Good / less affected		N	7				-1	N	7				-1
3.5.5 13.8 kV	Good / more affected		N	7				-1	N	7				-1
3.5.6 27.6 kV	Good / more affected		N	7				-1	N	7				-1
4 Communications (divided by types)														
4.1 Protection and control systems			Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	N/A		N	7				-1	N	7				-1
5 Civil Structures (divided by categories)														
5.1 Transmission & Municipal Stations														
Outdoor														
5.1.1 Equipment support			N	7				-1	N	7				-1
5.1.2 Gantry			N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto														
5.2.1 Reinforced concrete cable chambers	Low		N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	Low		N	7				-1	N	7				-1
5.2.3 Underground cable ducts	Low		N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area														
5.3.1 Reinforced concrete cable chambers	moderate		N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	moderate		N	7				-1	N	7				-1
5.3.3 Underground cable ducts	moderate		N	7				-1	N	7				-1
6 Human Resources														
6.1 Emergency Response			N	7				-1	Y	7		2-3	3	21

Infrastructure Class or Category	3 High Temperature						4 High Temperature						5 Average temperature >30°C					
	Maximum temp above 35 °C						Maximum temp above 40 °C						Average temp. Over 30°C on a 24h basis					
	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal																		
1.1 Former Toronto																		
1.1.1 Downtown core stations	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.1.3 Station (13.8 kV)	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.2 Horseshoe Area																		
1.2.1 Station	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.2.2 Station	Y	7	Power transformer : Overload	3	3	21	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35
1.2.3 East stations	Y	7	Power transformer : Overload	3	3	21	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35
1.2.4 Station	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.2.5 Station (27.6 kV)	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.2.6 Station	Y	7	Power transformer : Overload	3	3	21	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35
1.2.7 Northwest stations	Y	7	Power transformer : Overload	3	3	21	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35
1.2.8 2 Stations	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
1.2.9 Southwest stations	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
2 Municipal Stations (divided by geography)																		
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship																		
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer: Overload - Load shedding	5+	6	42	Y	7	Power transformer: Overload - Load shedding	5+	6	42
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer : Overload	3	3	21	Y	7	Power transformer: Overload - Load shedding	5	5	35	Y	7	Power transformer: Overload - Load shedding	5	5	35
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer : Overload	3+	4	28	Y	7	Power transformer : Overload	5+	6	42	Y	7	Power transformer: Overload	5+	6	42
3 Feeder Configuration : Underground (divided by																		
3.1 Horseshoe Area: Dual Radial System (underground) &																		
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14
- Below ground	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14
3.1.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	2	2	14	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21
3.2 Former Toronto : Dual Radial System (underground) &																		
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.2 Vault type:																		
- Above ground	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21
- Below ground	Y	7	High demand: Stressed cables and transformers	2+	3	21	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	2+	3	21
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	2+	3	21	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28
3.3 Compact Loop Design (underground)																		
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14
3.4 13.8 kV Network																		
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	2	2	14	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	2	2	14
3 Feeder Configuration : Overhead (divided by																		
3.5 Overhead																		
Radial																		
3.5.1 4.16 kV	Y	7	Onan power transformers, conductors	2+	3	21	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35
3.5.2 13.8 kV	Y	7	Onan power transformers, conductors	2+	3	21	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35
3.5.3 27.6 kV	Y	7	Onan power transformers, conductors	2+	3	21	Y	7	Onan power transformers, conductors	4+	5	35	Y	7	Onan power transformers, conductors	4+	5	35
Loop																		
3.5.4 4.16 kV	Y	7	Onan power transformers, conductors	2	2	14	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28
3.5.5 13.8 kV	Y	7	Onan power transformers, conductors	2	2	14	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28
3.5.6 27.6 kV	Y	7	Onan power transformers, conductors	2	2	14	Y	7	Onan power transformers, conductors	4	4	28	Y	7	Onan power transformers, conductors	4	4	28
4 Communications (divided by types)																		
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	N	7				-1	Y	7	Interrupters: Unusual conditions with temp over 40°C	1	1	7	N	7				-1
5 Civil Structures (divided by categories)																		
5.1 Transmission & Municipal Stations																		
Outdoor																		
5.1.1 Equipment support	N	7				-1	N	7				-1	N	7				-1
5.1.2 Gantry	N	7				-1	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto																		
5.2.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area																		
5.3.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	N	7				-1	N	7				-1	N	7				-1
6 Human Resources																		
6.1 Emergency Response	Y	7		4	4	28	Y	7	health issue	5	5	35	Y	7	health issue	4	4	28

Infrastructure Class or Category	6 Heat Wave						7 High Nighttime Temperatures					
	3 days with max temp. above 30 °C						Min temp ≥ 23°C					
	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal												
1.1 Former Toronto												
1.1.1 Downtown core stations	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.1.2 Downtown outer stations w/o a station	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.1.3 Station (13.8 kV)	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.2 Horseshoe Area												
1.2.1 Station	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.2.2 Station	Y	7	Power transformer: Overload - Load shedding	4	4	28	Y	7	Power transformer: Overload - Load shedding	3	3	21
1.2.3 East stations	Y	7	Power transformer: Overload - Load shedding	4	4	28	Y	7	Power transformer: Overload - Load shedding	3	3	21
1.2.4 Station	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.2.5 Station (27.6 kV)	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.2.6 Station	Y	7	Power transformer: Overload - Load shedding	4	4	28	Y	7	Power transformer: Overload - Load shedding	3	3	21
1.2.7 Northwest stations	Y	7	Power transformer: Overload - Load shedding	4	4	28	Y	7	Power transformer: Overload - Load shedding	3	3	21
1.2.8 2 Stations	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
1.2.9 Southwest stations	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
2 Municipal Stations (divided by geography)												
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship												
2.1.1 Former Toronto (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	4+	5	35	Y	7	Power transformer: Overload - Load shedding	3+	4	28
2.1.2 Horseshoe Area (indoor/outdoor)	Y	7	Power transformer: Overload - Load shedding	4	4	28	Y	7	Power transformer: Overload - Load shedding	3	3	21
2.1.3 Toronto Hydro to Private owner ship	Y	7	Power transformer: Overload	3+	4	28	Y	7	Power transformer: Overload	3+	4	28
3 Feeder Configuration : Underground (divided by												
3.1 Horseshoe Area: Dual Radial System (underground) &												
3.1.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.2 Vault type:												
- Above ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	3	3	21
- Below ground	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	3	3	21
3.1.3 Padmount station	Y	7	Pad mount transformers overheating	3	3	21	Y	7	Pad mount transformers overheating	3	3	21
3.2 Former Toronto : Dual Radial System (underground) &												
3.2.1 Submersible type	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.2 Vault type:												
- Above ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	3+	4	28
- Below ground	Y	7	High demand: Stressed cables and transformers	3+	4	28	Y	7	High demand: Stressed cables and transformers	3+	4	28
3.2.3 Padmount station	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28	Y	7	Pad mount transformers overheating, cables stressed	3+	4	28
3.3 Compact Loop Design (underground)												
3.3.1 Former Toronto: Subway type	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	3	3	21
3.4 13.8 kV Network												
3.4.1 Former Toronto	Y	7	High demand: Stressed cables and transformers	3	3	21	Y	7	High demand: Stressed cables and transformers	3	3	21
3 Feeder Configuration : Overhead (divided by												
3.5 Overhead												
Radial												
3.5.1 4.16 kV	Y	7	Onan power transformers, conductors	3+	4	28	Y	7	Onan power transformers	1+	2	14
3.5.2 13.8 kV	Y	7	Onan power transformers, conductors	3+	4	28	Y	7	Onan power transformers	1+	2	14
3.5.3 27.6 kV	Y	7	Onan power transformers, conductors	3+	4	28	Y	7	Onan power transformers	1+	2	14
Loop												
3.5.4 4.16 kV	Y	7	Onan power transformers, conductors	3	3	21	Y	7	Onan power transformers	1	1	7
3.5.5 13.8 kV	Y	7	Onan power transformers, conductors	3	3	21	Y	7	Onan power transformers	1	1	7
3.5.6 27.6 kV	Y	7	Onan power transformers, conductors	3	3	21	Y	7	Onan power transformers	1	1	7
4 Communications (divided by types)												
4.1 Protection and control systems	Y	7	Batteries: lifespan	2	2	14	Y	7	Batteries: lifespan	2	2	14
4.2 SCADA + Wireless network	N	7				-1	N	7				-1
5 Civil Structures (divided by categories)												
5.1 Transmission & Municipal Stations												
Outdoor												
5.1.1 Equipment support	N	7				-1	N	7				-1
5.1.2 Gantry	N	7				-1	N	7				-1
5.2 Underground feeders : Former Toronto												
5.2.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1
5.2.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1
5.2.3 Underground cable ducts	N	7				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area												
5.3.1 Reinforced concrete cable chambers	N	7				-1	N	7				-1
5.3.2 Concrete vaults (reinforced)	N	7				-1	N	7				-1
5.3.3 Underground cable ducts	N	7				-1	N	7				-1
6 Human Resources												
6.1 Emergency Response	Y	7	health issue	4	4	28	Y	7		0	0	0

Infrastructure Class or Category	8 Extreme Rainfall						9 Freezing Rain/Ice Storm					
	100 mm <1 day + antecedent						15 mm (tree branches)					
	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
1 Transmission Step-down to Municipal												
1.1 Former Toronto												
1.1.1 Downtown core stations	Y	2	Probability of flood is low due to sump pumps in stations, 5 stations have batteries/switchgear in basement, but batteries will be moved by 2030s. Some stations will still have switchgear in basement	1+	2	4	N	7				-1
1.1.2 Downtown outer stations w/o a station	Y	2		1+	2	4	N	7				-1
1.1.3 Station (13.8 kV)	Y	2		1+	2	4	Y	7	Access to station equipment	1	1	7
1.2 Horseshoe Area												
1.2.1 Station	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.2 Station	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.3 East stations	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.4 Station	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.5 Station (27.6 kV)	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.6 Station	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.7 Northwest stations	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.8 2 Stations	N	6				-1	Y	7	Access to station equipment	1	1	7
1.2.9 Southwest stations	N	6				-1	Y	7	Access to station equipment	1	1	7
2 Municipal Stations (divided by geography)												
2.1 Toronto Hydro to Toronto Hydro & Private owner Ship												
2.1.1 Former Toronto (indoor/outdoor)	N	6	No batteries in basement by 2030s	6	6	-1	N	7				-1
2.1.2 Horseshoe Area (indoor/outdoor)	N	6	No batteries in basement by 2030s	6	6	-1	Y	7	Access to station equipment	0	0	0
2.1.3 Toronto Hydro to Private owner ship	N	6				-1	N	7				-1
3 Feeder Configuration : Underground (divided by												
3.1 Horseshoe Area: Dual Radial System (underground) &												
3.1.1 Submersible type	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.2 Vault type:												
- Above ground	Y	6	Access	1	1	6	N	7				-1
- Below ground	Y	6	All electrical components (not submersible), + 2 if pumps fails	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.1.3 Padmount station	Y	6	Access	1	1	6	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.2 Former Toronto : Dual Radial System (underground) &												
3.2.1 Submersible type	Y	6	Water treeing, flooding, reduced dielectric strength	3+	4	24	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.2 Vault type:												
- Above ground	Y	6	Access	1+	2	12	N	7				-1
- Below ground	Y	6	All electrical components (not submersible), + 2 if pumps fails	5+	6	36	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.2.3 Padmount station	Y	6	Access	1+	2	12	Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14
3.3 Compact Loop Design (underground)												
3.3.1 Former Toronto: Subway type	Y	6	Water treeing, flooding, reduced dielectric strength	3	3	18	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3.4 13.8 kV Network												
3.4.1 Former Toronto	Y	6	Old N/W protectors are not submersible	5	5	30	Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7
3 Feeder Configuration : Overhead (divided by												
3.5 Overhead												
Radial												
3.5.1 4.16 kV	N	6	Note: severity score for light rainfall. Mist + humidity = Visibility.	1+	2	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.2 13.8 kV	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
3.5.3 27.6 kV	N	6	idem.	3+	4	-1	Y	7	Conductors (tree contacts)	5+	6	42
Loop												
3.5.4 4.16 kV	N	6	Note: severity score for light rainfall: Mist + humidity = Visibility.	1	1	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.5 13.8 kV	N	6	Severity score for light rainfall. Mist + humidity = Visibility. Light rainfall + dirt = flash over	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
3.5.6 27.6 kV	N	6	idem	3	3	-1	Y	7	Conductors (tree contacts)	5	5	35
4 Communications (divided by types)												
4.1 Protection and control systems	N	6	Batteries will be moved to ground floor by 2030s	6	6	-1	N	7				-1
4.2 SCADA + Wireless network	N	6				-1	N	7				-1
5 Civil Structures (divided by categories)												
5.1 Transmission & Municipal Stations												
Outdoor												
5.1.1 Equipment support	Y	6	Corrosion	0	0	0	N	7				-1
5.1.2 Gantry	Y	6	Corrosion	0	0	0	N	7				-1
5.2 Underground feeders : Former Toronto												
5.2.1 Reinforced concrete cable chambers	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.2 Concrete vaults (reinforced)	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	12	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14
5.2.3 Underground cable ducts	N	6				-1	N	7				-1
5.3 Underground feeders : Horseshoe Area												
5.3.1 Reinforced concrete cable chambers	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.2 Concrete vaults (reinforced)	Y	6	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	6	Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7
5.3.3 Underground cable ducts	N	6				-1	N	7				-1
6 Human Resources												
6.1 Emergency Response	Y	6	access to site, delays, rain to stop	2-3	3	18	Y	7	safe access to site	4	4	28

Toronto Hydro Climate Change Risk Assessment Workshop

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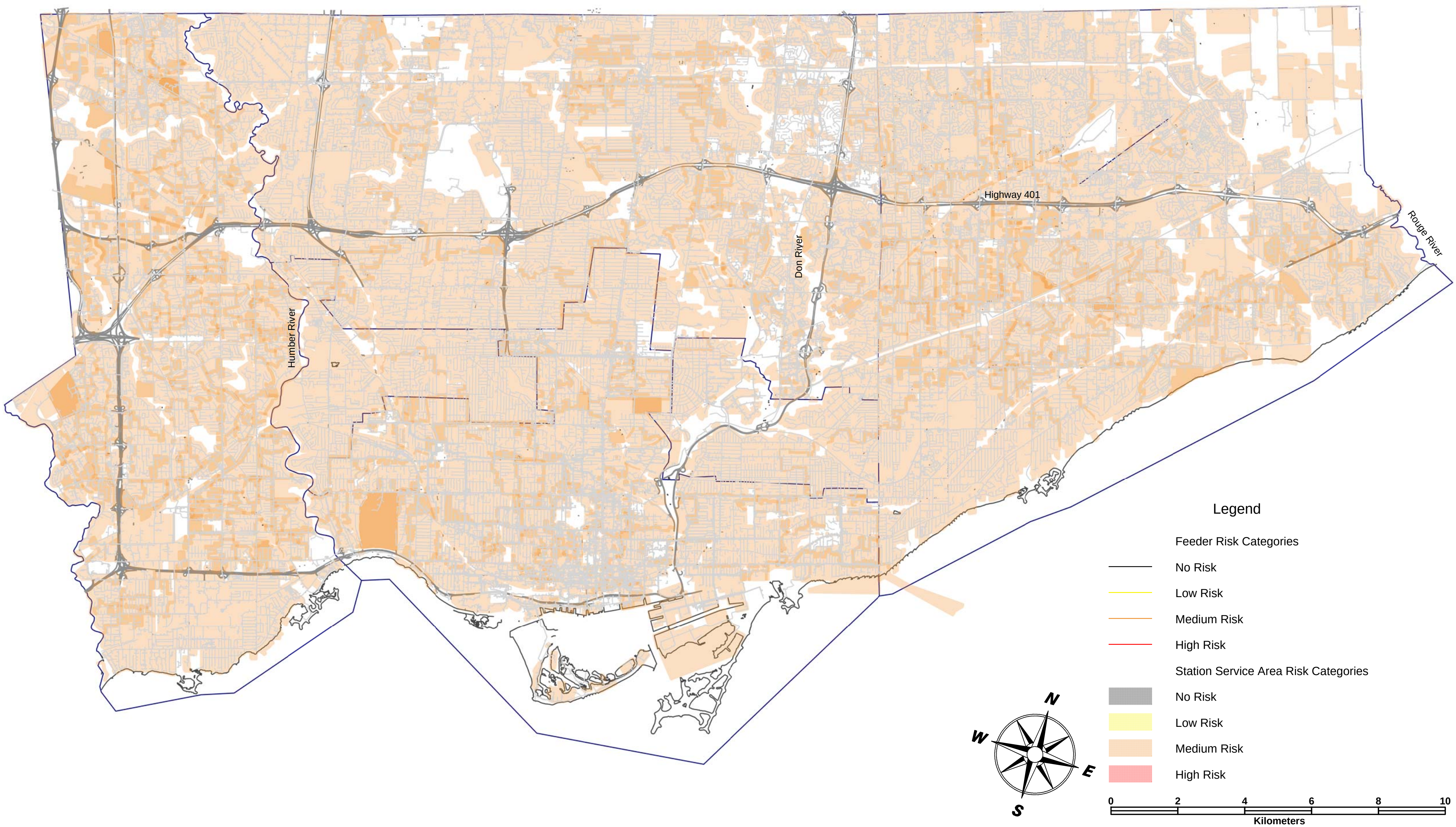
10		Freezing Rain/Ice Storm				11		Freezing Rain/Ice Storm				12		High Winds				13		High Winds				14		High Winds			
		25 mm (design threshold)						60 mm(major outages)						70 km/h+ (tree branches)						90 km/h (min design value; TH higher??)						120 km/h			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	7	7	49
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Exit lines	6	6	42	Y	4	Exit lines: overhead	7	7	28	N	7				-1	N	7				-1	Y	7	Exit lines, and flying debris could impact the equipement	6	6	42
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1		7				0	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4		7				0	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1	Y	7	Debris could impact the equipement	1	1	7
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7				-1	N	7				-1	Y	7	Debris could impact the equipement	1+	2	14
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1	N	7				-1
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				-1	N	7				-1	N	7				-1
																								Y					
Y	7	Poles & conductors downed, Salt+Contamination	6+	7	49	Y	4	Poles & conductors downed, Salt+Contamination	6+	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49
Y	7	Poles & conductors downed, Salt+Contamination	6	6	42	Y	4	Poles & conductors downed, Salt+Contamination	6	6	24	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Access	1	1	7	Y	4	Access	1	1	4	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1	Y	7	TC & CVT structures			0
Y	7	Gantry + exit lines	1	1	7	Y	4	Gantry + exit lines	7	7	28	N	7				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1	N	7				-1
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7				-1	N	7				-1	N	7				-1
N	7				-1	N	4				-1	N	7				-1	N	7				-1	N	7				-1
Y	7	safe access to site	6	6	42	Y	4	safe access to site	6	6	24	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14

15		Tornadoes				16		Tornadoes				17		Lightning				18		Snow				19		Snow				20		Frost (ground)			
		EF1+						EF2+ (concrete poles, permanent structures)												Days with > 5 cm						Days with > 10 cm						Extreme cold weather			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6				-1	N	7				-1	N	7				-1	N	7				-1
Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7				-1	N	7				-1	N	7				-1
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	1	Pad mount equipment can be damaged	2	2	2	Y	0	Pad mount equipment can be damaged	2	2	0	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
																							0						0						
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
Y	1	Pad mount equipment can be damaged	2+	3	3	Y	0	Pad mount equipment can be damaged	2+	3	0	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7				-1
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	N	7				-1
N	1				-1	N	0				-1	Y	6	Equipment could fail if protection won't work	3	3	18	N	7				-1	N	7				-1	N	7				-1
Y	1	All supports	7	7	7	Y	0	All supports	7	7	0	N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
Y	1	Gantry	7	7	7	Y	0	Gantry	7	7	0	N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	2	2	14
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1+	2	14
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	1				-1	N	0				-1	N	6				-1	Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	1				-1	N	0				-1	N	6				-1	N	7				-1	N	7				-1	Y	7	Foundations, frost heave	1	1	7
Y	1	access, location has to be declare safe	2	2	2	Y	0	access, location has to be declare safe	2	2	0	Y	6	staff security	3-4	4	24	Y	7	Access, staff security	1-2	2	14	Y	7	Access, staff security	3	3	21	N	7				

Appendix E
Risk Maps

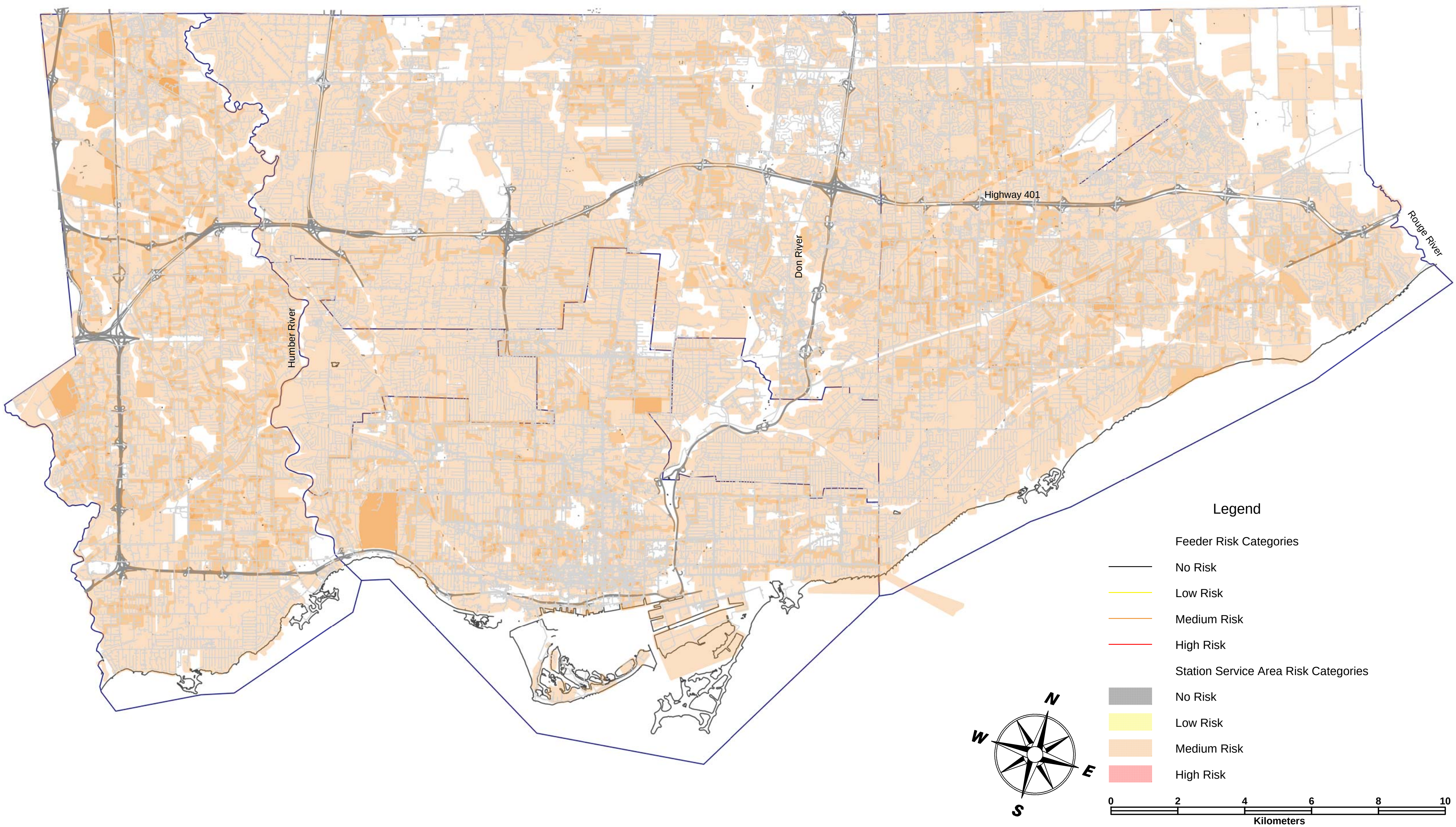
PIEVC Phase 2 Climate Change Risk Map by 2050

1. High Temperature Maximum Above 25 C



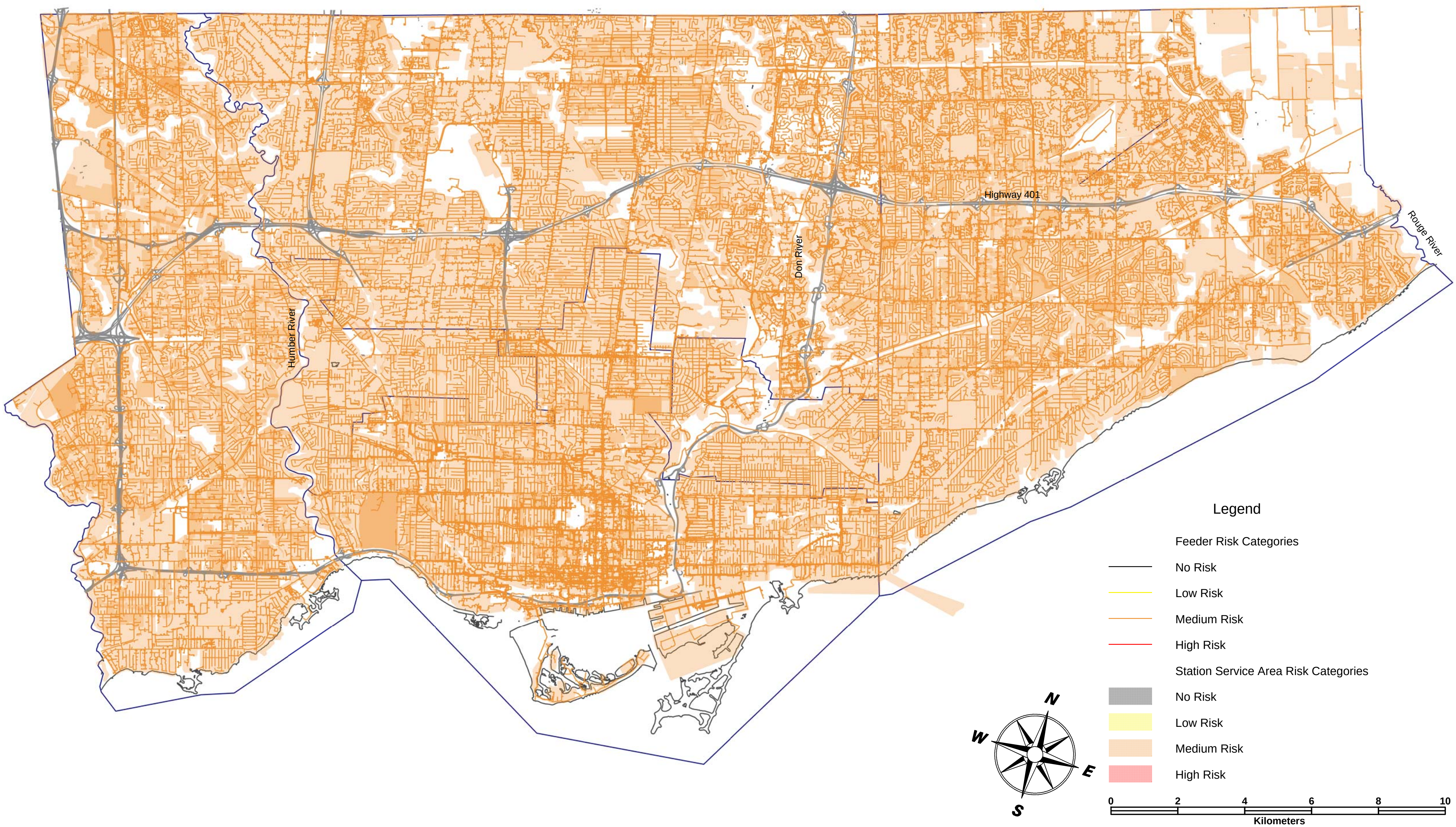
PIEVC Phase 2 Climate Change Risk Map by 2050

2. High Temperature Maximum Above 30 C



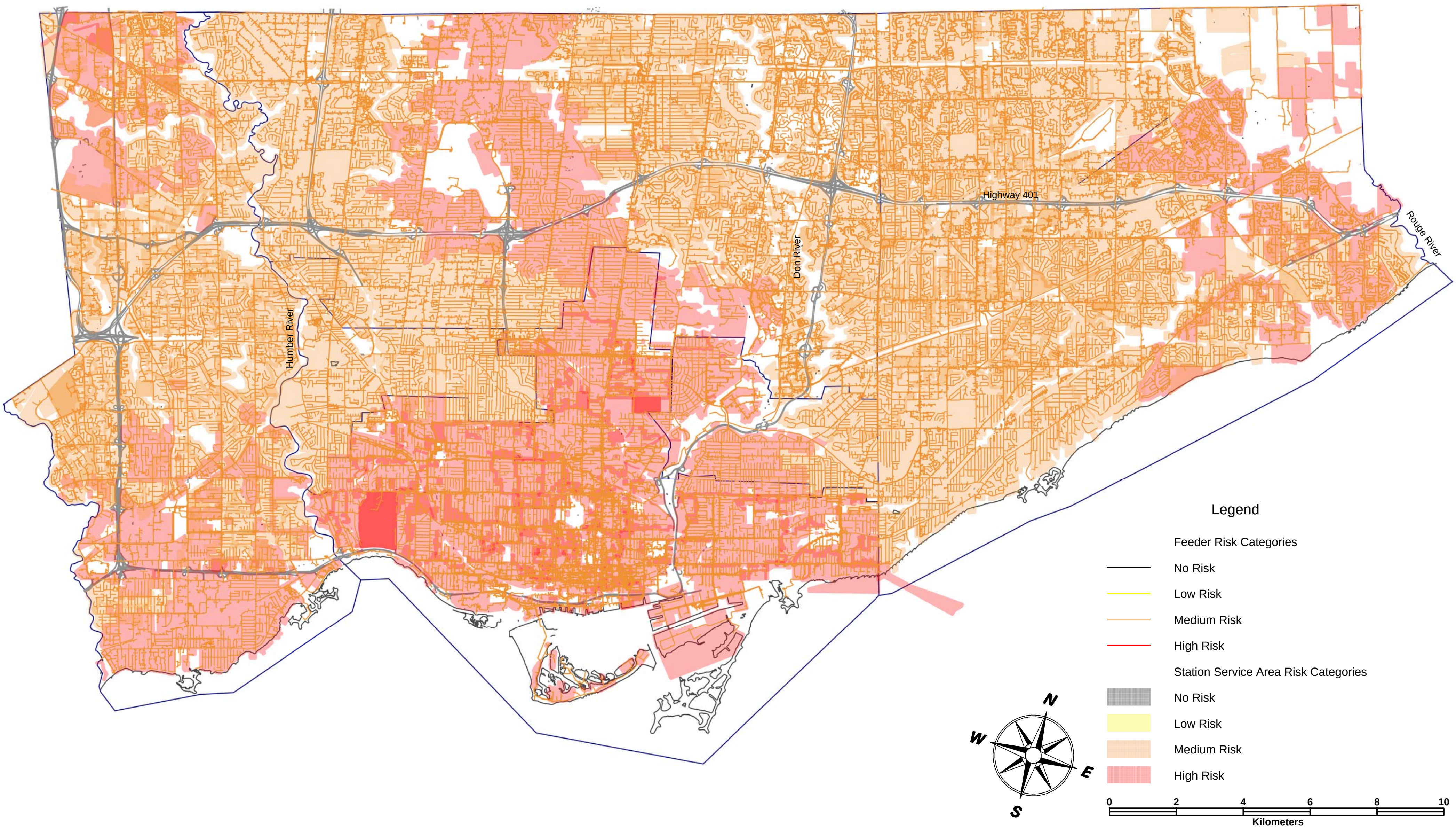
PIEVC Phase 2 Climate Change Risk Map by 2050

3. High Temperature Maximum Above 35 C



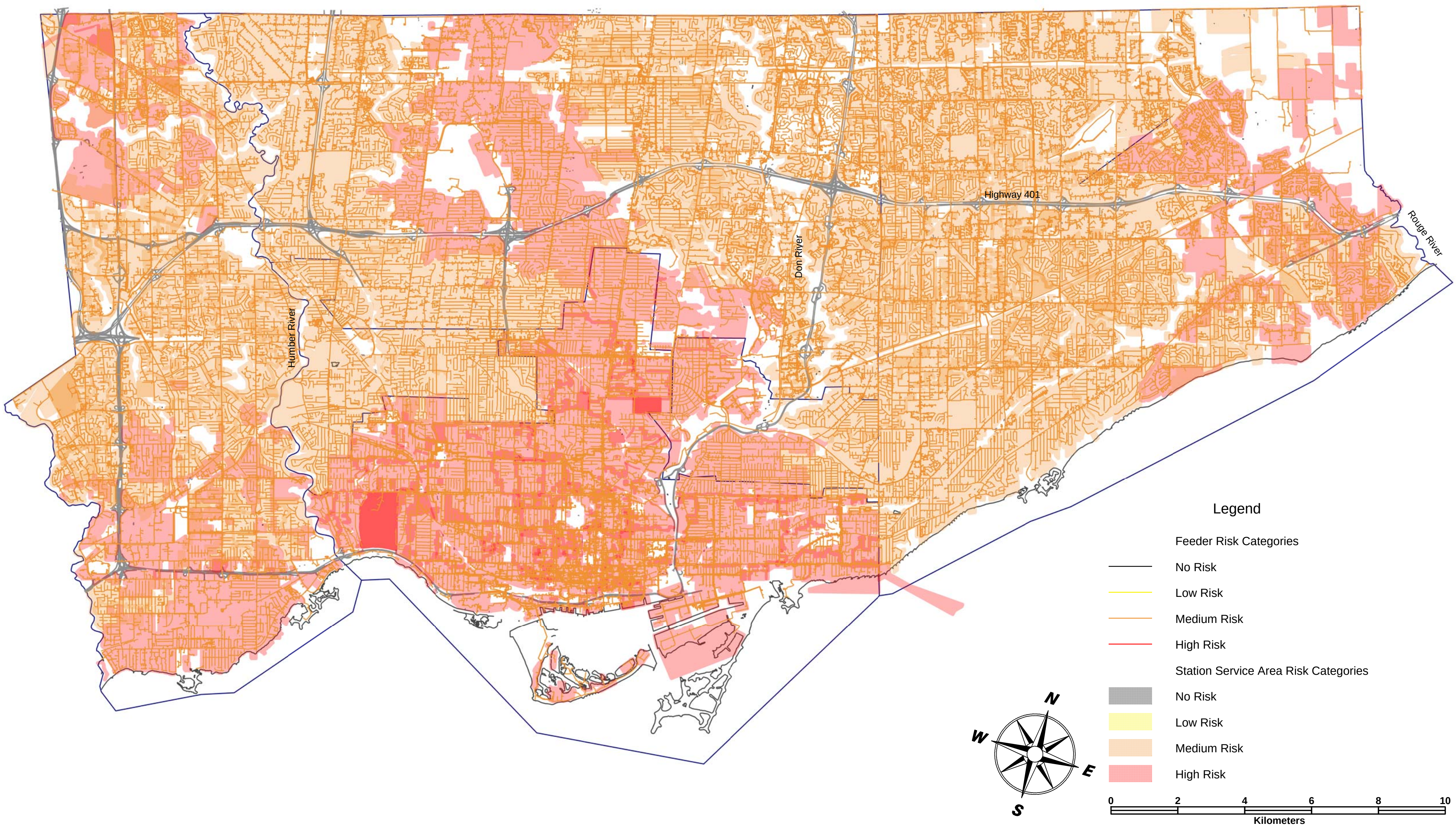
PIEVC Phase 2 Climate Change Risk Map by 2050

4. High Temperature Maximum Above 40 C



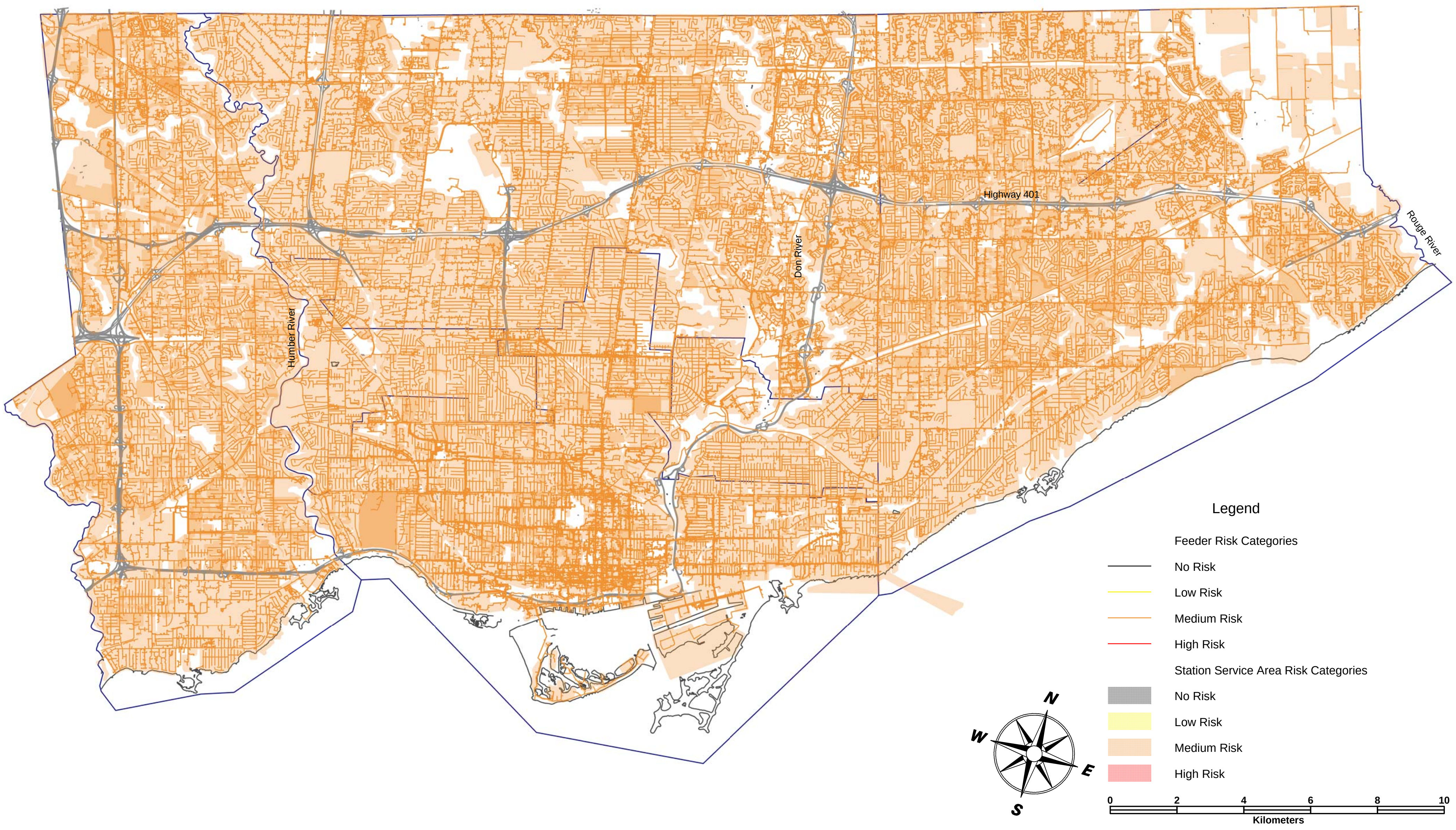
PIEVC Phase 2 Climate Change Risk Map by 2050

5. Average Temperature Above 30 C for 24 Hours



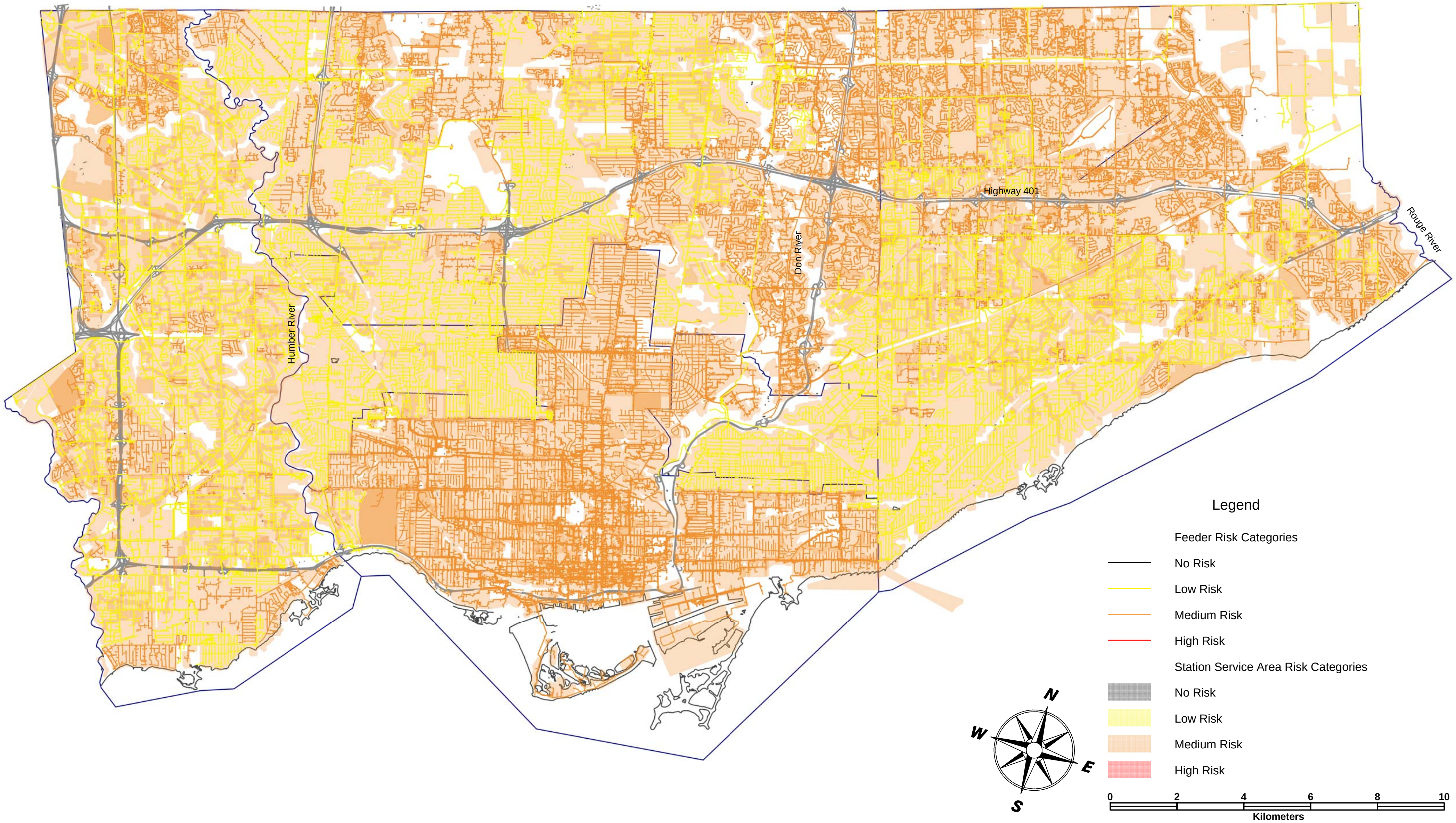
PIEVC Phase 2 Climate Change Risk Map by 2050

6. Heat Wave 3 Day with Maximum Temperature Above 30 C



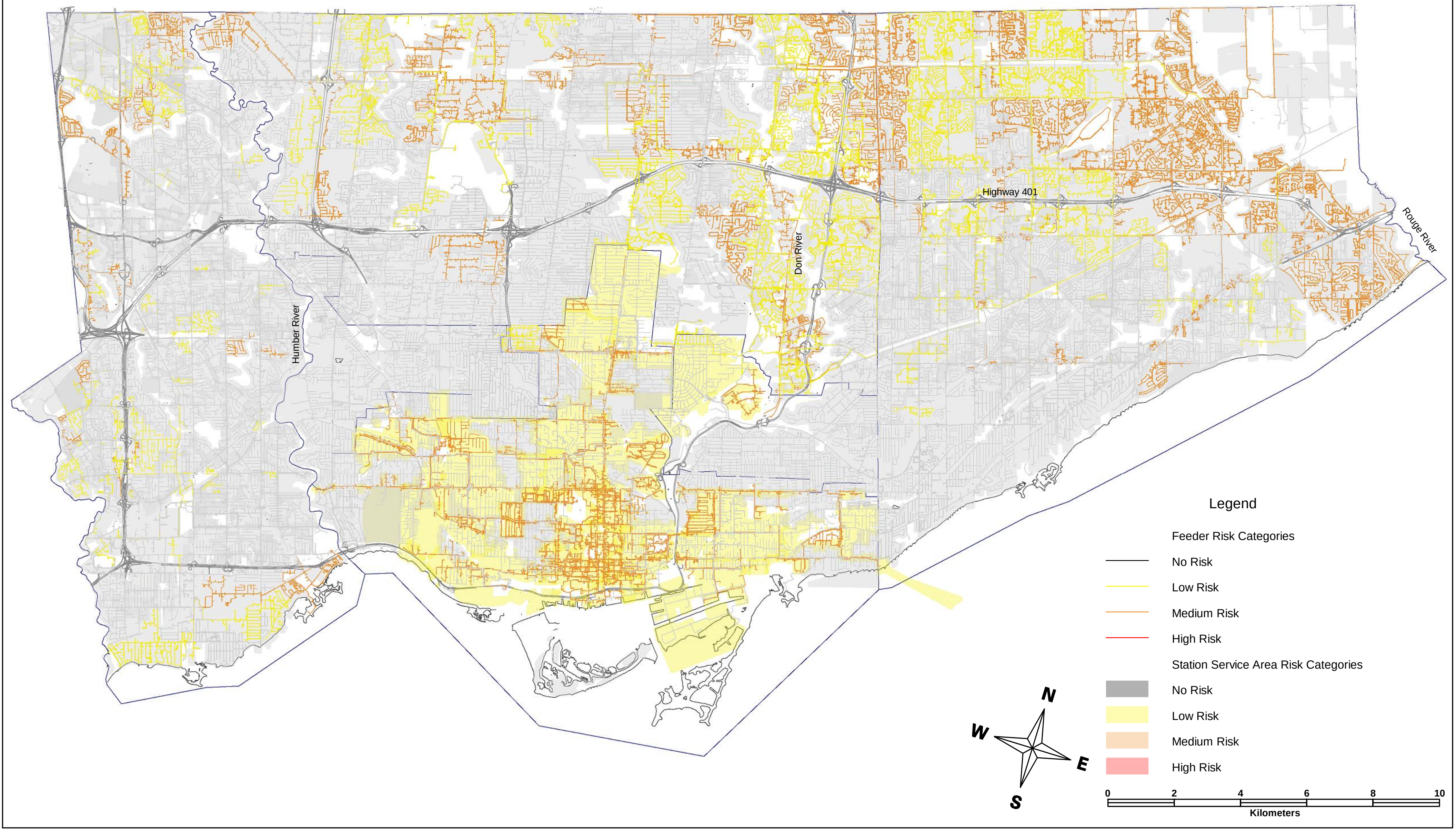
PIEVC Phase 2 Climate Change Risk Map by 2050

7. High Night Time Temperature Minimum Above 23 C



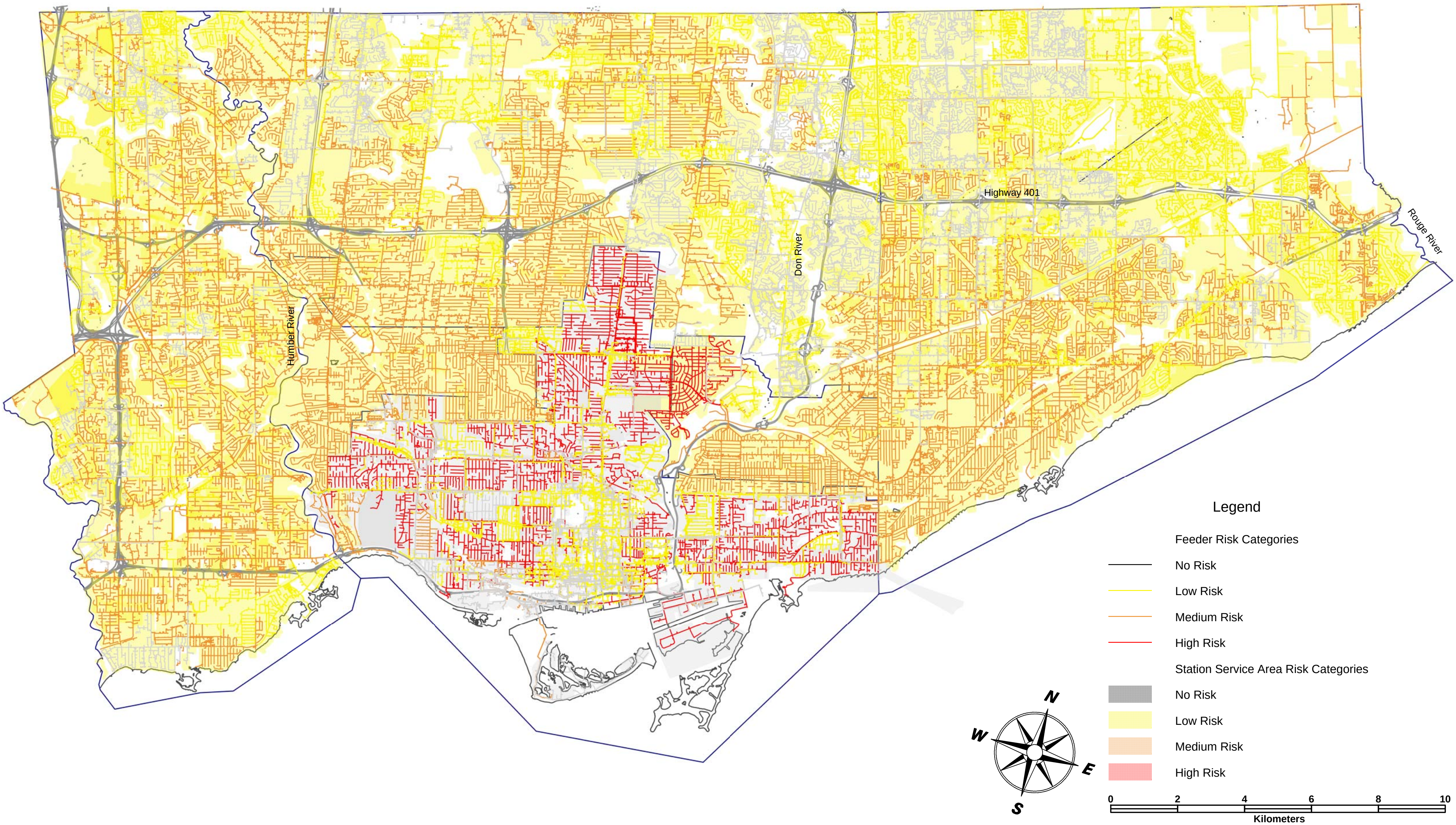
PIEVC Phase 2 Climate Change Risk Map by 2050

8. Extreme Rainfall 100mm in Less than 24 Hours



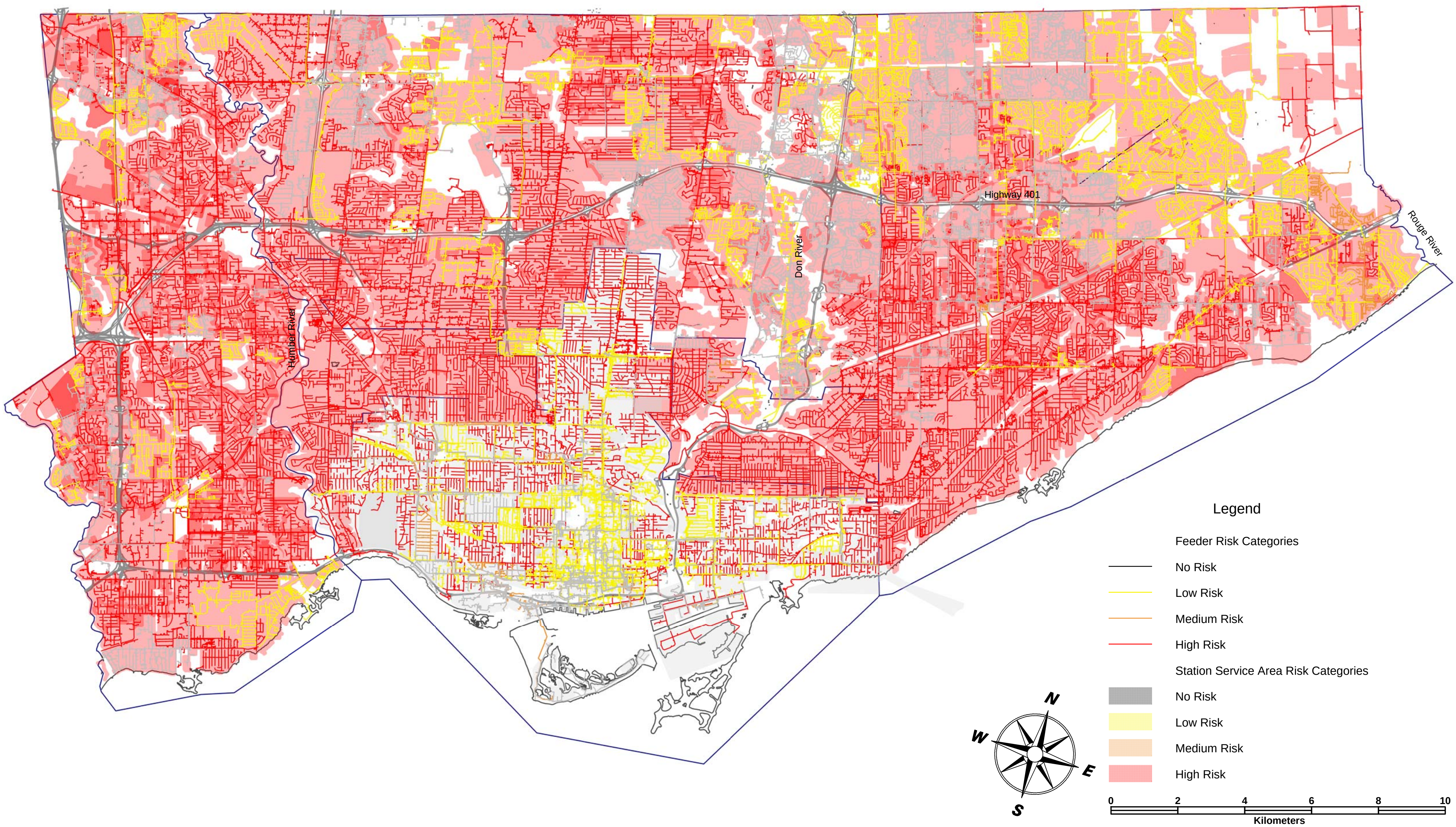
PIEVC Phase 2 Climate Change Risk Map by 2050

9. 15mm Freezing Rain/Ice Storm



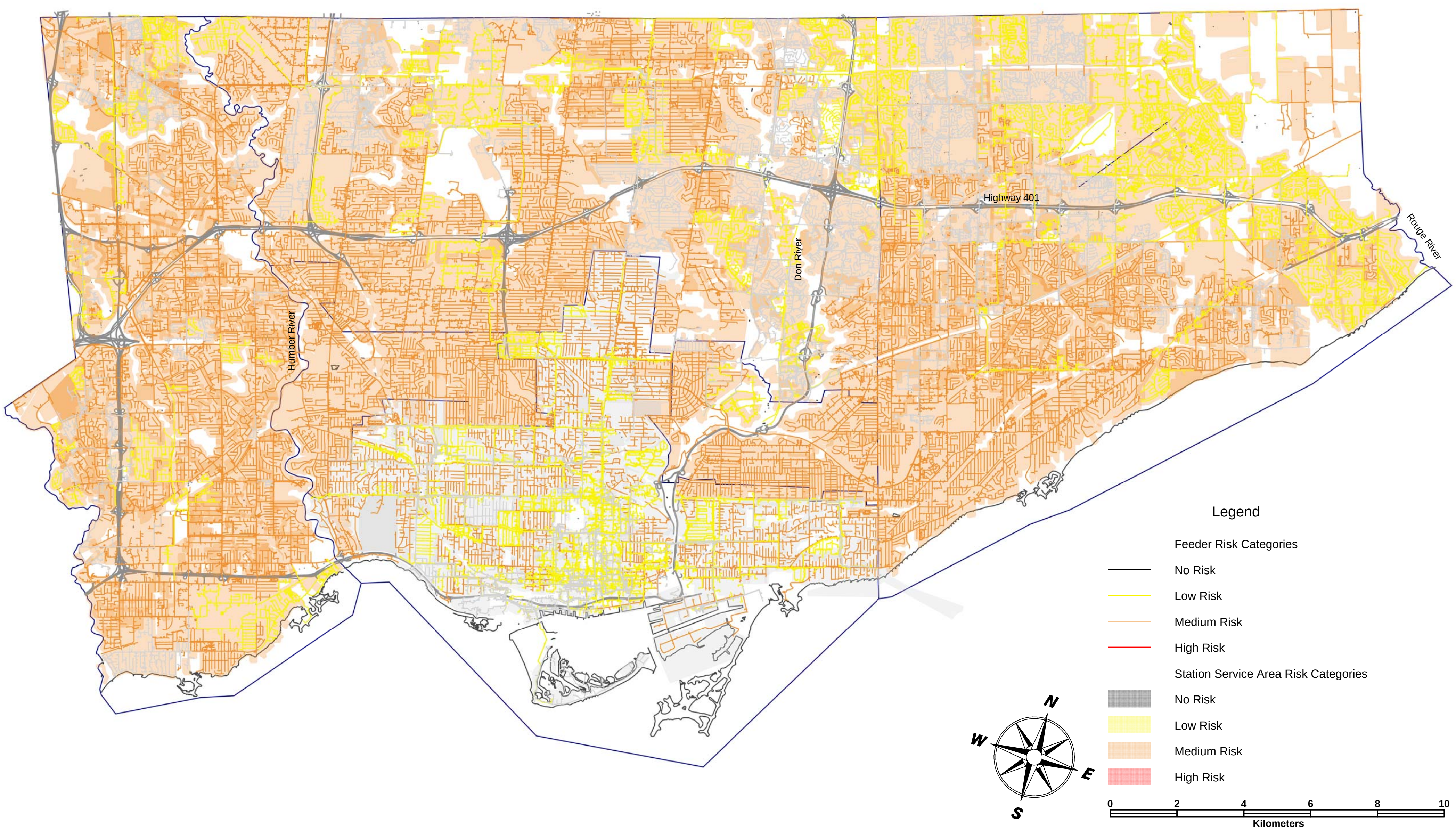
PIEVC Phase 2 Climate Change Risk Map by 2050

10. 25mm Freezing Rain/Ice Storm



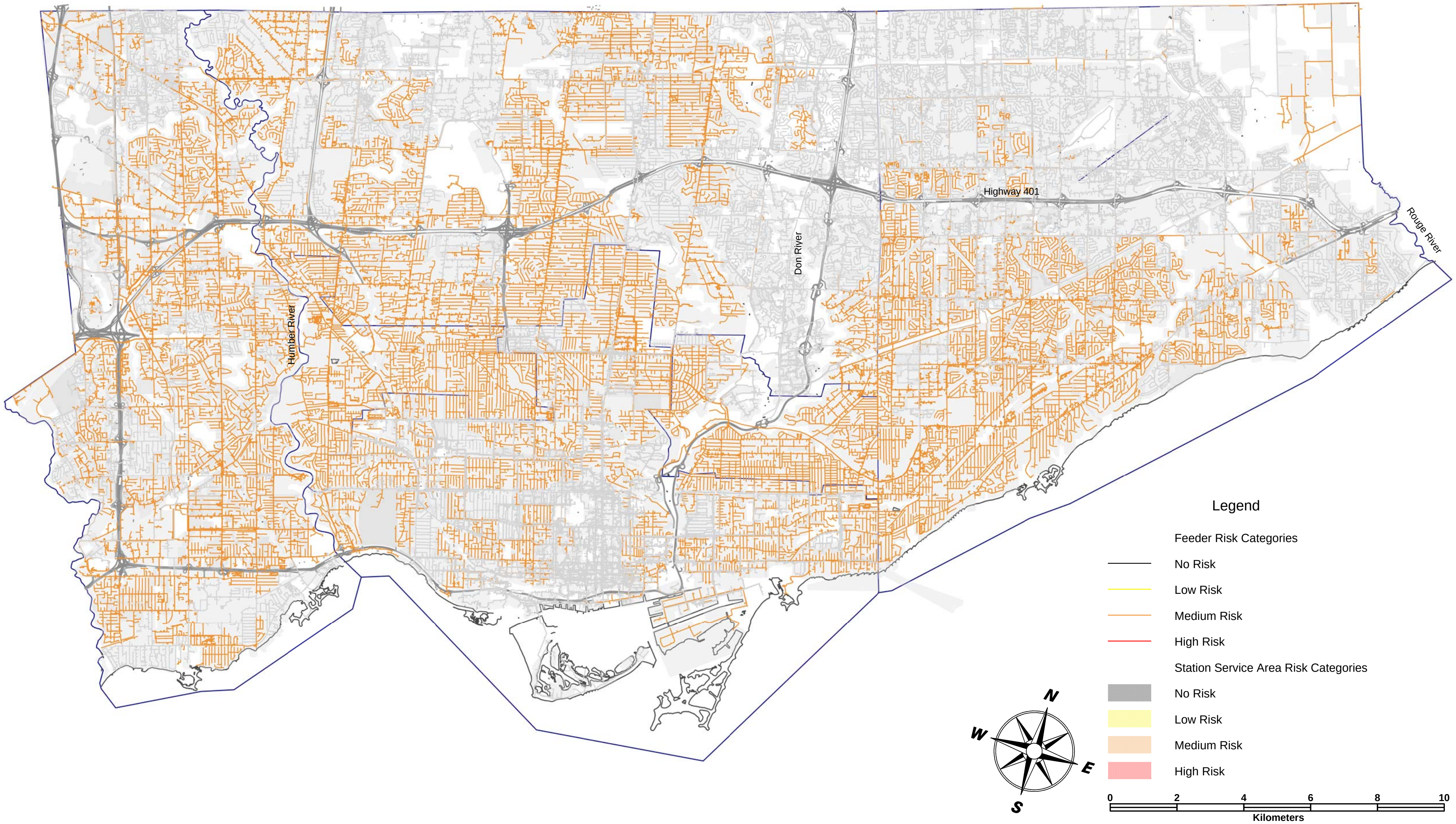
PIEVC Phase 2 Climate Change Risk Map by 2050

11. 60mm Freezing Rain/Ice Storm



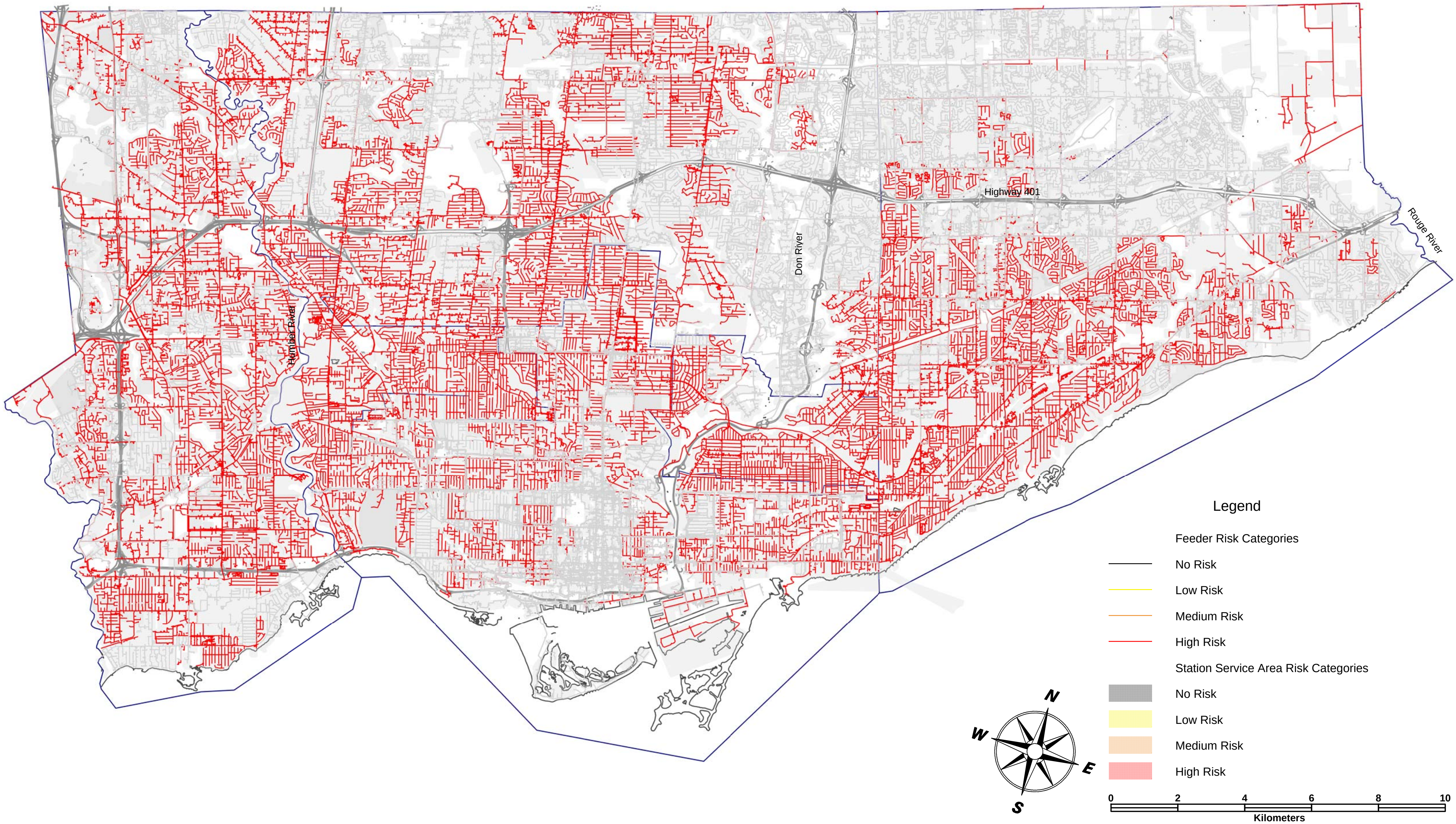
PIEVC Phase 2 Climate Change Risk Map by 2050

12. High Winds Greater Than 70km/h



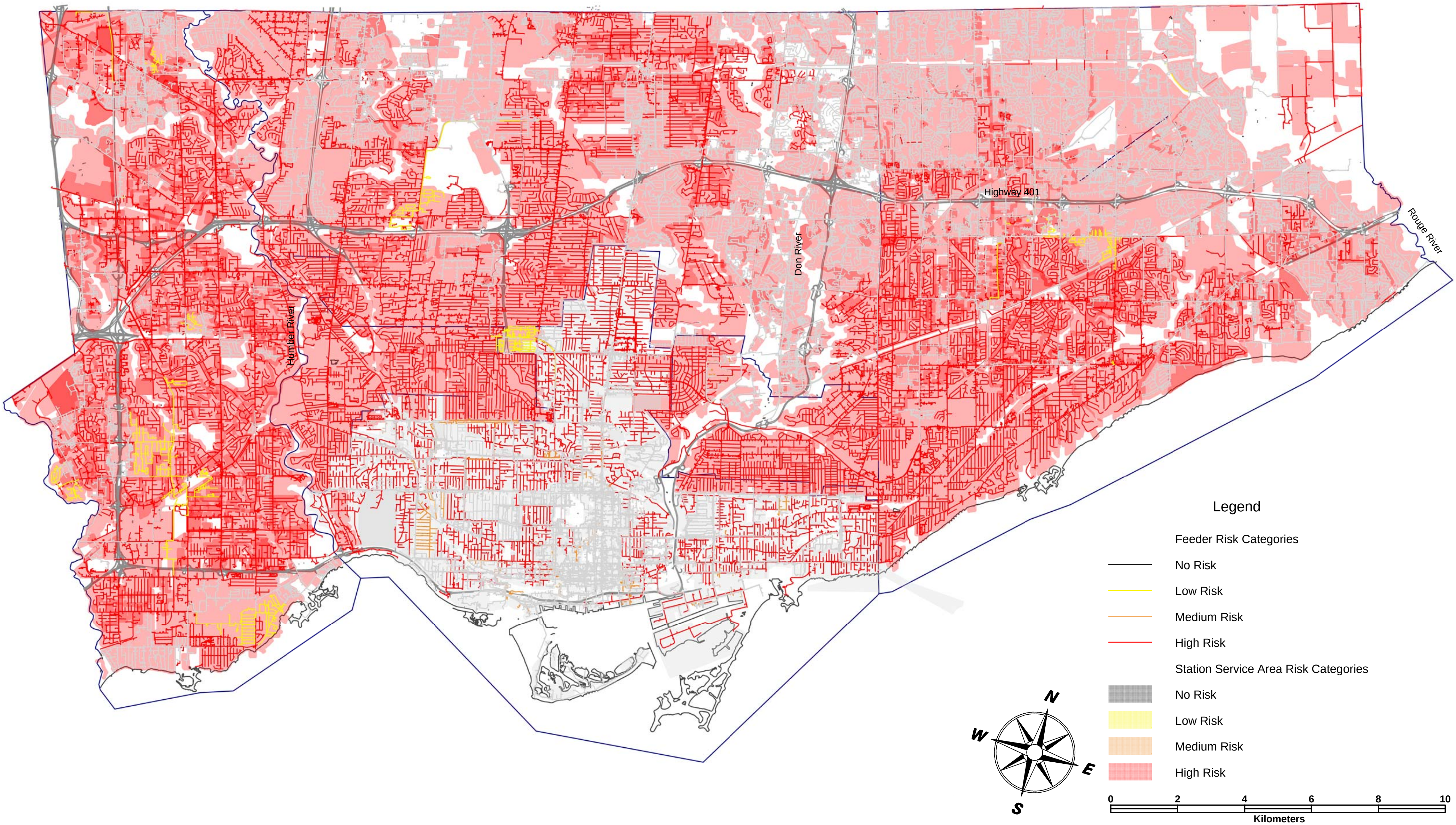
PIEVC Phase 2 Climate Change Risk Map by 2050

13. High Winds Greater Than 90km/h



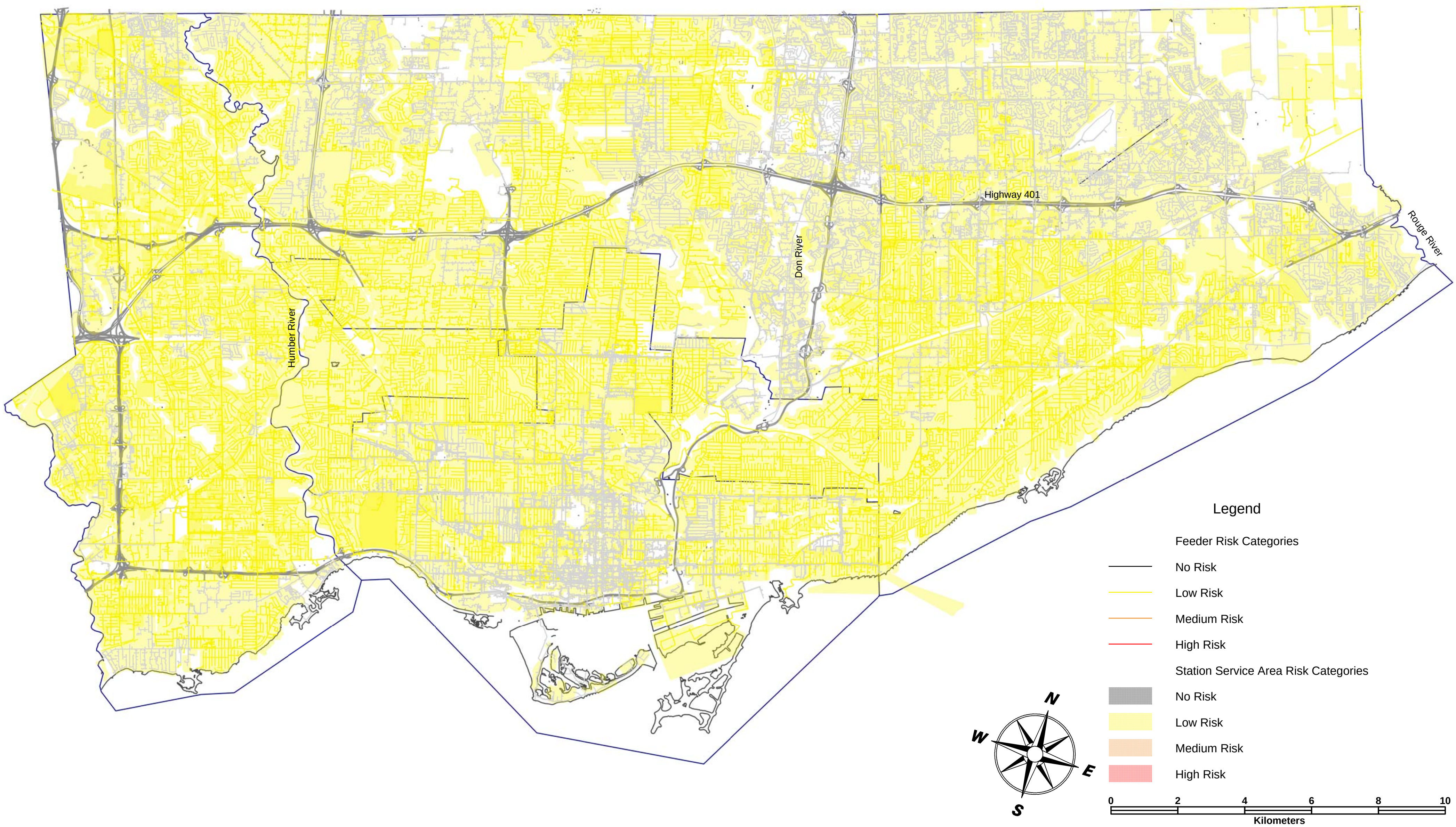
PIEVC Phase 2 Climate Change Risk Map by 2050

14. High Winds Greater Than 120km/h



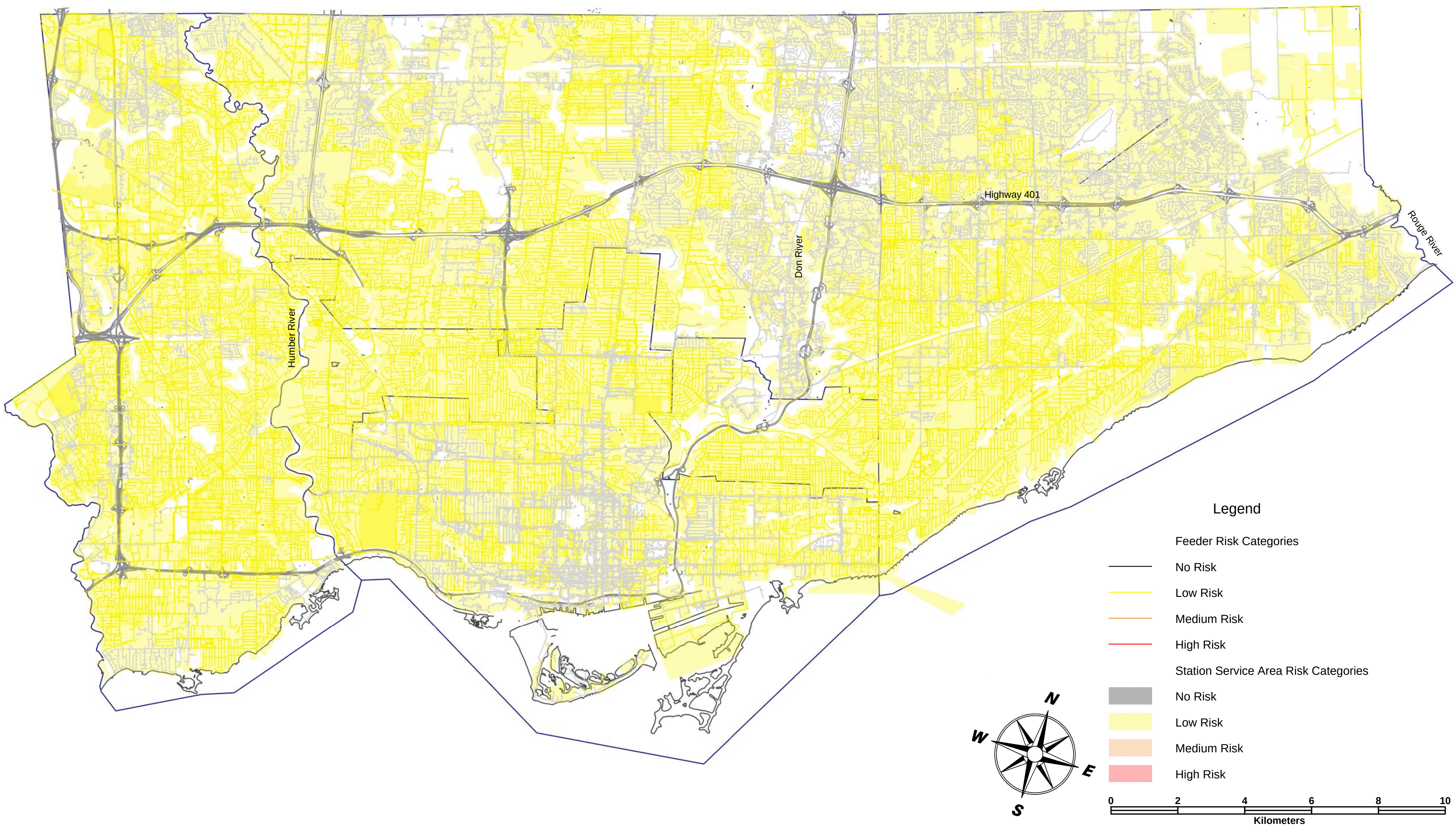
PIEVC Phase 2 Climate Change Risk Map by 2050

15. Tornadoes EF1+



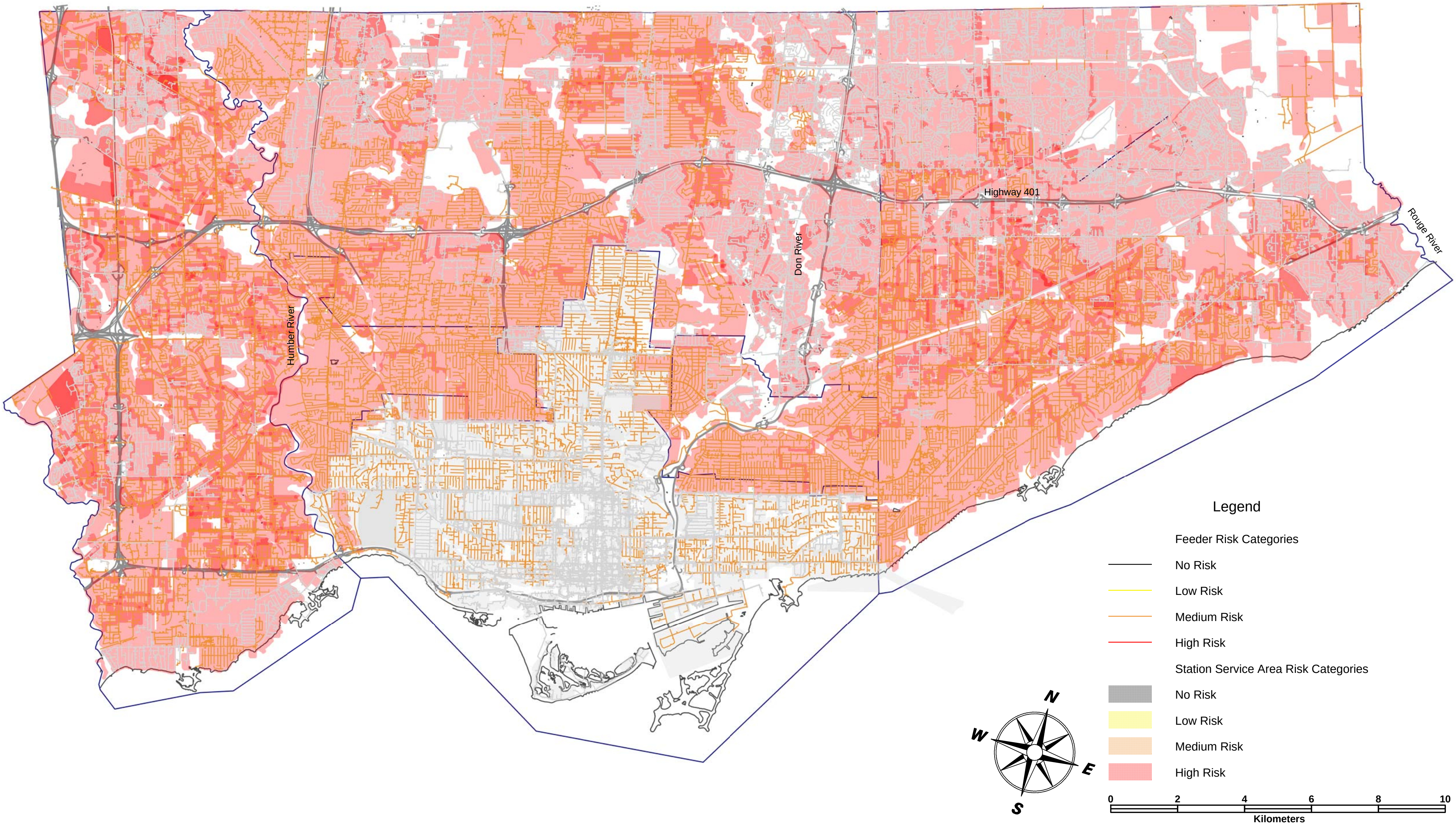
PIEVC Phase 2 Climate Change Risk Map by 2050

16. Tornadoes EF2+



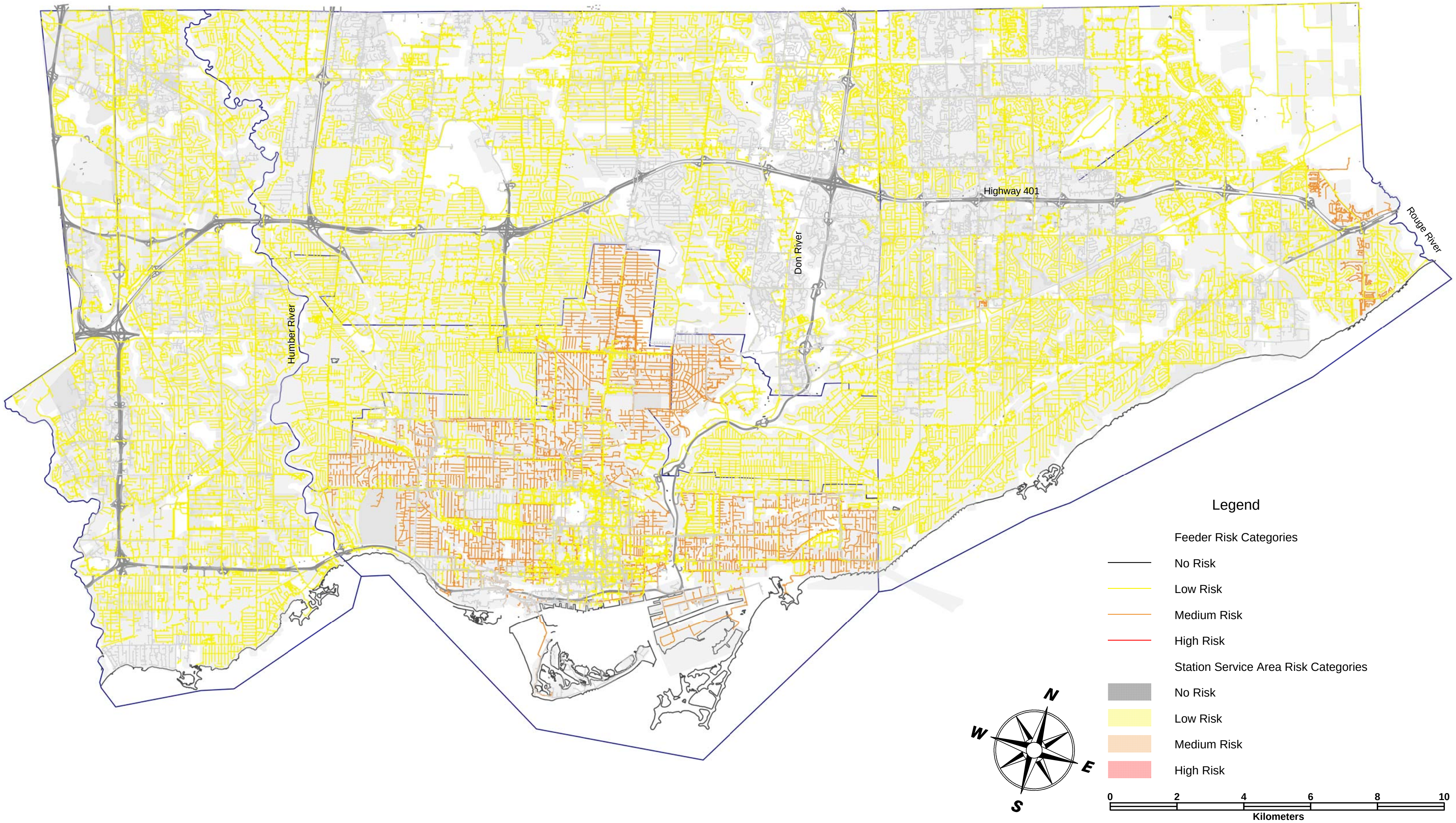
PIEVC Phase 2 Climate Change Risk Map by 2050

17. Lightning



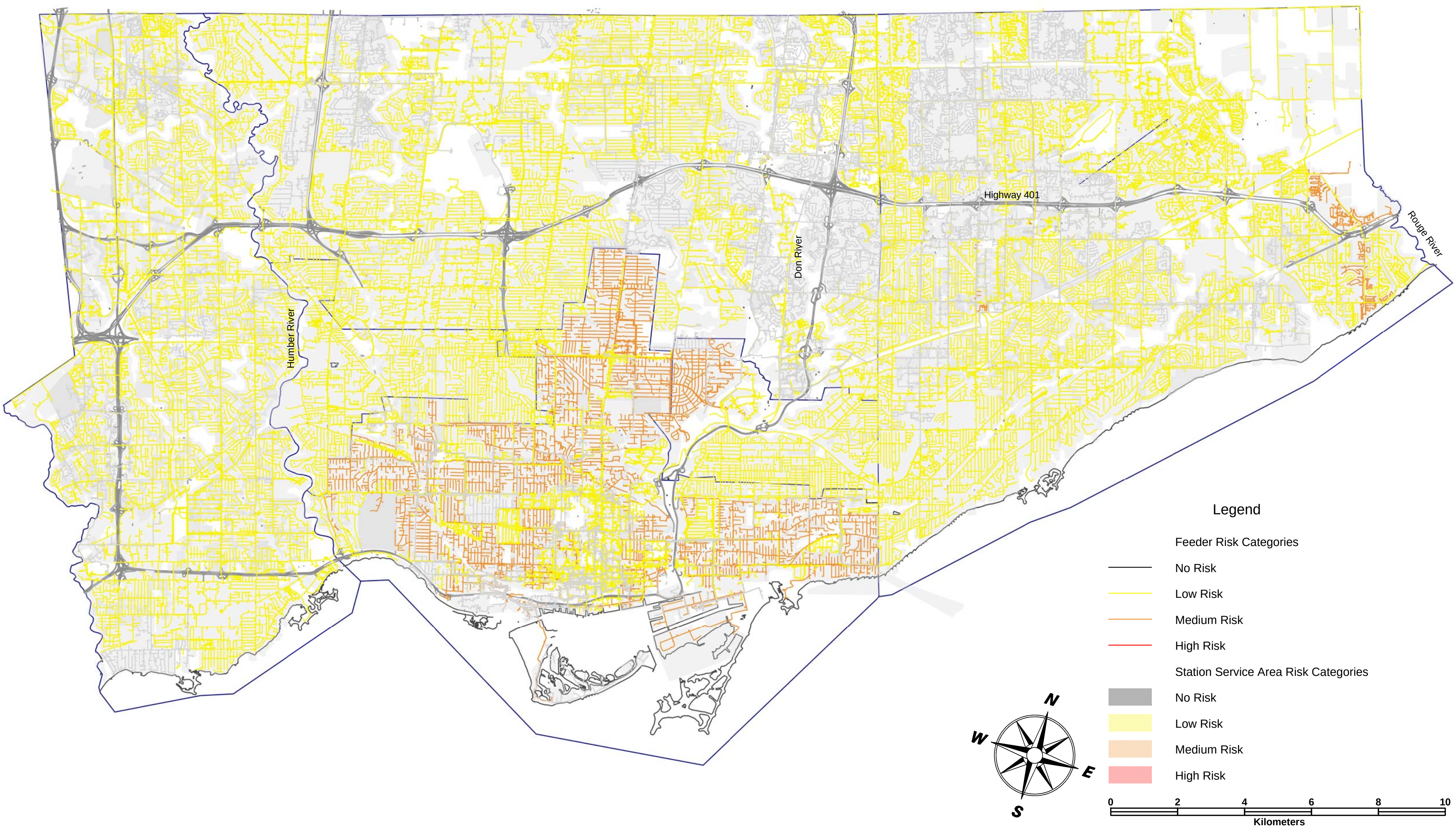
PIEVC Phase 2 Climate Change Risk Map by 2050

18. Snow >5cm



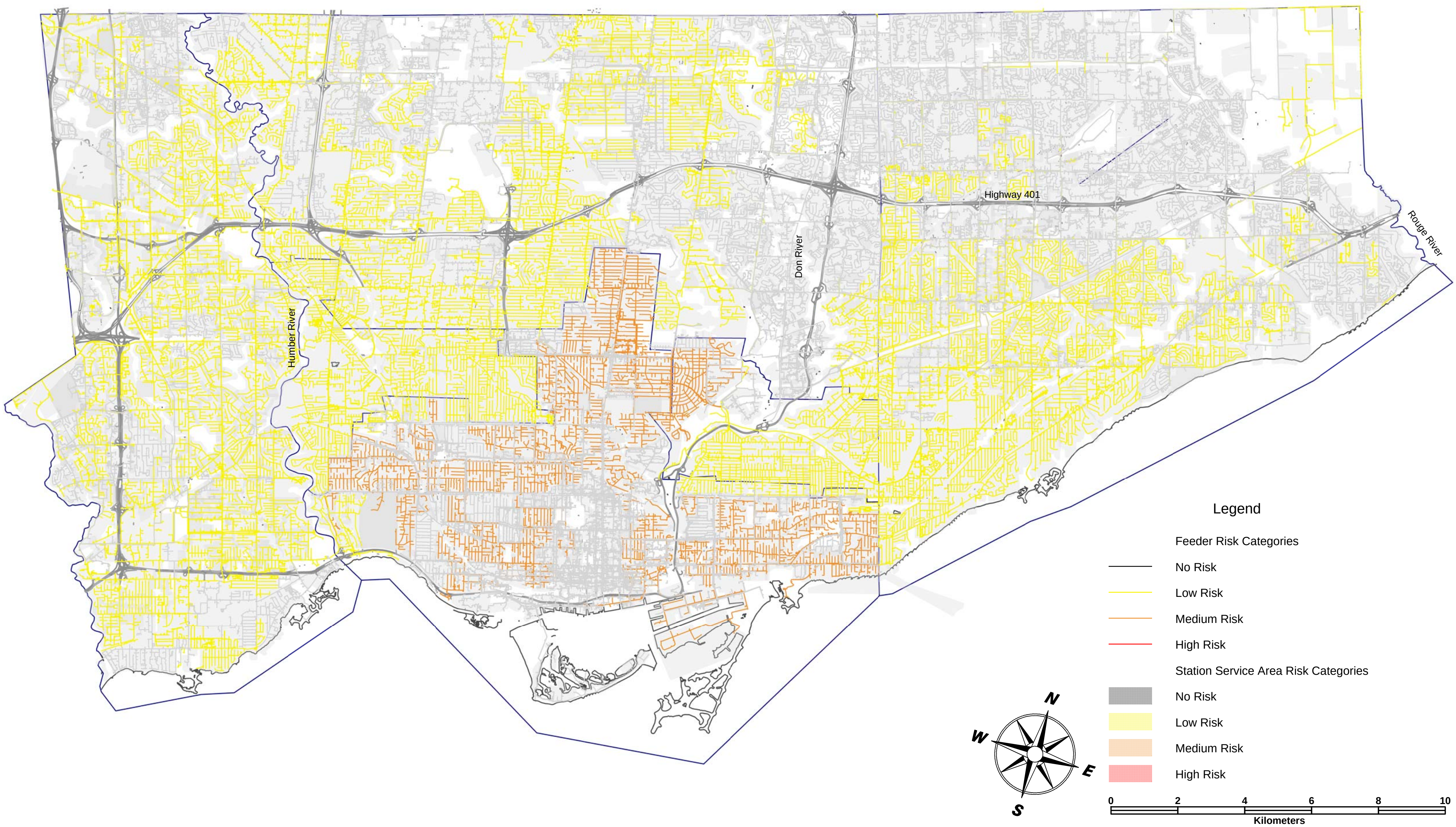
PIEVC Phase 2 Climate Change Risk Map by 2050

19. Snow >10cm



PIEVC Phase 2 Climate Change Risk Map by 2050

20. Extreme Cold Weather



Appendix F
Load Projection Methodology – Toronto Hydro

This information has been removed from the public version of this report

Appendix G
Engineering Analysis

Worksheet 4

The following appendix provides details about the estimation and calculation of the various load and capacity factors used in the Engineering Assessment of medium risk climate/infrastructure interactions. AECOM has elected to present this material in the following section in lieu of worksheet 4 template of the PIEVC Protocol.

1.1 Engineering Analysis Method

The engineering analysis is presented according to the following structure:

1. # Climate parameter / infrastructure system or component

Results and consequences: a recapitulation of the risk scoring results (scores range from 1 to 49) and consequences from Protocol Step 3, risk assessment activity

Task 1: Total Load: The total projected load, L_T, is the sum of three load parameters, $L_E + L_C + L_O$
- L_E = Existing load.
- L_C = Changing climate load placed on the infrastructure components for the project time horizon (2030 – 2050).
- L_o = Other projected change loads.

Task 2: Capacity: The total projected capacity, C_T is the sum of three parameters, $C_E - C_{\Delta E} + C_A$
- C_E = Existing capacity.
- $C_{\Delta E}$ = Projected change (loss) in capacity arising from aging and normal wear and tear of the infrastructure components
- C_A = Other projected additional capacity

Task 3: Vulnerability ratio: When possible, the vulnerability ratio is calculated

$$V_R = \frac{L_T}{C_T}$$

→ When $V_R > 1$, the infrastructure component is vulnerable

→ When $V_R < 1$, the infrastructure component has adaptive capacity

Task 4: Capacity Deficit: When the infrastructure is considered vulnerable, the projected capacity deficit, C_D is calculated, where possible. $C_D = L_T – C_T = L_T – (C_E + C_{\Delta E} + C_A)$

Task 5: Conclusions from the Engineering Analysis: A statement is made as to whether the climate parameter-infrastructure interaction should be passed to Step 5 of the Protocol (i.e. making a recommendation to mitigate a vulnerability) or need not be considered further due to resilience to climate change.

When the engineering analysis cannot be completed, data gaps and possible types of additional studies are described that would facilitate the assessment of infrastructure vulnerability.

1.2 Resiliency or Vulnerability Evaluation

1. High temperature above 25°C and above 30°C / Transmission and Municipal stations and all Temperatures / Protection and Control systems

- **Results and consequences**: Risk scores of 14 and 21 depending on station excess capacity rating. Batteries lifespan is reduced. They are vital components because they are used as back-up power in case of power outages and emergencies and supplied DC current to many equipment in the stations.

- **Load**

L_E = Continuous loads (e.g. lighting) + Noncontinuous loads (e.g. fire protection systems) + Momentary loads (e.g. switchgear operations). A margin of 10-15% can be applied by the designer. Also the battery's rated capacity should be at least 125% (1.25 aging factor) of the load expected of its service life (IEEE-Std-485, 1997).

L_C: Same loads will apply. Ventilation may be a little bit higher because of higher temperatures but the load will not change drastically.

L_o: No other load to consider

$L_T = L_E + L_C + L_O = L_E + xL_E + 0$, where x is very small. Approximation: $L_T = L_E$

- **Capacity**

C_E: The batteries are designed to operate at a temperature of 25°C. They are not installed in a temperature controlled room.

C_E capacity at 25°C = 100%. Expected service life = 25 years
The end of life of a battery is considered to be at 80% of its capacity (IEEE 485).

$C_{\Delta E}$: Battery capacity at higher temperatures will actually increase if the cells are designed for a capacity of 100% at 25°C. From IEEE (IEEE-Std-485, 1997), "If the lowest expected electrolyte temperature is above 25 °C (77 °F), it is a conservative practice to select a cell size to match the required capacity at the standard temperature and to recognize the resulting increase in available capacity as part of the overall design margin". However, sustained high ambient temperatures result in reduced battery lifetimes.

$C_{\Delta E}$ capacity over 25°C: more than 100%. Expected Service life will be less than 25 years. From Toronto Hydro's experience, some batteries have only lasted 10 years when they were expected to last 25 years.

C_A: Battery designs are maintained at 100% capacity at 25°C.

$C_T = C_E - C_{\Delta E} + C_A = C_E - (-xC_E) + 0 = (1+x)\,C_E$, but expected lifetime decrease.

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{(1+x)Ce} < 1 \; but\ life\ expenctancy\ decrease$$

- **Conclusion: Yes. Further action recommended.** Under higher temperatures, batteries will continue to be able to supply the necessary power to operate equipment (e.g. lighting, fire protection systems, switchgears). However, battery life may continue to be shorter than expected. Toronto Hydro has already encountered this problem, as batteries with a lifespan of 25 years are being replaced after 10 years.

2. High temperature above 35°C / Transmission stations

- **Results and consequences**: Risk scores of 21 and 28 depending of station excess capacity rating. Power transformers may be overloaded.

- **Load**

L_E = Maximum coincident load (year of design) + % of contingency at ambient temperature of 30°C
The actual peak load of the area is around 5 000 MVA.

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

C_E: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity at 30°C average ambient, and hottest point within power transformers not exceeding 110 °C. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).
Toronto Area transmission stations installed capacity is around 7 550 MVA.

$C_{\Delta E}$: x%, where x is less than 100. According to IEEE (IEEE-Std_C57.91, 2012) the associated maximum air temperature should not be more than 10°C above the average ambient air temperature for air-cooled transformers (40°C). Station capacity at higher temperatures (e.g. 35°C) will be lower than at design temperature (30°C ambient) because the hottest point within power transformers has to be maintained below 110°C. Same expected service life if the load is adjusted (i.e. decreased) to meet these temperature restrictions. There x% at maximum temperatures above 35°C will not be large.

C_A: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The added capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “moderate” and “low” ratings mean stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + 0 = (1 - x)\, C_E}$ **= Approximation** $\mathbf{C_T \approx C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

- **Capacity deficit**

$\mathbf{C_D = L_T - C_T = (1 + a + b)\, L_E - (1\text{-}x)\, C_E.}$

The capacity deficit can’t be calculated because the load growth rate for the study period is not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. This could be calculated in further studies. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C apply to this interaction.

3. High temperature above 40°C and Average temperature > 30°C / Transmission stations

- **Results and consequences**: risk score of 35 for transmission stations which have good future capacity (excess capacity) in the Horseshoe Area. Transmission stations with low future capacity ratings scored a high risk. Power transformers will be overloaded.

- **Vulnerability Ratio:** Refer to parameter #2.

- **Conclusion: Further action recommended**. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and High nighttime temperatures (+23°C) / Transmission stations

- **Results and consequences**: risk rating of 21, 28 and 35 depending of station capacity rating by 2050. Power transformers may be overloaded.

- **Load**

$\mathbf{L_E}$ = Maximum coincident Load (year of design) + % of contingency at ambient temperature of 30°C

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase caused to higher consumption of clients = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Power transformers can operate at temperature above 30°C, but long periods of high temperature can affect the equipment, such as when night time temperatures are high. The power transformer has no time to cool.

$\mathbf{C_A}$: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The future capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “low” rating means stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + 0 = (1 - x)\, C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{(1-x)Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{(1-x)7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

Value of (1-x) = The loss of capacity is highly variable. It will not only depend of the maximum temperatures but also of the minimum temperatures. If the minimum temperature stays high during many days the power transformers will have no time to cool and its capacity will have to be reduced. High nighttime is important in that sense.

- **Capacity deficit**

$\mathbf{C_D = L_T - C_T = (1 + a + b)\ L_E - (1\text{-}x)\ C_E.}$

The capacity deficit cannot be calculated because the load growth and the loss of capacity are not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Consecutive days with high temperatures and high night time will increase over the study period. For example, high nighttime temperatures will go from 0.7 day/year to 7 days/year in 2030 to 16 days/year in 2050. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature>30°C are also relevant to the heat wave and high nighttime temperature parameters. A load growth rate could be calculated for a better evaluation of impacts.

5. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Transmission stations and Municipal stations

- **Results and consequences**: risk rating 28
  Outgoing lines (overhead) could fall down

- **Load**

$\mathbf{L_E}$ = Actual load is equal to the actual number of days of freezing rain

$\mathbf{L_C}$ = The load due to the freezing rain will slightly increase, $\mathbf{L_C}$ = a$\mathbf{L_E}$**,** where ''a'' is a % of increase (small)

$\mathbf{L_o}$ = N/A

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E}$

- **Capacity**

$\mathbf{C_E}$: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called “Heavy Loading” specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$\mathbf{C_{\Delta E}}$: It is assumed that the capacity will remain the same if the design criteria are not changing. $\mathbf{C_{\Delta E}}$ = **0**

$\mathbf{C_A}$: N/A

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E}$

- **Vulnerability Ratio**

$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$, the infrastructure is vulnerable

- **Capacity deficit**

$\mathbf{C_D = L_T - C_T = (1 + a)\ L_E - C_E.}$

- **Conclusion: Further action recommended.** The probability of occurrence of a heavy freezing rain event of 60 mm is relatively low in the future (8 – 25% probability of occurrence over the 35 year study period). However, this this interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events (design capacity). Therefore, solutions for 25 mm events also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / Municipal stations

- **Results and consequences**: 21, 28, 35. Medium to high medium risks.
  Consequences: Power transformers may overload.

- **Load & Capacity:** Same assumptions as for the power transformers in the transmission stations.
  The load will increase because of warmer temperatures. The capacity will decrease because of power transformers low ability to withstand hot temperatures for extended periods.
  Added capacity: Many Toronto Hydro to Toronto Hydro stations which interconnect the 4.16 kV power lines, will progressively be replaced by converted lines at 13.8 kV. Most of the municipal stations will then be to interconnect voltage levels from 27.6 kV to 13.8 kV. It is assumed that added capacity during the study period will be low for the 27.6-13.8 kV / 4.16 kV stations. More capacity can be added to the 27.6 kV/13.8 kV stations and will be variable depending on the stations need.
  For Toronto Hydro to Private owner ship, added capacity is possible and will be very variable depending on Client's need.

  $L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$
  $C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + yC_A$ where x is variable and y is small and variable$\rightarrow C_T < C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{\mathrm{CE} - (\mathrm{xCE}) + \mathrm{yCA}} < 1$$

- **Conclusion: Further action recommended**. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and the cables. For Toronto Hydro to Private ownership stations, a case by case evaluation is recommended.

1.2.1 Underground and Overhead feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / Underground feeders

- **Results and consequences**: risk ratings 14, 21 and 28. The high demand stresses cables and power transformers. More capacity was available in the horseshoe area giving slightly lower results.

- **Load**

$\mathbf{L_E}$ = Actual demand + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of higher electrical consumption of clients (more electronic devices) = bL_E

$\mathbf{L_T = L_E + L_C + L_O}$

- **Capacity**

$\mathbf{C_E}$: Actual design of cables and power transformers is based on the actual load plus a margin. For underground feeders in the dual radial system, feeder capacity equals 50% of load for two parallel feeders. IEC 60287 base maximum ambient temperature at 35°C and maximum ground temperature at 20°C (IEC-60287))

$\mathbf{C_{\Delta E}}$: XLPE cables have an expected life of 40 years (for concrete duct installations) and for PILC cables 75 years. These cables are today reaching their expected life because they were installed during the early 1900s (for PILC) and 1950s (for XLPE). They will be changed through testing or from failure, because even if the cables are old they could be still being in good conditions (Toronto Hydro - OM&A, 2014). However, with climate changes (higher temperature), these cables will be stressed more often. Aging processes will accelerate and reduce capacity. This is a highly variable factor and cannot easily be calculated.

C_A: Added capacity will be done by Toronto Hydro. Underground planning group could estimate the projected capacity for the study period.

$C_T = C_E - C_{\Delta E}$? $+ C_A$

- **Conclusion: Further action recommended.** The vulnerability ratio and the capacity deficit cannot be calculated because the projected load on cables is not known. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / Underground feeders

- **Results and consequences**: risk rating of 12, 18, 24, 30
  a. Feeders: Water treeing of the cables, flooding (18-24);
  b. Nun-submersible equipment failure in vault type stations below ground (30 Horseshoe Area, 36 Former Toronto);
  c. Above ground stations, access could be limited (12);
  d. Network feeders: old N/W protectors are not submersible (30).

a. Feeders: Water treeing of the cables, flooding (18 Horseshoe Area, 24 Former Toronto)

Water treeing refers to a partially conductive structure that may form, in the presence of water, within the polyethylene dielectric used in buried high voltage cables. […] Water trees begin as a microscopic region near a defect. They then grow under the continued presence of a high electrical field and water. Water trees may eventually grow to the point where they bridge the outer ground layer to the center high voltage conductor, leading to complete electrical failure at that point (Wikipedia).

- **Load**

L_E = Actual demand + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase due to higher electrical consumption by clients (more electronic devices)= bL_E

$L_T = L_E + L_C + L_O$

- **Capacity**

C_E: Actual design of cables is based on the actual load plus margin. For the underground feeders in the dual radial systems, each feeder capacity is equal to the load x 2.

$C_{\Delta E}$: Flooding and heavy soil moisture tends to reduce the dielectric strength of cables. This cannot be calculated as it is highly variable. *The aging mechanism of underground cables depends on factors that involve the cable characteristics, accessory characteristics, and operating conditions, different power cable systems will age in different ways. In fact, aging degradation, and failure mechanisms are statistical in nature.* (NEETRAC, 2010)

C_A: Toronto Hydro shall have a planning procedure for increasing the capacity of their underground system in line with load growth.

- **Conclusion: Further action recommended.** The load can be calculated by Toronto Hydro's estimates. However, the capacity is very hard to define, as aging degradation depends on many factors. Nonetheless, in combination with high heat events, extreme rainfall impacts on underground cables was deemed a vulnerability.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (30) (Former Toronto has a high risk result)

- **Load**

L_E = 0.04 flood per year (over 100 mm + short duration).

L_C = 0, flood intensity is considered to be the same for a given event (100 mm rainfall), but it will occur with greater frequency. Another complicating factor is how local drainage conditions (area topography, sewer system changes, land use changes) may or may not change flood characteristics in below ground vaults. At the scale of the current study, site specific flooding characteristics are not considered.

L_o = N/A

$L_T = L_E + L_C + L_O$ = L_E.

- **Capacity**

C_E: Cannot work when flooded. Most of the vaults have pumps when they are deeper than the city sewers. Small shallow single phase vaults drain naturally to the sewers. Pumps usually work well. There is no specific information available on the capacity of the pumps, but they are assumed to function correctly, as there are no indications that pump capacity needs to increase.

$C_{\Delta E}$: same as today. $C_{\Delta E} = C_{E1} - C_{E2} = 0$.

C_A: No additional capacity required.

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{Ce} = 1$$

Conclusion: Further action recommended. Without replacement of non-submersible equipment by submersible equipment, the performance of electrical equipment in below grade vaults will not change over time (i.e. non-functional when flooded) The planned conversion of non-submersible equipment to submersible types in flood prone areas will help reduce vulnerability. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period, and hence remain a vulnerability for Toronto Hydro.

c. Above ground stations, access to the station and to the station equipment could be limited due to localized flooding of streets around the station, or at the station itself

- **Results and consequences** Low –medium risk.

- **Conclusion: No further action required.** This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible (30)

- **Conclusion: Additional Study Recommended.** The old N/W protector may not operate properly if flooded. A network protector automatically connects and disconnects its power transformer from the network when the protector relay detects that power starts flowing in a reverse direction, preventing back feed, which is a potential safety hazard. However a failure of the N/W protector will not mean an interruption to the customer, since network systems are highly redundant. Network protectors are overhauled on a three-year cycle.

  Installations of new N/W protectors are submersible but there are still many old N/W protectors in the systems, particularly in downtown. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and impact of old N/W protectors being flooded.

9. High winds (120 km/h) / Padmount stations on distribution network (Former Toronto)

- **Results and consequences**: risk rating 14. Flying debris could impact the equipment.

- **Vulnerability Ratio:** The consequence of high winds and structural loads from flying debris are difficult to establish in terms of the load and the capacity of padmount stations. It's an independent impact based on a statistical probability.

- **Conclusion: No further action required.** The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

- **Results and consequences**: risk ratings of 14, 21, 28, 35
  These 4 climate parameters have the same consequences: Overload of the ONAN power transformers and the overhead conductors.

- **Load**

$\mathbf{L_E}$ = Max load + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of load growth due to population growth = bL_E

$$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$$

- **Capacity (ONAN power transformers)**

$\mathbf{C_E}$: 100% at 30°C average ambient + hottest point within transformer not exceeding 110 °C.

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Capacity at higher temperature will decrease, because the hottest point has to be kept under 110°C.[1]

$\mathbf{C_A}$: Additional capacity can be added by adding more power transformers on the lines.

$$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A}$$

- **Capacity (overhead conductors)**

[1] For example: temperature of 40°C during 10 hours, the average load should not excess 80-85% of the nominal kVA.

C_E: 100% at 75°C for ACSR conductors and 25°C ambient (manufacturers' limits).
Effects of high temperature can results in the annealing[2] of aluminum used within ACSR and AAC conductors. This effect begins at 93°C for these types of conductors, and is a function of the magnitude of the temperature and the duration of the application (electrical power flow).

$C_{\Delta E}$: x%, where x is lower than 100. The added combination of high temperature and higher current flow will significantly reduce the capacity of the conductors.
Other impacts: loss of strength due to annealing, increase in sag.

C_A: Capacity can be added by using other or larger types of conductors. However, in some place it could be difficult to do so as it would means to redesign the existing lines and may result, for example, in the replacement of existing poles by stronger ones generating high costs.

$$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E - (xC_E) + C_A = (1 - x)\, C_E + C_A.}$$

The reduction of the capacity is difficult to calculate because of the great diversity of operating circumstances and loading of the entire system. However, calculations for critical areas, where added capacity can be difficult to do, should be done.

- **Vulnerability Ratio:** Cannot be calculated because too many variables are not known.

- **Conclusion: Further action recommended.** Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zone) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

- **Results and consequences:** risk rating 14
  Overload of the ONAN power transformers

- **Load and Capacity:**
  Refer to the previous evaluation. However, the capacity of the power transformers will not be reduced as much as for higher daily maximum temperature. Therefore, $C_E = xC_E$, with x as a small value.

  High nighttime temperatures have consequences on the capacity of the power transformer to cool enough before being loaded the next day. Climate projections show a significant increase in the number of days with low night time temperatures ≥ 23°C. The actual design of power transformers can support this temperature limit. As such, this impact was judged as low.

- **Conclusion: No further action required.** Night time temperatures with minimum ≥ 23°C will not have big impacts on the delivery of electricity. However, it is important to note that combination events of high daily temperature and high night time temperature are a concern. This is taken into account under the parameter, average temperature over 30°C on a 24 h basis.

12. Freezing Rain - Ice Storm 15 mm and high winds 70 km/h / Overhead Feeders in Loop Configuration

- **Results and consequences**: risk ratings of 28, 35 Conductors (tree contacts).

- **Load:**

[2] Annealing is the metallurgical process where applied temperature softens hardened metal resulting in loss of strength. For overhead conductors, annealing can degrade the strength of aluminum wires used in ACSR and AAC conductors (PJM Overhead conductor Ad Hoc Committee, 2010)

L_E = the actual load is based on tree branches that usually start to break with a 15 mm of freezing rain.

L_C = freezing rain of 15 mm will happen a little bit more often for the study period (from 0.11/year to 0.12/year to 0.16/year). Hypothesis $L_C = L_E$

L_o = N/A

$L_T = L_E + L_C + L_O = L_E$.

- **Capacity :**

C_E: Actual overall ''capacity'' of the tree canopy in Toronto.

$C_{\Delta E}$: $C_{\Delta E} = C_{future} < C_E$. The future overall ''capacity'' will decrease (or vulnerability to damage will increase) because of new or exacerbated disease and pest conditions and possibly, because of the tree faster growth (extended growing season, more branches).

C_A: N/A

$C_T = C_E - C_{\Delta E}$

- **Vulnerability Ratio**
  - $VR = \frac{Lt}{Ct} = \frac{Le}{Ce - C\Delta E}, where\ \frac{Le}{Ce} = 1, as\ Ce - C\Delta E$ is smaller, V_R will be >1

- **Capacity deficit**

$C_D = L_T - C_T$ = It cannot be calculated because the future capacity of the trees is not known.

- **Conclusion: Further action recommended.** The risk assessment completed in step 3 for radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, freezing rain events are expected to occur slightly more often than it does currently by the end of the study horizon. The tree canopy may also be affected by new or increased disease threats and extended growing season. Conductors will also sag more due to more extreme weather (ice, warm weather, etc.) leading to more contacts with the tree branches. According to THESL (Toronto Hydro - OM&A 2014): "*Vegetation interference is one of the most common causes of power interruption*". Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Overhead lines (radial and loop)

- **Results and consequences**: risk rating 24, 28
  Overhead lines could fall down, salt contamination

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, $L_C = aL_E$, where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called “Heavy Loading” specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. **$C_{\Delta E} = 0$**

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T - C_T = (1 + a)\, L_E - C_E$.

- **Conclusion: Further action recommended.** See explanation for freezing rain and stations (item 5 above).

14. Lightning / Overhead power lines (radial and open loop) and SCADA system

- **Results and consequences**: risk rating of 18, 24, 30, failure of equipment (localized).

- **Vulnerability Ratio:** In this case, the impact comes from a direct or indirect strikes and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: Further action recommended.** It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, the number of arrestors/km, lightning strike intensity and arrestor performance are not monitored by Toronto Hydro. In the absence of this information, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability. Further studies could evaluate if the actual protection of overhead power lines is sufficient, or if investments for more protection needs to be made. Direct strike impacts can be studied with software (e.g EMTP), while indirect strikes can be calculated numerically.

15. Snow > 5 cm and Snow > 10 cm / Overhead power lines (radial)

- **Results and consequences**: risk ratings of 14, salt deposited on the roads can also accumulate on insulators from water evaporation and transport through the air, and can create a failure (reduce the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires or switch with porcelain insulator failure).

- **Vulnerability Ratio:** In that case, the impact is indirect and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: No further action required.** The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue. From THESL’s report (Toronto Hydro - OM&A 2014): *to mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year.* Furthermore, recall that porcelain insulators are being progressively replaced by polymer insulators. *Polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. […] Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. […] Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking […] posing a safety risk to employees or members of the public below.* As older porcelain insulators are being replaced by polymer insulators, it was judged that no further action than what is currently underway is required.

1.2.2 Civil structures

16. Extreme Rainfall, Freezing rain/Ice storm 15 mm & 25 mm & 60 mm (Combination of events) / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk rating of 12, 14
  Accelerated corrosion of reinforcing bars and degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Currently, civil structures (cable chambers, vaults) degrade at a pace related to the actual load (salt and moisture) related to current weather: Extreme Rainfall (100 mm) 0.04/year + Ice Storm (15 mm) 0.11/year + Ice Storm (25 mm) 0.06/year + Ice Storm (6hrs+) 0.65/year.

L_C = In the future, the structures will degrade more rapidly due to the more severe weather:
2030: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.12/year + Ice Storm (25 mm) 0.07/year + Ice Storm (6hrs+) 0.73/year.
2050: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.16/year + Ice Storm (25 mm) 0.09/year + Ice Storm (6hrs+) 0.94/year.

L_o: No other load.

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults are getting older, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life (Toronto Hydro - OM&A, 2014).

For the purpose of the study, we can then assume that $C_{\Delta E} = aC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ $= (1-a)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{(1-a)Ce} > 1$$, the infrastructure component is vulnerable

- **Conclusion: Further action recommended.** Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro - OM&A 2014): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and* *corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below*-grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability.

17. Snow > 5 cm and Snow > 10 cm / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk ratings of 14, 21, Degradation of concrete in cable chambers and vaults.

- **Load**

$\mathbf{L_E}$ = Actually the civil structures (cable chambers, vaults) degrade at a rhythm caused by current climate.

$\mathbf{L_C}$ = The ''load'' will probably decrease. $-aL_E$

$\mathbf{L_o}$ = No other load.

$\mathbf{L_T = L_E + L_C + L_O = L_E - aL_E = (1\text{-}a)L_E}$

- **Capacity**

$\mathbf{C_E}$: actual capacity based on design criteria

$\mathbf{C_{\Delta E}}$: As vaults age, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life, (Toronto Hydro - OM&A, 2014)).

For the purpose of the study, we can then assume that $C_{\Delta E} = bC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

$\mathbf{C_A}$: N/A

$\mathbf{C_T = C_E - C_{\Delta E} + C_A} = (1\text{-}b)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1-a)Le}{(1-b)Ce}$$, it is not possible to know if a will be < or > b

- **Conclusion: No further action required, but combinations of climates events require additional study.** As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / Civil structures (overhead and underground feeders)

- **Results and consequences**: risk rating of 14, frost heave of civil structures

- **Vulnerability Ratio:** In the future, the ''load'' will reduced as less frost days are expected. However, as vaults and as the foundations for concrete or steel poles age, the capacity of the structures will decrease.

  Conclusion: Further action recommended. Even if the frost threat is decreasing, it is noted that frost penetration will still occur during the study period with occasionally extreme weather. Since, Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts were judged to be a vulnerability.

19. All Climate Parameters / Human Resources

- **Results and consequences:** risk ratings of 14 to 28, weather related impacts on safe site access, work conditions and travel

- **Conclusion: Further action recommended.** While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

Appendix H
PIEVC Worksheets

Worksheet 1 and 2 have been removed from the public version of this report.

However, information on infrastructure can be found in summary form in Chapter 2 of this report. Climate information can be found in Chapter 3, and in Appendix B and Appendix C of this report.

Worksheet 3 information can be found in Appendix D.

Worksheet 4 information can be found in Appendix G.

Worksheet 5 information is contained within Chapter 7 of this report.

D3 Asset Lifecycle Optimization

Exhibit 2B, Section D1 provided an end-to-end overview of Toronto Hydro's distribution system Asset Management System ("AMS"), from strategic planning, to execution and reporting, including the translation of corporate and stakeholder requirements into asset performance and asset management capability objectives. Section D2 provided an overview of the current state of the major distribution assets that the utility manages based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area. Section D3 focuses on key factors that guide and influence investment pacing and prioritization decisions within the AM Process.

- **Section D3.1** provides an overview of the replacement, refurbishment, and maintenance approaches that Toronto Hydro applies to major asset classes to optimize the value derived from individual assets over their lifecycles. These asset lifecycle optimization practices are the fundamental building blocks for asset management and investment planning at Toronto Hydro;
- **Section D3.2** describes the ways in which the utility considers and manages failure risk in its AMS. Risk management takes various qualitative and quantitative forms and is fundamental to deriving expenditure plans that support the optimization of future outcomes within a constrained budget;
- **Section D3.3** describes the ways in which the utility considers and manages capacity risk in its AMS; and
- **Section D3.4** describes the expenditure program planning process that Toronto Hydro uses to derive a capital expenditure plan from its AMS.

For an overview of how the practices discussed in this section informed Toronto Hydro's 2025-2029 Capital Expenditure Plan for system-related investments, see Exhibit 2B, Section E2.2.

D3.1 Asset Lifecycle Optimization Practices

As noted in Exhibit 2B, Section D1, the broad objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. At the most fundamental level, this value is realized by consistently implementing prudent lifecycle optimization practices tailored to specific asset classes. These practices serve as guidelines for when and how to inspect and intervene on a specific asset, where intervention includes asset maintenance, refurbishment, and replacement.

Toronto Hydro's lifecycle optimization practices are the result of decades of experience managing major distribution assets across a dense, mature, and congested major city that is served by various system designs and configurations. These practices consider the various attributes of an asset class, including, but not limited to: (i) the intended functionality of the asset in the distribution system and the various modes of deterioration and failure over the asset's typical lifespan; (ii) the potential impact of various failure modes on distribution service; and (iii) the typical costs and customer impacts of intervention.

As discussed in Section D1, Toronto Hydro is committed to continuous improvement in asset management, and is pursuing certification under the internationally recognized ISO 55001 standard for Asset Management in the 2025-2029 period. The utility expects that the journey toward certification will involve additional improvements and refinements to its asset lifecycle optimization practices, including more comprehensive documentation and governance of said practices and associated processes and decision-making tools.

The following two sub-sections describe Toronto Hydro's asset lifecycle optimization practices, beginning with the utility's foundational maintenance and refurbishment practices, followed by a description of the utility's typical asset replacement practices for major asset classes.

D3.1.1 Maintenance and Refurbishment Practices

As part of its overall asset management process, Toronto Hydro aims to ensure the continuous serviceability (i.e. usefulness) of assets over their typical or expected useful lives, and to extend an asset's serviceability when it is feasible and economical to do so. Asset maintenance and refurbishment practices are the methods by which Toronto Hydro supports these objectives.

D3.1.1.1 Reliability Centered Maintenance

Toronto Hydro typically conducts inspection and maintenance tasks on a fixed cycle, however some tasks are performed on a variable cycle. These activities are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Maintenance activities support the minimization of overall lifecycle costs and account for factors such as the safety of Toronto Hydro employees and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.

Toronto Hydro's foundation for maintenance planning is Reliability Centered Maintenance ("RCM"), an established engineering framework for the maintenance of assets throughout their lifecycles. The RCM framework determines failure management policies for any physical asset in its present operating context to maximize useful life and reliability based on the assets function, and the consequences of functional failure, including the asset's criticality to the distribution system. The output of an RCM analysis includes a failure mode analysis, which is used to identify proactive tasks (with associated time intervals) that help to predict or prevent failures from occurring. It also focuses on preventing failures where consequences are most severe. Toronto Hydro initially adopted an RCM framework in 2003 and subsequently reviewed and updated its outputs in 2011 and over the 2016 and 2017 period, ensuring compliance with the Society of Automotive Engineers ("SAE") standards SAE JA-1011 and SAE JA-1012 which sets outs the minimum characteristics that a process must have in order to be an RCM process and provides guidance on how to meet the requirements of SAE JA-1011, respectively.[1] The resulting analysis produces failure management policies forming part of the maintenance program that are deemed to be the most cost and risk effective at sustaining asset performance in accordance with the company's risk tolerance level.

RCM is a comprehensive approach to the lifecycle maintenance of distribution system assets. Initially developed in the airline industry to manage high maintenance costs and high failure rates, RCM has allowed Toronto Hydro to increase its analytical capabilities in determining the optimal level of maintenance expenditures and the appropriate time of intervention for a specific asset class. The RCM framework incorporates a thorough analysis of assets going beyond manufacturers' requirements to evaluate functional failures under utility-specific operating conditions. The analysis identifies and categorizes consequences of failure (i.e. safety, cost, reliability). Maintenance programs are subsequently set to mitigate these consequences by establishing recommended optimal asset intervention timelines.

The benefits of RCM include:

1) A structured and data-driven targeted maintenance program;
2) Reduced efforts and costs expended on maintenance programs with little resultant value; and
3) Increased reliability due to the effectiveness of the failure prevention program.

[1] Society of Automotive Engineers, SAE JA-1011 (August 2009) and SAE JA-1012 (August 2011).

Toronto Hydro leverages the RCM framework, in combination with the Ontario Energy Board's ("OEB")'s Minimum Inspection Requirements, and the continuous monitoring and assessment of asset performance, to derive its maintenance programs and associated expenditure plans.

As part of developing RCM-based maintenance program expenditure plans, Toronto Hydro continues to seek opportunities for incremental productivity. For example, the utility has standardized the maintenance cycles of overhead switches to align with station maintenance cycles whenever possible to minimize the need for multiple equipment outages and significant switching resources.

The expenditure plans for all planned maintenance programs can be found in Exhibit 4, Tab 2, Schedules 1-3. Table 1 below provides a summary of maintenance practices for the major asset types on each part of Toronto Hydro's distribution system.

Table 1: System Maintenance Practices

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
Overhead	*Pole-top Transformer*	Line Patrols	3 Years Visual, 1 Year Infrared	
	Distribution Poles	Line Patrols	3 Years Visual	
		Wood Pole Inspection & Treatment	10 Years	8 Years
		Concrete & Steel Poles	-	10 Years
	Primary Conductors	Line Patrols	3 Years Visual, 1 Year Infrared	
		Tree Trimming	2-5 Years, with the majority being 3 Years	
	Secondary Conductors	Line Patrols	3 Years Visual	
	Switches	Line Patrols	3 Years Visual, 1 Year Infrared	
		Maintenance (SCADA-Mate & Gang-Operated)	Variable Cycle Greater than 6 Years	6 Years

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Battery Replacement for Switches (SCADA-Mate & Gang-Operated) and Repeater Radio	3 Years	
	Insulators	Insulator Washing (for Porcelain)	6 Months	
Underground	*Padmounted Transformer*	Inspection (Civil + Electrical)	3 Years	
	Submersible Transformer	Vault Inspection (Civil + Electrical)	3 Years	
	CRD Transformer		1 Year	
	URD Transformer			
	Building Vault Transformer	Inspection (Civil + Electrical)	3 Years	
	Padmounted Switch	Inspection (Civil + Electrical)	1 Year	
		Battery Replacement	3 Years	
	Cable Chamber	Cable Chamber	10 Years	
	Cables	Cable Diagnostic Testing	Risk Based	
		Contact Voltage Scanning	1-3 Years	
Network	*Network Transformer*	Network Vault Inspection – Electrical	1 Year	
		Network Vault Inspection – Civil	6 Months	1 Year
		Reverse Power Breaker Overhaul	3 Years	
		Protector Top Cleaning	1 Year	
		Network Protector Overhaul - HV[2]	4 Years	

[2] High Voltage ("HV")

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Network Protector Overhaul - LV[3]	5 Years	
Station	*Station TS & MS (Maintenance & Facilities)*	Monthly Inspections	1 Month	
		Seasonal Detailed Inspection	6 Months	
	Circuit Breaker (All Types) & Switch	Maintenance	4 Years	
	Bus Disconnect Switches			
	B-Bus	B-Bus Cleaning	4 Years	
	Power Transformer	Equipment Maintenance	4 Years	
	DC Battery & Charger	Seasonal Detailed Inspection	6 Months	
	Compressed Air System	Station Compressed Air System Maintenance	6 Months	
	Station Alarms in Downtown	Alarm Testing	1 Year	
	Pilot Wire	Pilot Wire Protection	6 Years	

The proposed changes in cycles for certain asset types are explained below:

- Starting in 2025, Toronto Hydro will be adjusting the inspection cycle for wood poles from ten to eight years in order to better manage the growing volume of wood poles past their useful life, and in HI4 and HI5 condition based on the ACA. This adjustment will also allow Toronto Hydro to better inform its wood pole ACA and support planning of system renewal investments with more timely inspection data of poles in poor condition.
- In 2025, Toronto Hydro will begin to inspect concrete and steel poles as part of its dedicated pole inspection program on a ten-year cycle. Inspections of these poles are supported by the

[3] Low Voltage ("LV")

CSA Standard C22.3, are expected to reduce burden on reactive capital, and will allow Toronto Hydro to improve decisions on planned renewal investments for these assets.

- Due to resourcing and operational constraints, Toronto Hydro has historically found achieving the four-year maintenance cycle of overhead switches noted in its 2020-2024 DSP to be challenging, instead attaining variable cycles generally greater than six years. Beginning in 2025, Toronto Hydro will be maintaining overhead switches on a six-year inspection cycle at a minimum, an approach that is supported by an independent study of Toronto Hydro's overhead switch maintenance practices.
- As of 2027, Toronto Hydro's network vaults will have sensors providing remote monitoring and control, which will allow the utility to reduce the number of on- site inspections, yielding cost savings from the adjustments of maintenance cycles from six months to one year.

D3.1.1.2 Summary of Maintenance Programs and Activities

Asset maintenance programs (Exhibit 4, Tab 2, Schedules 1-5) are grouped into four major categories based on their functionality, as shown below:

- Preventative Maintenance;
- Predictive Maintenance;
- Emergency Maintenance; and
- Corrective Maintenance.

The framework of preventative and predictive maintenance programs is driven primarily by regulatory requirements, as mandated by the OEB's Distribution System Code Minimum Inspection Requirements.[4]

Capturing Asset Deficiencies

The details of how the asset inspections and capital and maintenance programs are related are summarized below as part of the deficiency capturing process in Figure 1.

[4] Ontario Energy Board, Distribution System Code, (August 2, 2023), Appendix C.

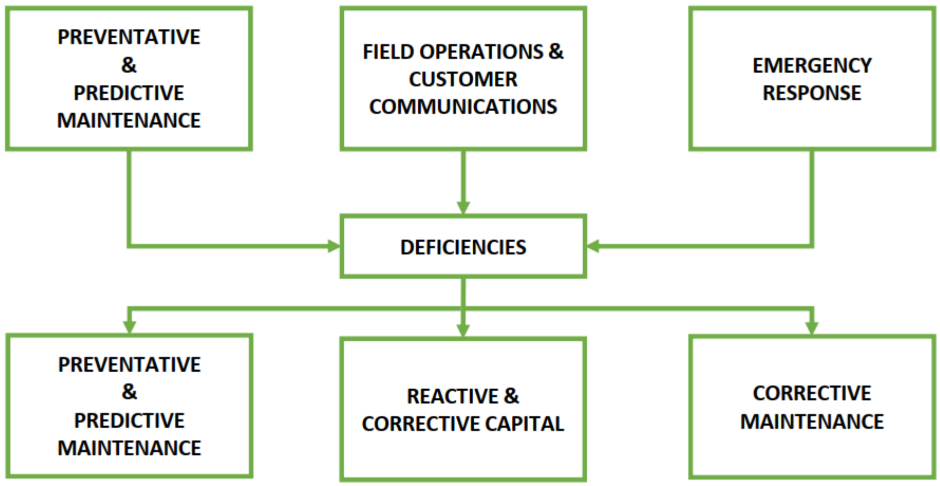


Figure 1: Deficiency Capturing Process

Distribution system events such as power outages are initially addressed through the Emergency Response program.[5] The cost of any capital work (e.g. major asset replacement) carried-out during an Emergency Response event is captured in the Reactive Capital program.[6] An Emergency Response event can also result in follow-up work to be carried out via the Reactive Capital segment.

The more substantial source of Reactive and Corrective Capital work is the identification of asset failures and deficiencies through maintenance activities and daily utility operations.

- Toronto Hydro's Preventative and Predictive Maintenance programs systematically identify asset failures and prioritize deficiencies through regularly scheduled system maintenance activities. Through the "find it and fix it" practice, on-site repair of minor deficiencies is carried out.[7]

- Failures and deficiencies are also identified through daily field operations and customer contact. These include observations by field crews and system operators during the normal course of operations, external emails, customer inquiries requiring field assessment and follow up including phone calls received from the customer service team, and meter errors captured through internal data collection systems.

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[5] Exhibit 4, Tab 2, Schedule 5.
[6] Exhibit 2B, Section E6.7.
[7] Exhibit 4, Tab 2, Schedules 1-3.

These processes and activities can result in both capital and operating expenditures (e.g. corrective tree trimming). The Corrective Maintenance program,[8] is the operational counterpart to the Reactive Capital segment.[9]

Toronto Hydro has a rigorous process for reviewing all work inquiries from these sources to validate the need for reactive intervention, assess the nature of reactive intervention required (i.e. capital versus maintenance), and the level of urgency/priority to be assigned to each item. Prioritization of the asset deficiencies identified as part of the work request process is based on the urgency of the work and how quickly it needs to be resolved. The work requests are classified into three categories (P1, P2, and P3) as discussed in Section D3.2.1.3 and illustrated in Figure 2. Toronto Hydro also identifies a P4 category of deficiencies, which require monitoring, but for which no work requests are issued.

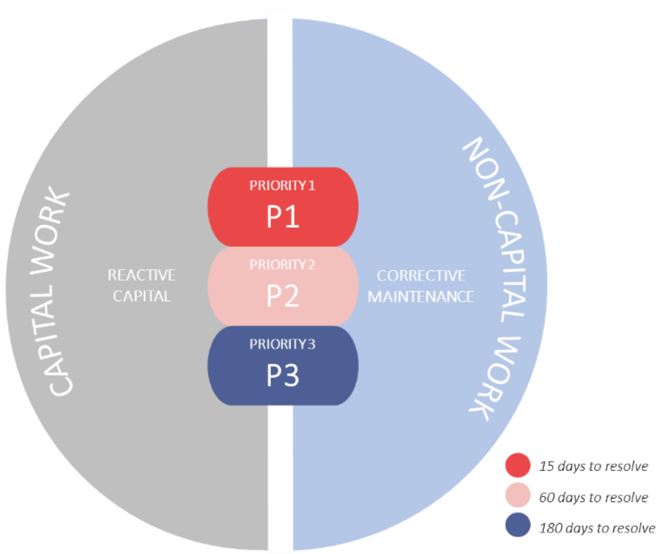

Figure 2: Work Request Prioritization

1. Preventative Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed or variable cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are typically defined based on the average time between

[8] Exhibit 4, Tab 2, Schedule 4.
[9] *Supra* note 6.

failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventative maintenance task is the inspection of wooden utility poles, which Toronto Hydro currently carries out on a ten-year cycle and intends to shift to an eight-year cycle in the next rate period.[10]

2. Predictive Maintenance

Predictive maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure. The results of this process feed into asset investment decision-making frameworks such as Toronto Hydro's Asset Condition Assessment, and will trigger corrective tasks to prevent failures when necessary. Predictive maintenance is the most effective maintenance approach for assets that exhibit conditions that can be identified, practically monitored, and corrected prior to failure. An example of a predictive maintenance task is the Dissolved Gas Analysis of power transformer mineral oil, which identifies the presence of dissolved gases and other chemical compounds in the oil as an indication of potential failure modes (e.g. overheating, excessive moisture, or breakdown of the insulating paper). Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information.[11]

3. Emergency Maintenance

Emergency maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to restore or maintain power in Toronto Hydro's distribution system. This type of maintenance may also involve an immediate response to a safety or environmental hazard. Emergency Maintenance can arise from: response to requests for support from Toronto Emergency Management Services and the public, equipment failure, events related to severe weather, motor vehicle accidents, power quality issues, and reactive equipment isolations. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of emergency maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines.[12]

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[10] *Supra* note 7.
[11] *Ibid.*
[12] Exhibit 4, Tab 2, Schedule 5.

4. Corrective Maintenance

Corrective Maintenance involves repairing equipment after a deficiency has been reported via preventative and predictive maintenance tasks or other sources, such as inquiries from customers, feeder patrols, and deficiencies identified by crews during day-to-day operations. Corrective work activities contribute to maintaining safety, environmental integrity, and overall system reliability. These tasks typically involve a short planning horizon since a portion of the distribution system is faulted, isolated, or in otherwise in an unacceptable condition.

Corrective Maintenance contributes to public and employee safety by ensuring prompt repair or replacement of high-risk assets or asset components approaching imminent failure; eliminating safety risks such as trip hazards caused by sink holes on sidewalks and the absence of adequate pole guying, washing insulators located in high contamination areas to prevent flashover, and detection and elimination of energized contact voltage on surfaces and structures within Toronto Hydro's distribution system. Corrective work also contributes to Toronto Hydro's environmental objectives, for example by repairing cables and splices exhibiting signs of oil deficiency to prevent oil spills into the environment, and prevention of excessive corrosion by cleaning oil-filled equipment and applying corrosion inhibiting coatings. Other examples of Corrective Maintenance tasks include: (i) the replacement of a cracked porcelain insulator; (ii) the repair of a broken guy wires; (iii) the removal of vegetation growing on a pole and into an overhead line; or (iv) the replacement of a conductor splice.

Corrective maintenance can also be required as a result of an unplanned system events or emergencies. For example, a faulted section of underground cable that had been isolated from the system during an emergency response can be unearthed and repaired or replaced as a Corrective Maintenance action. For additional information, please refer to the Corrective Maintenance program.[13]

D3.1.1.3 Impact of Capital Investments on Maintenance

Toronto Hydro routinely assesses the impact of its capital investments on distribution system maintenance needs and planning. A significant portion of maintenance program expenditures is directed toward activities that are independent of capital investments, including: (i) routine maintenance to preserve asset performance over its expected life; (ii) vegetation management to

[13] *Supra* note 8.

maintain minimum clearance requirements for overhead conductors and equipment; (iii) and cyclical patrols and inspections undertaken to comply with minimum requirements under the Distribution System Code; and (v) emergency maintenance following severe weather and storm damage. Maintenance programs also provide the asset condition information necessary to plan sustainment programs. Where there is an impact, the directional relationship between capital investments and maintenance depends on a number of factors, including the type of investment (e.g. Growth and City Electrification, Sustainment and Stewardship, or Modernization), mandated requirements (e.g. OEB minimum inspection cycles), and the specific characteristics of the assets involved.

Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increase to accommodate new customers. For example, the addition of Copeland TS (Phase 1) has increased the number of TSs (and station assets) that the utility has to regularly inspect and maintain, with some of these inspections occurring on a monthly basis. The expansion of Copeland TS (Phase 2) will similarly increase the number of station assets requiring maintenance, once complete. While these types of large, discrete S=stations expansion projects are fairly infrequent, more routine growth investments also tend to increase the total number of assets that must be incorporated into Toronto Hydro's existing preventative and predictive maintenance cycles. For example, from 2017 to 2022 the number of distribution transformers on Toronto Hydro's system increased by over 750 and the number of poles increased by over 4,500. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time, expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets under the Preventative and Predictive Station Maintenance program,[14] and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program.[15]

Within the Sustainment and Stewardship investment category, typical like-for-like asset replacement is generally expected to have no impact on routine maintenance and inspection requirements, especially where, as is most common, these investments are aimed at maintaining rather than improving overall asset condition. In certain cases, where Toronto Hydro conducts condition-based maintenance (increased frequency of maintenance activities for higher-risk assets within a population based on condition assessments), the utility could potentially reduce the number of

[14] Exhibit 4, Tab 2, Schedule 3.
[15] Exhibit 2B, Section E7.2.

assets requiring the higher maintenance frequency through capital investments aimed at improving condition demographics. As an example of condition-based maintenance, Toronto Hydro increased the frequency of inspections for Submersible Transformer during the period of 2019-2020 to manage the incremental risk posed by oil deficiencies within the submersible transformer population at that time prior to returning to a three-year cycle once the risk has been adequately managed. Typically, the impact would be minimal and this approach is not consistent with Toronto Hydro's general sustainment strategy to maintain asset condition. Similarly, like-for-like replacement activities will only reduce aggregate Corrective Maintenance expenditures if replacements are done at a high enough pace to materially improve asset health demographics, which could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, even this dynamic can be complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets, due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). In reality, Toronto Hydro has seen a rise in the volume of corrective work requests. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which the utility expects will continue to grow.

Where Sustainment and Stewardship investments are removing legacy and functionally obsolete assets or configurations from the system, this can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. Toronto Hydro anticipates that Sustainment and Stewardship programs targeting legacy assets such as air-blast circuit breakers, non-submersible network protectors, porcelain insulators, box construction, and rear lot construction will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs, or are maintenance free. For example, unlike newer types of circuit breakers, air-blast circuit breakers require air compressors to function, and Toronto Hydro inspects and maintains these air compressors twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through its Stations Renewal program,[16] it will aim to reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[17] Sustainment and Stewardship programs, including Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal, also contribute to the gradual removal of the legacy 4.16 kV system, which enables the decommissioning of Municipal

[16] Exhibit 2B, Section E6.6.
[17] Exhibit 4, Tab 2, Schedule 3.

Stations, reducing the overall volume of station maintenance and inspection activities. At the same time, new equipment, and new standards and practices may introduce incremental maintenance requirements. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Replacement of legacy systems can also help to reduce emergency and corrective maintenance. Legacy designs in poor condition may require more frequent corrective or emergency repair as more components are expected to fail, and there is an increased risk to reliability, safety, and environment outcomes. In addition, obsolete assets and configurations can have access, capacity, and procurement issues that may increase costs during corrective or emergency work. For example, both the Rear Lot and Box Construction configurations addressed by the Area Conversions program are targeted, in part, because of the challenges crews face in accessing them for repairs and the corresponding tendency towards longer outages.[18] Rear Lot feeder outages are on average 2.5 hours longer than outages on the rest of the system and these feeders can be particularly vulnerable to outages during adverse weather contributing to higher emergency maintenance costs. In May of 2022 there was a derecho wind storm which interrupted power to approximately 142,000 Toronto Hydro customers including customers on three Rear Lot feeders, which were out for more than two days, with the longest lasting 53.1 hours.

Modernization investments often have the greatest potential to reduce maintenance costs, although like growth investments, they tend to include the installation of new assets, such as SCADA-mate switches and reclosers under the System Enhancements program,[19] which contribute to increasing volumes of routine maintenance and inspection activities. The Network Condition Monitoring and Control ("NCMC") program is one modernization investment that has a clear benefit in terms of reducing expected maintenance costs.[20] As a result of the implementation of NCMC, which installs sensors in network vaults providing remote monitoring and control, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned.[21]

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[18] Exhibit 2B, Section E6.1.
[19] Exhibit 2B, Section E7.1.
[20] Exhibit 2B, Section E7.3.
[21] Exhibit 4, Tab 2, Schedule 2.

D3.1.1.4 Overview of Toronto Hydro's Refurbishment Practices

Both maintenance and refurbishment involve intervening on an asset to maintain or maximize its serviceability. Maintenance consists of activities that are necessary to ensure the reliable operation of an asset over its expected useful life. Refurbishment differs from maintenance in that it involves renovating an asset to extend its serviceable life. For example, tree trimming is a form of maintenance, while rebuilding a vault roof is a form of refurbishment.

Toronto Hydro's refurbishment efforts are mainly focused on assets that have been taken out of service (e.g. through a renewal project or as a result of failure). An asset may be considered for refurbishment if it meets specific criteria and is in good enough condition to be reintroduced into the system after appropriate testing. This is done for major asset types like transformers, network protectors, switchgears, and switches. Toronto Hydro evaluates major equipment returned from the field, and categorizes it based on the following criteria:

1) **Decommissioned equipment that remains operational:** Should a major asset such as a station power transformer be removed from the system as part of a system renewal project, or due to station decommissioning, Toronto Hydro will inspect and test the equipment to determine if it is still fit for service. If the equipment is still operational, the utility will keep it as a spare in case of reactive replacements.
2) **Repair of failed or defective equipment:** Equipment will be repaired or refurbished if it meets the following criteria: (i) it is under warranty; (ii) it is a critical spare (e.g. 4 kV assets); (iii) transformers less than 15 years old; (iv) network protectors less than 10 years old; (v) overhead switches less than five years old; or (vi) underground switches less than 15 years old. An example would be load conversion, where 4 kV equipment is removed from the system and replaced with the current standard. The removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types and in the event that other 4 kV assets on the system need to be replaced reactively.

Equipment that does not meet the specific criteria for re-use listed above will be scrapped.

Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault.

D3.1.2 Asset Replacement Practices

The decision to replace an asset can result from many drivers, including asset failure, deterioration and failure risk, functional obsolescence, historical performance, standards alignment, planning and execution efficiencies, capacity requirements, and third-party requests.

Failure, failure risk, and functional obsolescence are the three most significant trigger drivers for asset replacement for Sustainment and Stewardship investments. Renewal-driven replacement practices for specific asset classes can range from primarily reactive replacement, where replacement largely occurs when the asset has failed (i.e. it can no longer serve its intended function), to primarily proactive replacement, where the consequence of failure for an asset class (i.e. the asset's criticality) is high, making it unacceptable to run the asset to failure under most circumstances.

While a few asset classes are situated at the far ends of the reactive-proactive spectrum, Toronto Hydro manages most major asset classes using a blend of reactive and proactive replacement strategies. This approach reflects how the risk profile and specific performance challenges within and across asset classes evolves over time, particularly in a large, dense, and congested city served by a variety of highly utilized systems inherited from several predecessor smaller utilities. It also reflects variability in the location-specific criticality of individual assets across the system. The proportion of assets the utility replaces proactively is related to the utility's performance objectives and the risk assessments underlying projected performance.

The overall pace of asset replacement over time is also determined by long-term system stewardship objectives in accordance with good utility practice. As a steward of the grid, if Toronto Hydro expects a large demographic "wall" or "wave" of end-of-life assets approaching within a 10-15-year period, it has a responsibility to assess the impact and reasonability of smoothing out the investment profile. Practically this entails replacing a subset of the assets sooner, rather than waiting until the wave hits and being forced to replace all assets within a tighter window. This approach is preferred because it creates a more stable investment profile, leading to more realistic and efficient project resourcing and execution. It also has the benefit of yielding more predictable and stable rate impacts for customers. Increasingly, customers support investments that provide longer-term benefits. When specifically asked to make trade-offs between price and other outcomes (system health, reliability and efficiency) regarding these type of stewardship investments, the majority of customers surveyed agreed that Toronto Hydro's draft plan struck the right balance, with many customers expressing a preference for Toronto Hydro to spend more.[22]

The reverse of this dynamic is also relevant: if Toronto Hydro sees longer-term needs for an asset class easing-up over time, the utility may choose to slightly delay a proportion of necessary short-term investments, effectively accepting some short-term incremental asset failure risk in favour of a smoother investment profile and the related benefits. Note that with the emerging drive toward electrifying consumer loads (e.g. electric vehicles; heat pumps), Toronto Hydro anticipates that opportunities to defer asset replacement may be fewer in the future, since the utility is likely to face a higher rate of urgent low-voltage expansion needs (e.g. upsizing pole-top transformers to accommodate greater peak demand at the neighbourhood level).

Tables 2 to 6 below provide an overview of Toronto Hydro's current replacement practices for assets on each part of the distribution system.

[22] Exhibit 1B, Tab 3, Schedule 1

1 **Table 2: Summary of Overhead System Asset Replacement Practices**

Asset	Asset Replacement Practices
Poles	Toronto Hydro manages the risk profile of its pole population by proactively replacing poles in alignment with condition demographics and other risk factors (e.g. legacy asset replacement needs). Poles are replaced on an individual basis or as part of area rebuilds. Poles are prioritized for replacement based on condition, age, criticality, and relationship (e.g. proximity) to other high-risk assets. In the event poles fail while in service, Toronto Hydro replaces them reactively. Due to the urban environment in which Toronto Hydro operates, the utility has a very low risk appetite for catastrophic pole failure (i.e. collapse of pole) and designs its pole testing, inspection and reactive replacement programs to substantially mitigate this risk. During pole replacements, deteriorated and obsolete accessories such as porcelain insulators are also replaced because they are susceptible to contamination build-up, which can lead to asset failure and pole fires.
Pole-top Transformers	Toronto Hydro manages the risk profile of its pole-top transformer population through proactive and reactive replacement. The utility prioritizes transformers that present heightened failure risks based on inspection results, age, area reliability, and environmental risks (e.g. oil leaks containing polychlorinated biphenyls ("PCBs")). Due to the low individual criticality of a typical, PCB-free pole-top transformer, Toronto Hydro will generally replace these assets reactively or as part of a larger proactive area rebuild project when there are economies of scale. Toronto Hydro plans to replace the remaining "PCB at-risk" transformers in the distribution system to minimize failures and environmental risk. Toronto Hydro also expects that, due to the emerging pressures of electrification, space and capacity constraints will increasingly be a factor in the decision to schedule a pole-top transformer for proactive replacement.
Overhead Switches	Overhead switches are constantly exposed to harsh environmental conditions, and their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. Where appropriate, switches are replaced as part of a planned area rebuild, or else reactively upon failure due to age, condition, or external factors. Where safety risks are identified for a type or class of switches, the utility executes planned replacements of these assets to mitigate the risks.

Asset	Asset Replacement Practices
Overhead Conductors (primary and secondary)	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate, conductors are replaced as part of a planned area rebuild (e.g. upgrade to tree-proof conductor in heavily treed areas) or reactively upon failure due to age, condition, or external factors. Toronto Hydro expects that, due to the emerging pressures of electrification, capacity constraints on the secondary conductor buses which supply low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.

Table 3: Summary of Underground System Asset Replacement Practices

Asset	Asset Replacement Practices
Underground Cables (Polyethylene)	Toronto Hydro manages the risk profile of its underground cable population by both proactively and reactively replacing polyethylene (e.g. cross-linked polyethylene ("XLPE")) cables. The utility proactively replaces aged or poor performing cables through neighbourhood rebuild projects to manage significant reliability risks associated with these assets, mainly targeting poor performing direct-buried cables in the Horseshoe area. Otherwise, if these cables fail while in service, they are repaired or replaced reactively. With the introduction of a new Cable Diagnostic Testing program, Toronto Hydro is leveraging new forms of asset condition information to prioritize cable and cable accessory replacements both reactively and on a planned basis.
Underground Cables (Lead)	Underground lead cables have traditionally been replaced reactively on the downtown underground distribution system. However, with increasing reliability, safety, and operational risks associated with lead cables (i.e. leaking cables, congested cable chambers, increasing numbers of splices, dwindling supply and expertise), Toronto Hydro started to proactively replace paper-insulated lead-covered cables and asbestos-insulated lead-covered cables in 2020 and will continue to do so until the population is fully removed. The utility uses risk-based prioritization, which considers historical failures, age, feeder uniformity based on cable type, and the magnitude and criticality of the load served by each feeder to direct expenditures to the projects with the greatest customer value. Aside from the modest proactive investments that are planned for the 2025-2029 period, these cables are repaired or replaced reactively when they fail while in service.

Asset	Asset Replacement Practices
Underground switches	Toronto Hydro manages the risk profile of underground switches by proactively replacing them, taking into consideration age, condition, and failure impact. Toronto Hydro also plans to replace switches as part of area rebuild projects. Otherwise, switches that fail while in service are replaced reactively.
Underground Transformers	Toronto Hydro manages the risk profile of its underground transformer population through proactive and reactive replacement. Underground transformers are replaced as part of planned area rebuilds or on an individual basis if they pose an environmental risk due to the risk of leaking oil containing PCBs and are at or past their useful life and/or in deteriorating condition. Otherwise, transformers that fail while in service are replaced reactively. Toronto Hydro expects that, due to the emerging pressures of electrification, constraints on the secondary distribution system which supplies low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.
Underground Legacy Switchgear	Historically, Toronto Hydro has replaced underground legacy switchgear in customer-owned vaults reactively. However, due to the growing number of deficiencies where repairs are not an option and require replacement due to obsolescence, the utility is introducing proactive replacement of these legacy assets starting in 2025. Toronto Hydro plans to target the worst condition and most critical assets to maintain reliability performance and reduce safety risks, prioritizing them according to condition, inspection and maintenance history, and past reliability.
Cable Chamber	Toronto Hydro manages the risk profile of its underground cable chambers by proactively replacing cable chambers in HI5 and HI4 condition due to the growing number of deteriorating chambers and the complexity of chamber reconstruction work. Cable chambers are also prioritized based on the types of customers and thermal loading of feeders. Otherwise, cable chambers that fail while in service are addressed reactively. The utility plans to proactively replace cable chamber lids to address public safety risks in high traffic areas.

Asset	Asset Replacement Practices
Underground Residential Distribution ("URD")	Toronto Hydro manages the reliability performance for customers served by the unique URD system by proactively replacing URD assets. Toronto Hydro targets critical and obsolete URD assets in deteriorating and poor condition or past their useful life such as switching and non-switching vaults, switches, and transformers that contribute to the deterioration of system reliability. The utility prioritizes URD replacement projects based on the condition of civil roofs as deficient roofs pose an immediate risk to the public. Otherwise, assets that fail while in-service are replaced reactively.

1 **Table 4: Summary of Network System Asset Replacement Practices**

Asset	Asset Replacement Practices
Network Units	Toronto Hydro manages the risk profile of its network unit population by proactively replacing units in alignment with condition demographics and other risk factors (e.g. safety and environmental risks). The utility proactively replaces network units with a higher risk of failure due to age, condition, obsolescence, or location (i.e. prone to flooding). Older units with obsolete "non-submersible" protectors, which make them susceptible to water ingress causing failure, are generally beyond their useful life and are at risk of leaking oil containing PCBs. The utility is aiming to reduce and eventually eliminate the population of non-submersible units due to increasing risks of flooding. Otherwise, units that fail while in service are replaced reactively. Toronto Hydro continues to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.
Network Vaults	Toronto Hydro manages the risk profile of its network vault population by proactively replacing vaults or vault roofs in alignment with condition demographics and other risk factors (e.g. safety risks). Due to the complexity of vault rebuild projects, Toronto Hydro must maintain a steady pace of renewal targeting the worst condition locations. Vaults are prioritized primarily based on condition and the associated safety risks of structural deterioration, customers served, and external factors (i.e. road moratoriums). If a deteriorated vault is no longer needed due to load displacement, then the utility will decommission it. Otherwise, vaults that fail while in service are addressed reactively.
Network Cables	See Underground cables – polyethylene and lead.

1 **Table 5: Summary of Stations Asset Replacement Practices**

Asset	Asset Replacement Practices
Transformer Station ("TS") Switchgear	Toronto Hydro manages the risk profile of its TS switchgear population by proactively replacing assets to manage overall switchgear demographic risk and system reliability. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Asset replacements need to be done proactively, as they have long lead times to procure (e.g. 12-18 months), and design and construct (e.g. 3-4 years). Replacement prioritization is dependent on various factors, including: age, enclosure construction, load, arc flash rating, breaker condition, obsolescence, and safety. These assets can fail while in service, and in such situations, customers may experience long outages while Toronto Hydro restores power and subsequently repairs or replaces the failed switchgear reactively.
TS Oil Circuit Breakers (KSO)	Toronto Hydro manages the risk profile of its TS oil circuit breaker population by proactively replacing assets. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively as they have long lead times. Toronto Hydro replaces TS KSO oil circuit breakers based on age, condition, load, obsolescence, and safety and environmental risks (i.e. oil containing PCBs). Otherwise, assets are replaced reactively when they fail while in service.[23] Given the above risks, Toronto Hydro plans to remove all remaining KSO Oil circuit breakers from the system in the 2025-2029 period.
Municipal Station ("MS") Switchgear	Toronto Hydro manages the risk profile of its MS switchgear population by proactively replacing them. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively due to long lead times. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Toronto Hydro replaces MS switchgear based on age, breaker condition assessment results, type of circuit breaker, load, the obsolescence of the asset, resiliency of the surrounding distribution system to withstand switchgear failures, and the safety and reliability risks they present. New MS switchgears are arc-resistant. When these assets fail while in service, Toronto Hydro will first attempt to repair the unit, but depending on the severity of the fault, may replace it reactively.

[23] *Supra* note 16.

Asset	Asset Replacement Practices
MS Primary Supply	MS primary supply assets (disconnect switches, cables, and circuit breakers) are proactively replaced to maintain overall condition demographics and reliability. MS primary supply assets are replaced proactively as part of MS power transformer replacement projects and may be included as part of switchgear replacement projects. Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. Toronto Hydro proposes to continue to replace the primary supply at MSs where power transformers were previously replaced, but only where the primary cable is direct buried or in direct buried duct since this comprises the majority of the failure risk. MSs targeted for primary supply replacement are prioritized based on failure risk as determined by age and configuration (e.g. direct-buried cable). It takes three months to reactively replace a failed primary supply.
Power Transformers	Toronto Hydro manages the risk profile of its power transformers by proactively replacing them to manage overall demographic risk and system reliability. Power transformers require long lead times (e.g. 12 months) to procure, design and construct and therefore need to be replaced as part of a steady proactive renewal program. These assets are prioritized based on condition assessment, age, dissolved gas analysis, load, and resiliency of the surrounding distribution system to withstand transformer failures. Toronto Hydro plans to increase pace of power transformer replacement to address an increasing power transformer failure rate.
Station Service Transformers ("SSTs")	Toronto Hydro replaces SSTs proactively to manage age demographics and maintain reliability on the system. Asset replacement also requires long lead times and as a result, needs to be done proactively. Units are prioritized based on their age and associated environmental risk (i.e. risk of oil containing PCBs). Once these assets fail in service, the station service supply cannot afford to experience a subsequent failure as that failure would render the station inoperable. Moreover, any planned renewal or maintenance work of ancillary systems may be delayed.
Remote Terminal Units ("RTUs")	Toronto Hydro replaces functionally obsolete RTUs proactively as they are beyond their useful life, and no longer supported by their manufacturers. These assets can be repaired within a two-week period; however, repairs cannot be maintained over the long term due to the scarcity of spare parts. These assets also have a long replacement time (e.g. six months) and are therefore difficult to replace reactively. These assets are prioritized based on age, number of customers connected, load and failure rate.

Asset	Asset Replacement Practices
Relays & Copper Communication Cable	Toronto Hydro replaces relays proactively, mainly driven by obsolescence and the need to support grid modernization, but also driven by failure risk due to age. Copper communications cables are replaced proactively with fiber to mitigate the failure risk associated with older cables and to allow Toronto Hydro to have complete control, since many of the copper communication cables in the system are owned by third-parties. Assets are prioritized according to the number of customers and load connected, and failure rate of the station.
Direct Current ("DC") Battery Systems	Toronto Hydro replaces and maintains DC battery systems to ensure they can supply power to the station for eight hours (as mandated by the Transmission System Code). Replacement of the assets is prioritised based on functional obsolescence, age, and condition of the asset.
AC Panels	Toronto Hydro proactively replaces AC panels to mitigate failure risk of obsolete and end-of-life assets. An AC panel failure has a large impact because they supply all the station loads such as heating, cooling, lighting, ancillary equipment and DC charging systems with no backup supply in case of failure. AC panel replacements are prioritized based on age and the number of customers connected to the station.

1 **Table 6: Summary of Metering Asset Replacement Practices**

Asset	Asset Replacement Practices
Meters	Toronto Hydro replaces meters proactively at or beyond the end of their useful life to manage risk of failure and customer billing interruptions. Meters are replaced reactively if they fail to read or communicate or suffer complete failure. Reactive meter replacement consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters and primary meters.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These assets can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained within a constrained expenditure plan. Risk assessments are also used to determine areas of the system that would benefit the most from investments in grid modernization.

This section outlines Toronto Hydro's lifecycle risk management methods and practices for its distribution assets, detailing the utility's risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro's risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure ("PoF") is an important consideration in determining whether asset intervention is necessary. This section focuses upon three key forms of analytics that Toronto Hydro uses to enable PoF evaluation: (i) Asset Condition Assessment ("ACA"); (ii) predictive failure modelling; and (iii) Historical Reliability Analysis.

1. Asset Condition Assessment ("ACA")

As explained in Section D1 and in Appendix A to this Section, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a Health Score to support project planning. The ACA allows Toronto Hydro to use data collected through inspections to produce a relative numerical representation of an asset's condition, considering key factors that affect its operation, degradation, and lifecycle.

Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and health scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

The ACA model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology. This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, the Office of Gas and Electricity Markets ("Ofgem").[24] The methodology provides a health score for every applicable asset based on the most recent inspection information. The methodology also projects Future Health Scores for assets, which provides intelligence on asset demographics that the utility leverages to evaluate proposed investment strategies over longer periods. Since the adoption of CBRM in 2017, Toronto Hydro's Health Score calculations and projection methodologies have remained largely consistent, with the

[24] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

exception of certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

The general approach used to produce the health score for each asset is illustrated in Figure 3.

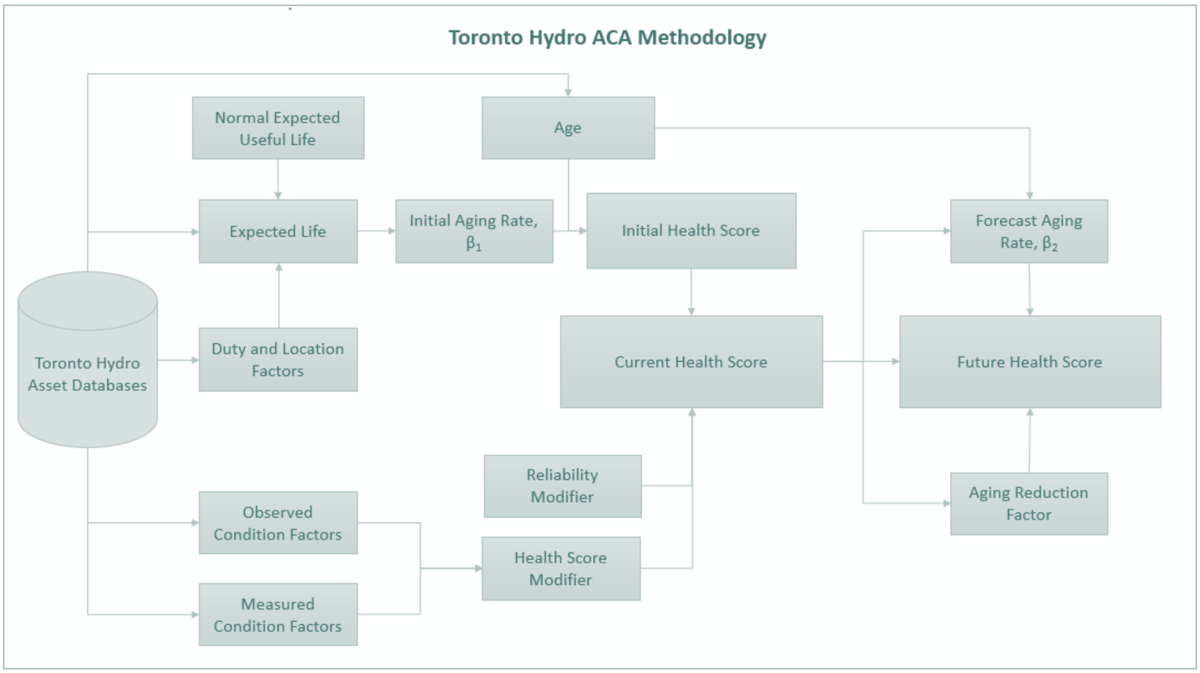


Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset health demographics and the underlying inspection details during the project scope development phase of IPPR, as outlined in Section D1. This enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

Asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA highlights trends in the condition of asset populations. For system planners, these insights provide an indication of the relative probability of failure for an asset and how failure risk within an asset population is evolving over time. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and future HI results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2025-2029 Distribution System Plan ("DSP"), Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5").

As highlighted in Section D1.3.2.1, and as a next step in the evolution of the utility's ACA approach, Toronto Hydro is in the process of implementing the Probability of Failure component of the broader CBRM methodology. This extension of the methodology will allow the utility to convert an asset Health Score (which serves as an indirect indicator of relative PoF) into an absolute PoF value which can then be applied in quantitative risk-based decision-making frameworks, including the utility's value framework for capital investments. The role of PoF in these frameworks is discussed further in the following section.

2. Predictive Failure Modelling

Predictive failure modelling is another essential component of Toronto Hydro's approach to risk-based asset management. Predictive failure modelling involves the derivation of hazard rate functions for each asset class and the application of said functions to existing and future asset population demographics to produce a predicted number of failures per year. The utility leverages these failure models to support risk-based investment decision-making and system performance projections.

A hazard rate, commonly used in reliability engineering, represents the instantaneous likelihood of failure given that an asset has survived up to a particular time. To the extent that North American distribution utilities like Toronto Hydro have pursued quantitative risk-based asset management tools in recent decades, they have typically relied upon age-based hazard rate functions to produce quantified PoF values. In Toronto Hydro's case, while age-based PoF is currently the more mature mode of analysis for analytics such as reliability projections, the utility is in the process of introducing condition-based PoF as an enhancement to its decision-making tools and analytics. As noted above, this condition-based PoF is an extension of the Health Score concept within the CBRM framework.

As discussed in Section D1.2.1.1, as part of its ongoing multi-year effort to implement an industry leading Engineering Asset Investment Planning ("EAIP") platform, Toronto Hydro is developing a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the utility's CBRM framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. The condition-based PoF values will serve as an important input to this framework.

The role of predictive failure modelling in reliability projection procedures is discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The third component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data in order to identify failure trends for asset populations and areas of the system.

Toronto Hydro's reliability analytics system stores historical outage information which the utility uses as a tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro can identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;
- Tree Contacts; and
- Unknown.

From a probability of failure perspective, this data can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. In specific scenarios, historical reliability performance can be a strong indicator of future issues. As an example, reliability data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability of failure (explained in Section D3.2.1.1) and the consequences of failure. Consequences are generally broken down into major categories (e.g. safety consequences) that align with Toronto Hydro's corporate pillars and outcomes framework.

1. Reliability

Toronto Hydro evaluates reliability consequences associated with its assets using a mix of quantitative and qualitative information:

- Reliability performance analysis;
- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

1 **Table 9: Summary information used to establish Reliability Consequences**

Tool or Approach	Summary
Reliability Performance Analysis	As explained above in Section D3.2.1.1, Toronto Hydro's reliability analytics system keeps detailed records on outage events. The utility mines this data to gather insights into the frequency and consequences of different kinds of events, including various modes of asset failure for the different types of assets on the distribution system. This analysis is useful for developing statistical averages and ranges that are applicable in risk modelling (e.g. average number of customers interrupted and average duration of an outage for a pole-top transformer failure on the 27.6 kV system). It is also useful in determining which asset sub-types and specific parts of the distribution system are exhibiting higher than average reliability consequences (e.g. quantifying the higher average outage duration consequences for events on the rear lot system). Toronto Hydro leverages these reliability analytics both directly and in combination with other leading and lagging indicators to establish the relative consequence of failure for different assets, and to establish investment priorities. Reliability analytics are also important for more dynamic, "in year" management of customer reliability impacts. For example, a distribution feeder that is experiencing a rash of outages in the short-term will be monitored more closely and intervened upon more urgently as a potential "worst performing feeder." Flagging a feeder as a worst performer effectively elevates the consequence of failure of each subsequent outage, since further deterioration in performance would violate management's standards for acceptable reliability.

Tool or Approach	Summary
Network/Reliability Consequence of Failure ("CoF")	As part of its ongoing efforts to implement an EAIP system, Toronto Hydro is developing a custom Value Framework that is aligned with its corporate pillars and outcomes framework. Network/Reliability CoF is one component of the framework. The Network/Reliability CoF models the customers interrupted and duration impact of asset failure, leveraging Customer Interruption Costs ("CIC") to quantify the cost of failure to customers. CICs represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: Event cost and Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage. Within the Value Framework, the event cost is calculated by multiplying customer interruption costs with total customers impacted for an asset failure. The duration cost represents the costs incurred as the length of the outage increases, calculated by multiplying the duration cost by the average time to restore power after an asset failure, considering time required for switching operations and repair or replacement. This component of the value framework, when combined with the PoF, will supersede the utility's legacy Feeder Investment Model as the primary means of assessing the impact of asset failure through a fully quantified and probabilistic risk lens.

Tool or Approach	Summary
Customer Engagement	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers that provide the utility with qualitative and quantitative insight into the customer's experience, needs, preferences, and priorities. This information can come through various channels, ranging from ad hoc customer interactions, to periodic engagements with larger customers, to infrequent but highly comprehensive investment planning-related engagements and surveys. Key examples include: • **Key Account Customer Program:** Toronto Hydro's Key Account Customers are those customers who have critical loads, including: customers who have electricity use greater than one MW at a single site or combined across a number of sites, priority loads such as hospitals and financial institutions, essential public services including the Toronto Transit Commission, schools, and developers. Toronto Hydro manages a key account customer program for these customers to address specific concerns and issues in a timely manner. The utility proactively engages with these customers on a wide range of topics including resolving issues related to reliability and power quality. These engagements help Toronto Hydro to calibrate its decision-making to ensure it is aligned appropriately with the customer's experience of outage and power quality events. • **Rate Application Customer Engagement:** Every five years, in preparation for its rate-setting application cycle, Toronto Hydro undertakes extensive Customer Engagement as part of business planning. This process produces a detailed and comprehensive view of high-level customer preferences when it comes to key outcomes including reliability and resiliency. Toronto Hydro uses this information to calibrate its investment strategy and ensure general investment pacing and prioritization is reflective of the customer's willingness to pay to avoid the reliability consequences of system faults.

2. Environmental

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment. Beyond the potential environmental impacts that can result from certain asset failure modes, Toronto Hydro can face associated consequences such as potential non-compliance or breach of regulatory obligations, which in turn can have severe reputational and financial implications.

Toronto Hydro's major environmental concerns include: (i) oil or SF_6 gas leaks of all types; (ii) reducing greenhouse gas emissions ("GHG"); and (iii) mitigating the use of substances like asbestos, lead, and PCBs in its equipment. Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and included for replacement with standardized and less harmful equipment. Toronto Hydro will mitigate the risk of oil spills containing PCBs on its overhead, underground and network systems by 2025 by replacing at-risk assets. Toronto Hydro is also acting to reduce SF_6 gas leakage into the environment. For example, the latest generation of SF_6-insulated switches Toronto Hydro installs have welded viewing windows that mitigate SF_6 gas leakage into the environment. Moreover, the utility is trialing Solid Dielectric ("SD") switchgear as an alternative to SF_6 insulated gear.

Toronto Hydro is including Environmental CoF as another component within its custom value framework as part of its EAIP implementation. The Environment CoF will reflect the above considerations, quantifying the impacts of oil and SF_6 gas leaks or contamination, GHG emissions, and equipment disposal. In addition, considerations for increased consequence due to the presence of substances such as PCBs will also be made in determining the overall environmental consequence of asset failure.

3. Safety

Mitigating safety risks to Toronto Hydro employees and the general public is the highest priority objective of Toronto Hydro's Asset Management process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Public and employee safety is the overarching priority of Toronto Hydro and is built into its culture, operations, and decision-making frameworks. Toronto Hydro continues to strive for zero public and employee safety incidents each year. Moreover, one of Toronto Hydro's objectives is to comply with all safety regulations and standards over the 2025-2029 period.

Toronto Hydro is implementing Safety CoF within its custom value framework. Safety CoF will quantify impacts to both public and crew safety, including direct and indirect costs associated with death or serious injuries, lost time injuries, and third- party damages resulting from asset failure.

Factors that impact the severity or probability of an injury, such as an asset's proximity to high traffic areas or the size of an asset, will also be considered within the overall Safety CoF.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometimes entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations;
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations;
- Addressing emerging safety risks identified by the Electrical Safety Association ("ESA") such as potential fire risks at "Delta-Wye" locations; and
- Reducing public safety risk due to cable chamber lid ejections

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with new standardized equipment. For example, delta-wye corrective work under the Corrective Maintenance program,[25] addresses the potential hazard of fire and shock posed by three-phase grounded wye-connected secondary transformation with no grounded neutral conductor between the transformer's secondary neutral terminal and the

[25] *Supra* note 8.

customer's service entrance equipment. This issue was flagged by the ESA and this work enables compliance to ESA requirements.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;[26]
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273,[27] and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers;[28] and
- Ensuring compliance with *Ontario Regulation* 22/4,[29] and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Financial CoF will be integrated within Toronto Hydro's value framework in order to reflect the direct financial costs of failure required to replace or repair an asset. Asset failure can also cause outages disrupting the normal operations of businesses, damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and any resulting litigation, in addition to asset replacement or repair costs. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

[26] *Occupational Health and Safety Act* , R.S.O. 1990, c. O.1 and *Canadian Environmental Protection Act,* 1999.
[27] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act,* 1999.
[28] Toronto Municipal code, Chapter 681 Sewers (July 27, 2023).
[29] O. Reg. 22/04: Electrical Distribution Safety, under Electricity Act, 1998, S.O. 1998, c. 15, Schedule. A.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions. The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Quantified Risk-Based Analysis

As mentioned in Section D3.2.1.1, Toronto Hydro is taking the next step in the advanced implementation of its risk frameworks by developing a custom value framework to inform its EAIP platform. The value framework will allow a quantitative assessment of the relative value for projects based on their alignment to key outcomes. It integrates risk assessments in quantifying the value for projects along with other value drivers, allowing the utility to consider the overall value of investments in decision-making and produce an optimized set of projects to achieve key performance outcomes.

Toronto Hydro's value framework, especially as it relates to Sustainment and Stewardship investments, is rooted in the CBRM methodology and is informed by both the probability and consequence of failure inputs discussed in Section D3.2.1.1 and D3.2.1.2 above. The value framework integrates incremental development within its ACA methodology (such as condition based PoF curves) along with quantified consequence of asset failure (CoF) as detailed in Section D3.2.1.2 above, specifically:

- Network/Reliability Consequences;
- Environmental Consequences;
- Safety Consequences; and
- Financial Consequences

The custom Value Framework embedded within its EAIP platform will allow Toronto Hydro to assess and understand the risk profile of its assets in order to support decision-making as it relates to its short- and long-term investments, including assessments of value for alternative approaches for intervention. Comparing the change in risk mitigation (value of investment), along with other value drivers, over multiple years allows Toronto Hydro to evaluate trade-offs between outcomes, resource requirements, and budgetary pressures year over year. Subsequently, Toronto Hydro can leverage the capabilities of its EAIP tool to establish an optimized set of projects to achieve performance outcomes in each year that is aligned with its outcomes framework.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data and associated failure projections;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level. For Defective Equipment, Toronto Hydro projected failure and outage impacts at an asset class level based on associated demographics, historical reliability, and the expected benefits of it's 2025-2029 planned Sustainment and Stewardship investments. The utility applied a historical five-year average to project other cause codes. It also included projections for the reliability related benefits of Grid Modernization investments.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond useful life and in deteriorated conditions, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces a scenario to project the reliability impact of the Sustainment and Stewardship programs and reliability related benefits of grid modernization programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate the reliability impact of the proposed capital expenditure plan. This analysis also supports Toronto Hydro in setting targets for reliability performance as part of its Custom Performance Measures for SAIDI (excluding Loss of Supply, Major Event Days, and Scheduled Outages) and SAIFI (Defective Equipment).[30]

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders performing poorly over a rolling 12-month period and performs work to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting criteria below:

- Non-key account feeders that are at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of seven or more, or "FESI-7").[31]
- Key Account feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "KAWPF-6").
- Key Account feeders that contain large critical customers with Ion meters installed at their service entrance that have their operations negatively impacted by multiple sustained or momentary interruptions and/or power quality issues. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.
- Feeders that are experiencing systemic issues in a localized area that are resulting in, or at risk of resulting in multiple sustained or momentary interruptions.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. Additional details

[30] Exhibit 1B, Tab 3, Schedule 2.
[31] Note that, with recent upgrades to the Network Management System and the ongoing transition to Oracle Utility Analytics for reliability analysis, Toronto Hydro is now capturing a greater number of very small outages. The utility is currently assessing the impact of this change on its FESI-7 measure (which counts individual outages equally, regardless of size) and may choose to redesign this feeder-based reliability the measure to more accurately reflect the experience of customers who are truly experiencing an unacceptable frequency of interruptions.

related to programs targeting worst performing feeders, which are in place to improve reliability and meet the needs of customers, may be found in Reactive and Corrective Capital program.[32] As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Exhibit 2B, Section C.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset management risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, the appropriate follow up actions are assigned based on the nature of the work. Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework is useful for assessing risk trends related to both particular asset classes and system overall.

Toronto Hydro reviews all deficiencies to determine appropriate actions and the level of priority to be assigned to each deficiency. Prioritization of the asset deficiencies as part of the work request process is based on the urgency of the work and the risk it poses. The work requests are classified into three categories:

[32] *Supra* note 6.

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

Toronto Hydro also identifies a P4 category of low priority deficiencies largely for the purposes of monitoring a deficiency, but no corrective work is issued. For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital,[33] Corrective Maintenance,[34] and Emergency Response programs.[35]

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third-party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short, medium, and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories.

[33] *Supra* note 6.
[34] *Supra* note 8.
[35] *Supra* note 5.

D3.2.2.1 Sustainment and Stewardship Investments

As part of Toronto Hydro's risk mitigation efforts, Sustainment and Stewardship investments form a significant portion of the utility's capital investments. These investments are geared towards maintaining the foundations of a safe and reliable system and standardizing outdated equipment. They aim to ensure long-term performance of Toronto Hydro's assets, maintain system reliability, and minimize asset failure risk. The Sustainment and Stewardship investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, Sustainment and Stewardship programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. They also include more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program.[36]

D3.2.2.2 Growth and City Electrification Investments

Growth and City Electrification investments allow Toronto Hydro to connect and serve growing demand for electricity as Toronto continues to grow, digitize and decarbonize key sectors of the economy. These investments ensure Toronto Hydro meets capacity and connection needs and is able to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. Toronto Hydro determines capacity and connection needs through the Stations Load Forecast, load connections forecasting, generations connections forecasting, and the Regional Planning process.[37] The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system, including enabling new or modified load and distributed generation connections to the distribution system.[38] Section D3.3 further discusses Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers.

D3.2.2.3 Modernization Investments

Modernization investments allow Toronto Hydro to adopt new technology to improve system performance and reduce costs over time, and to protect the system against intensifying threats.

[36] *Supra* note 6.
[37] Exhibit 2B, Section D4.
[38] Exhibit 2B, Section E5.1

Toronto Hydro invests in programs that allow for other cost-effective forms to mitigate the risks discussed in Section D3.2.1. For example, Toronto Hydro is investing in improving operational flexibility and observability through the System Enhancements program.[39] Installation of SCADA-Mate switches or reclosers allows Toronto Hydro to address reliability related risks, in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

Toronto Hydro is also investing in grid enhancement and modernization efforts to adapt to the changing needs of customers, environment, safety considerations, and stakeholders. The distribution grid faces pressure to support the energy transition and electrification such as the need to integrate increasing number of DERs and EVs in a safe and efficient manner. Toronto Hydro's Grid Readiness initiative aims to address the risk of increasing DERs and EVs proliferation. Moreover, Toronto Hydro's investments in Intelligent Grid initiative enhances observability and controllability of the grid, and mitigate risks around climate change and cybersecurity threats. For more information on the initiatives related to Grid Modernization, please refer to Exhibit 2B, Section D5.

D3.2.2.4 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.5 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada.

[39] *Supra* note 19.

D3.3 Asset Utilization Policies and Practices

This section highlights Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers. It details Toronto Hydro's process to assess capacity requirements, connections, and steps to mitigate risks.

D3.3.1 Capacity and Connections Capability Assessments

Toronto Hydro continues to monitor capacity related risks within its system from both a short- and long-term view point. This includes working with third parties such as the Transmitter (i.e. Hydro One Networks) and the Independent Electricity System Operator ("IESO") as required for planning purposes, for both load connections and generation connections.

D3.3.1.1 Distribution Capacity & Capability Assessments

1. **Peak Demand Forecasting**

Toronto Hydro uses a peak demand forecasting process to identify capacity constraints at substations within the system ("System Peak Demand Forecast"). This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made and natural load growth (or reductions) occur. The System Peak Demand Forecast provides a near-to-medium term view of the station bus capacity so that appropriate plans can be made to accommodate varying growth within the system.[40]

In order to complete a ten-year System Peak Demand Forecast at the substation level, as shown in Figure 5, Toronto Hydro identifies the annual non-coincident peak loads (both summer and winter peaks) for each individual bus at its substations. These peak loads are then normalized based on historical temperatures at which they occur.

Following this, additional load growth is added to each bus considering economic variables. Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centres, (ii) electrification of transportation, including EVs, and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. In addition, all customer connection requests and planned permanent work such as load transfers and voltage conversions are added to each bus.

[40] See Exhibit 2B, Section D4.1.1 for a detailed description of Toronto Hydro's Peak Demand Forecast methodology.

Lastly, probabilistic simulations are performed to produce the final peak demand forecast of non-coincident bus peaks. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

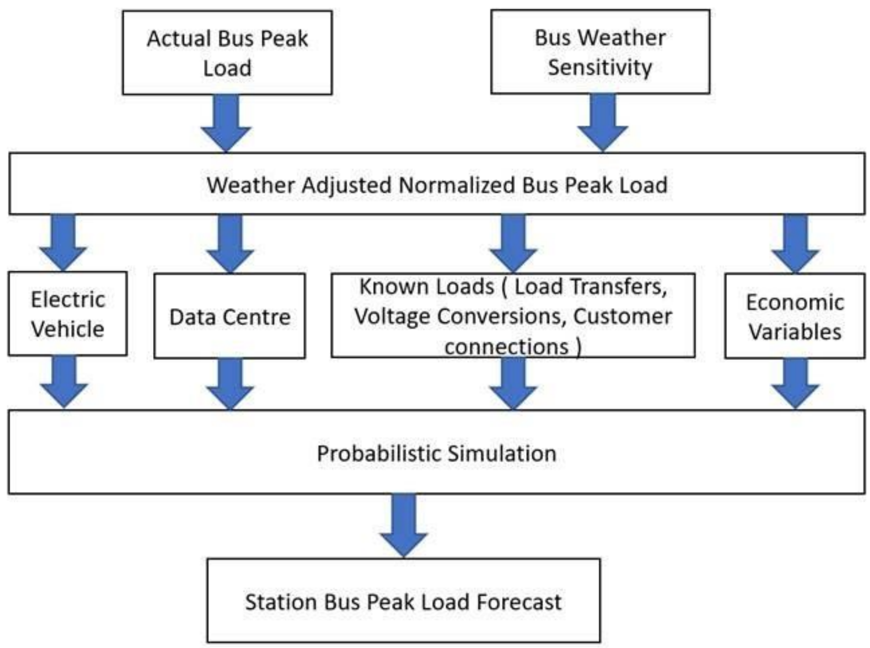


Figure 5: Process to Forecast Peak Demand at Substations

Recognizing the unprecedented energy transition set to unfold over the coming years, Toronto Hydro augmented its capacity planning and decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from the Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, the Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets, and constraints of decarbonizing the economy by 2040 or 2050.[41]

[41] Future Energy Scenarios model is described in more detail in Exhibit 2B, Section D4, Appendix A and Appendix B.

2. Connection Capability

In order to connect new customers, both capacity and spare feeder positions are needed. As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply this demand, if there are no feeder positions to connect new feeders to the station, then the station would be unable to support new connections. To this end, Toronto Hydro also monitors the number of spare feeder positions at its stations. When new feeders are needed and no spare feeder positions are available, Toronto Hydro engages in capital work under the Load Demand program to transfer feeder loads and free up feeder positions so that new customer connections can be made.[42]

D3.3.1.2 Generation Capacity & Capability Assessment

Increased demand for power from consumers and the interconnection of distributed energy resources ("DER") have placed limitations on certain areas of the system. Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions, including the following:

1) Short circuit capacity constraints;
2) Anti-islanding conditions for DER;
3) System thermal limits and load transfer capability; and
4) Protection and power quality challenges from high DER penetration.

To determine the impact of DER penetration on a station feeder, sophisticated fault and power flow simulation models are employed. These models provide visibility on different variables, such as fault current, and the contribution of those variables to the limiting constraints listed above.

Studies are performed for each new DER application enabling Toronto Hydro to continually evaluate the available existing short circuit capacity of the system.

[42] Exhibit 2B, Section E5.3.

D3.3.2 Capacity Risk Mitigation Methods

Based on the risk assessments above, Toronto Hydro invests in a number of programs to mitigate the risk of capacity shortfalls or the inability to connect new customers. These methods include expansion to increase capacity, enhancements to better utilize existing equipment, and load transfers as detailed below.

D3.3.2.1 Expansion Investments

Expansion investments provide one approach to manage the risk of capacity shortfalls within the system. By increasing capacity at substations, Toronto Hydro is able to address the need in localized areas of the system that experience load growth. Investments for expansion are primarily funded through the Stations Expansion program.[43] Expansion investments often require involvement from the transmitter, and Toronto Hydro may need to provide capital contributions for upgrades to transmission equipment at substations to enable an increase in capacity. Expansion may also be embedded as part of renewal activities for power transformers and switchgear units if deemed necessary, either to increase capacity or to increase the number of feeder positions available at a substation to provide new feeders to connect customers.

D3.3.2.2 Load Transfers

Prior to investing in expansion projects, Toronto Hydro assesses the feasibility to alleviate capacity shortfalls by transferring load to adjacent feeders, buses, or substations. If feasible, transfers are typically more cost effective than expansion. This approach allows Toronto Hydro to ensure efficient utilization of its existing infrastructure prior to investments in expansion.

D3.3.2.3 Enhancement Investments

Toronto Hydro also considers investments that allows it to enhance the system in order to alleviate capacity shortfalls or connection limitations, in a cost-effective manner. To manage load restrictions, especially due to peaks, Toronto Hydro has worked extensively with its customers to implement a Local Demand Response program to manage peak demand effectively and developed an Energy Storage Systems program.[44] For generation connections, investments in monitoring and control equipment are made through capital programs, including Generation Protection, Monitoring, and

[43] Exhibit 2B, Section E7.4.
[44] *Supra* note 15.

Control, to actively manage DER sources to ensure safe connections.[45] These investments allow Toronto Hydro to effectively manage capacity and connection limitations, without the need for extensive renewal activities, thereby deferring large capital investments. These investments form part of Toronto Hydro's Grid Modernization Strategy for 2025-2029.[46]

D3.4 Program Planning Approach and Project Development

This section details the framework and process that Toronto Hydro relies on to develop its capital and maintenance programs. It highlights the key components of the IPPR process that drives the development of investment programs, as shown in Figure 6.

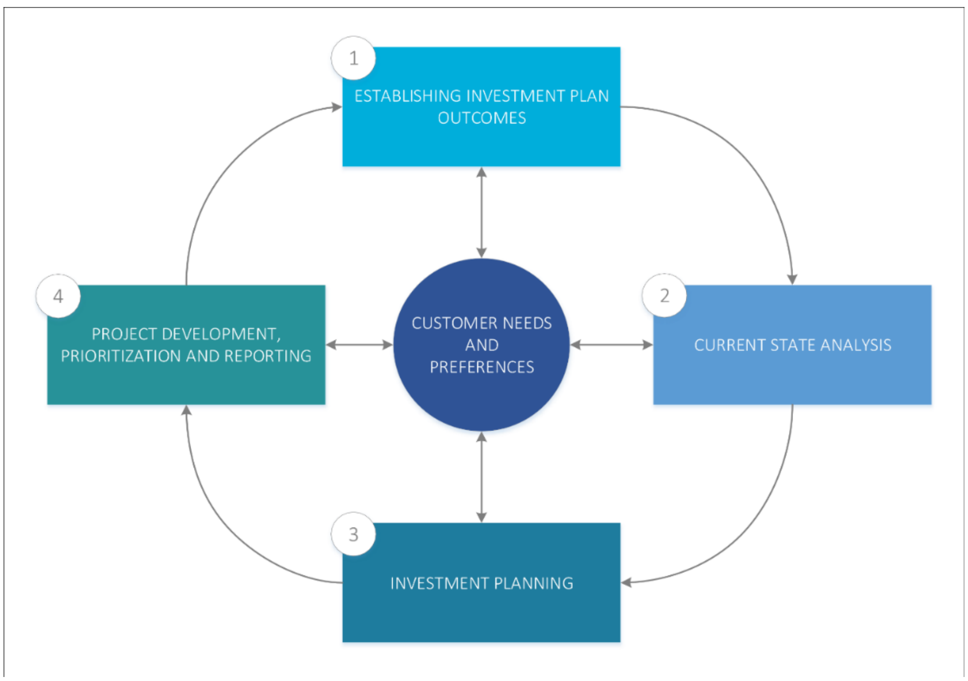


Figure 6: The IPPR Program Development Framework

The process can be divided into four key components:

1) **Asset Management Policy, Goals, and Objectives:** The process begins by establishing the asset management policy, goals, and objectives, and is informed by both the broader corporate strategy as well as customer needs, expectations, and feedback.

[45] Exhibit 2B, Section E5.5.
[46] Exhibit 2B, Section D5.

2) **Asset Needs Assessment:** This part of the process establishes an understanding of the current state of assets based on asset demographics and condition results. This information provides the base data required for planners to analyze the risk that the asset poses to the system.
3) **Portfolio Planning:** Based on the information output from the first two steps and the various risks discussed above, Toronto Hydro analyzes assets to identify the required level of spend to manage risk and in turn achieve the intended outcomes. Based on the driver of the work, investment programs are established as part of this step.
4) **Portfolio Reporting:** Once investment programs have been executed in the field through individual projects, the IPPR process includes a feedback loop where the project-specific execution status and project expenditures are reported to inform projects proposed in upcoming years.

D3.4.1 Asset Management Policy, Goals and Objectives

As discussed in Section D1, Toronto Hydro's Asset Management System ("AMS") is guided by its AM policy, goals, and related outcome objectives that the utility sets in alignment with its corporate pillars, objectives, and customer engagements. Figure 4 in Section D1 provides a summary of the AM policy, goals, and objectives, and Section E2 provides an overview of how Toronto Hydro established its AM outcome objectives for the 2025-2029 DSP.

Toronto Hydro uses outcome measures in each focus area to quantify the impact of investments towards each outcome. This framework is integral in enabling decision-making for asset management in both the long-term and short-term. For more details on Toronto Hydro's proposed Performance Measures for the 2025-2029 period, see Exhibit 1B, Tab 3, Schedule 1.

D3.4.2 Asset Needs Assessment

In order to create an optimized program, Toronto Hydro completes a needs assessment. In this regard, an important process is the current state analysis ("CSA") which provides Toronto Hydro with an assessment of the major assets that are currently installed in the system.

Key parameters that are collected from and integrated into the CSA include:

- Asset registry data (e.g. nomenclature, asset class/sub-class, installation type);
- Asset quantity data;

- Asset condition assessment and demographic data; and
- Asset-class and system-wide replacement value based upon useful life criteria.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system to establish the core asset registry data and asset demographics. Through the development of the CSA, Toronto Hydro can quickly establish key information on major assets including condition, age, useful life, and replacement value.

There are two key outputs from the CSA process:

- **Asset demographic data:** Provides a yearly break down for the number of asset units installed along with their respective costs. This data set allows Toronto Hydro to establish the percentage of assets past useful life.
- **Condition demographic data:** Indicates Health Scores (and subsequent Health Index bands) for applicable asset classes and sub-classes, helping to flag higher risk assets within the system from a condition perspective.

This process establishes foundational data that is used in the long-term and short-term planning processes for distribution assets. Figure 7 illustrates the inputs, elements, and outputs associated with the CSA.

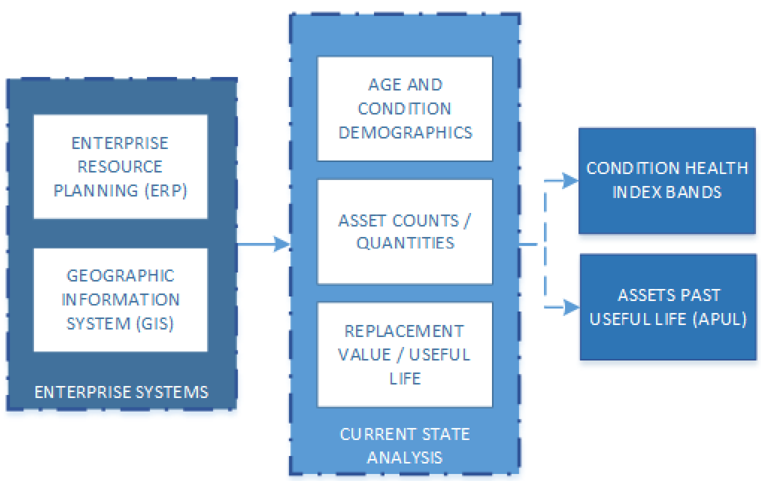


Figure 7: CSA Process

In addition to asset specific data, Toronto Hydro assesses emerging needs and challenges of the system by evaluating additional risk factors. For example, Toronto Hydro evaluates the available and forecasted capacity of the system to identify capacity-related risks. As discussed in Section D1.2.1.2 as well as D3.3 above, this is done through load forecasting, reviewing scenarios such as the Future Energy Scenarios ("FES"), load and generation connections forecasting, as well as the Regional Planning Process. These processes enable Toronto Hydro to identify spare capacity and anticipate areas of potential constraints as a result of developments and load growth or reductions in different areas of the City. The Regional Planning Process is an important input for distribution system planning (specifically, station plans), as a result of infrastructure planning on a regional basis to better predict system challenges. Capacity Planning is discussed in more detail in Exhibit 2B, Section D4.

Toronto Hydro accounts for emerging needs as they arise in the system. This could be as a result of asset specific information (legacy assets and configurations, safety and environmental concerns relating to a specific type of asset), climate and weather impacts, technological advances, or available capacity to connect customers. The processes identified in this section are used to assist system planners with developing well informed plans that consider the various risks and challenges mentioned above in order to meet the needs of the system.

The results of the Asset Needs Assessment that formed the basis of Toronto Hydro's system investment plan for 2025-2029 are discussed in Exhibit 2B, Section E2.2.

D3.4.3 Portfolio Planning

The Portfolio Planning process produces program-level expenditure plans in alignment with the utility's asset management objectives. As part of Portfolio Planning, asset-related data from the CSA is combined with system-wide information regarding known challenges facing the distribution system in order to assess asset and system needs. Toronto Hydro relies on the analyses and decision support tools (as discussed in Section D3.2 and Section D3.3) to identify assets or areas with high levels of risk requiring intervention. When identifying and proposing portfolios, the utility also accounts for customer feedback resulting from regular customer engagement activities. Customers' needs and preferences are a key input for determining the investments needed to meet customers' expectations on service.

During the Portfolio Planning process, Toronto Hydro develops investment requirements for managing system assets and challenges, based on the condition of assets, age of assets, risks of asset failure, legacy assets within the system, load growth, and opportunities for modernization. The analysis of assets from both a risk and outcomes perspective during the investment planning process ultimately drives the development (and management) of capital programs, which are detailed in Exhibit 2B, Sections E5 to E7 of the DSP.

The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system. Toronto Hydro assesses its entire asset base in light of the risks discussed above. Assets that are past their useful life or in HI4 ("material deterioration") or HI5 ("end of serviceable life") condition are identified, as defined earlier in Section D2.2. Information regarding historical failures is combined with asset level information to better understand not just the probability of failure but the cause of failure as well. The configuration of the system is also analyzed in these cases to see if inherent design limitations are contributing to increased risk for specific assets or types of configurations in the system. For example, the presence of legacy assets, such as paper-insulated lead-covered ("PILC") cable and asbestos-insulated lead-covered ("AILC") cable, can often result in safety or environmental consequences. The severity of the risk posed by these assets is considered when deciding whether to invest in replacing these assets proactively and also in determining the correct pace of replacement. Ultimately, similar types of interventions with the same driver are aggregated into capital programs. The expected probability of failure and historical reliability information also drives the requirement for Reactive and Corrective capital in order to address the level of failures observed.

In addition, Toronto Hydro must consider work that must be accomplished as part of its mandate (e.g. pursuant to the Distribution System Code), and responsibility as a Local Distribution Company ("LDC"). These investments may be demand driven or initiated by a third-party, and are categorized as System Access programs, such as Customer Connections or Externally Initiated Plant Relocations.

Program expenditures are then aggregated to create a total investment plan for any given year. The impact of the cumulative investment plan on outcomes is considered to ensure that investments are made in a prudent manner that manages the various risks discussed in this section while providing value for the customer.

Toronto Hydro considers, on an aggregate level, the impact of various investment levels on outcome measures (for example, SAIFI, SAIDI, and System Capacity). By forecasting the performance of key outcome measures over the long-term under proposed investment levels, Toronto Hydro is able to understand trade-offs in investing in different programs and at different investment levels. This initial investment requirement represents a bottom-up needs assessment by system planners for the optimal expenditure levels required.

Various investment strategies are reviewed and deliberated internally before selecting a proposed approach. Once investment plans are reviewed, the information becomes a foundational input as part of other corporate business planning activities.

For more details on how these activities unfolded for the 2025-2029 Capital Expenditure Plan, see Exhibit 2B, Section E2.

D3.4.4 Portfolio Reporting

The IPPR process also creates a feedback loop that provides information about program level completion and historical work executed in each program.

Information is reported on an individual project basis and includes the project's total spending and assets replaced or installed in any particular program. This data is broadly used within Toronto Hydro in assessing the status of capital programs as a result of the completed projects. This was first outlined in Section D1.2.1.3 under the discussions regarding the IPPR process. The aggregate of project-specific expenditures and asset units installed indicates how much of the capital investment program has been executed relative to the target for the program. Reporting is an important component in the process as it provides feedback on Toronto Hydro's ability to execute proposed investments as well as an opportunity to revisit and adjust plans for the upcoming years if needed.

D3.4.5 Project Development and Prioritization

As part of short-term planning activities, once capital investment programs are established, as explained in Section D3.4.3, assets and issues identified for each program are addressed as part of discrete capital projects. As explained within Section D1.2.2, the scope and project development process includes four phases: (i) identification of specific needs; (ii) assessment of options; (iii) high level scope creation; and (iv) refinement of scope and cost estimation.

During the first two phases, investment planners analyze discrete portions of the distribution system, such as a neighbourhood or street, in order to identify projects that align with the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues, or other necessary day-to-day operational investments), enterprise data is used to identify assets at a discrete level so that investment opportunities are identified, risk is managed, and outcome objectives are achieved. For example, with respect to a program driven by failure risk, enterprise systems and the analyses discussed in Section D3.2 can be utilized to identify the program-level prioritized assets that align with this driver.

In addition, ACA results can be used to identify those assets in HI4 and HI5 bands. Reliability analytics can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs, nameplate information or localized data (as per the load forecasting process, discussed in Section D3.3) may be used to identify specific investment needs.

When an investment need for a project within a particular investment program has been confirmed and verified, phase three of the Scope and Project Development is carried out. A project draft, also known as scope of work, is produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in the installation of new assets in a new configuration. Examples include the conversion of overhead plant rear lot to underground plant in order to minimize outages caused by external factors, or the re-configuration of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into an annual capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, Toronto Hydro documents the scope of work to be performed and produces a high-level cost estimate to execute the project. Efficiency savings can be realized by addressing the prioritized assets and issues along with adjacent assets that also require intervention as a single project, as opposed to replacing these assets individually on a reactive basis. Toronto Hydro is undertaking a multi-year project to implement its EAIP system. Projection information will be stored within this system, along with key supporting data points and impacted assets, to enable value calculations by applying Toronto Hydro’s custom Value Framework. A project study may also be divided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign. The project draft then undergoes a quality control assessment, before proceeding into the project finalization stage through the planning supervisor.

Once approved, the project is further refined both in terms of the scope of work as well as the cost estimate. As part of this process, field visits are conducted to ensure accuracy of the data that is used, obtain additional information and measurements, and to understand other potential risks for construction. Permitting requirements are also dealt with at this stage. This process results in a more refined project draft and cost estimate.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program. Once the projects are finalized, they will be scheduled for execution based upon the Project Management and Execution process outlined in D1.2.3. Each project is scheduled based upon relative priority, resource availability, and system constraints (e.g. contingency issues or summer switching restrictions). Factors that impact project scheduling and execution include:

- Project scope and requirements, for example, asset delivery to locations and complexity of the site;
- External constraints such as coordination with external groups;
- Permitting and moratoriums;
- Supply chain;
- Coordination between other projects; and
- Resource balancing.

As part of scheduling, investment planners and program managers meet to discuss the relative priority of the various projects to establish the capital work program for execution in a given year. Toronto Hydro is currently on track to begin leveraging the optimization capabilities of its EAIP tool for the vast majority of its investment programs by the beginning of the 2025-2029 period. The implementation of EAIP will allow Toronto Hydro to implement and adopt a consistent and robust measure of value (and risk) for improved asset management decision making.

As part of the execution process, the detailed project design and estimate are produced to finalize capital investment spending levels. To address any required change to the project cost, schedule, or scope of work, Toronto Hydro maintains a change management and governance process. This process provides visibility across all relevant stakeholders on major project changes, requiring approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects.

Asset Condition Assessment

Methodology Update and 2022 Results Analysis

1. Introduction

Asset Condition Assessment ("ACA") involves the use of condition inspection data to estimate the remaining serviceable life of physical assets. Utilities periodically inspect physical assets to monitor signs of degradation (e.g. visible corrosion) that can lead to asset failure. Inspection data on its own is useful in identifying and prioritizing assets for maintenance, refurbishment, or replacement. An ACA augments inspection data for assets by processing such data to arrive at a health score that represents an asset's condition and proximity to end of serviceable life.

This report highlights changes to Toronto Hydro's approach to ACA since implementing the Condition Based Risk Management framework ("CBRM") in 2017[1] and summarizes the ACA results for 2022 year-end ("YE"), including projections to 2029YE.[2] For convenience, the 2017YE results are also produced. Section 2 summarizes the key changes Toronto Hydro implemented to its ACA methodology, including continuous improvement efforts to implement additional components of the CBRM.

Section 3 highlights the ACA results for 2017YE, 2022YE, and projections for 2029YE, which are also summarized in Exhibit 2B, Section D3, Appendix B. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes. ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like-new condition to the stage where asset degradation is significant enough to warrant urgent attention. This information supports the development of longer-term investment plans and serves as an important input into Toronto Hydro's 2025-2029 DSP. For more details on how Toronto Hydro leverages ACA within its Asset Management framework, please refer to Section D3.

2. Summary of Enhancement to ACA Methodology

Within CBRM there are three main aspects: Asset Health, Asset Criticality, and Asset Risk, with the latter being a combination of the first two. Each of these can be expressed as an index, which indicates relative value, or a specific value (probability or monetary). As part of its initial implementation in 2017, Toronto Hydro focussed on Asset Health expressed through the Health Index, which fully replaced and improved upon its previous asset health methodology. Since then, Toronto Hydro continues to review and refine the existing methodology, as well as build on it by adopting incremental components of CBRM, including condition-driven Probability of Failure ("PoF") on the Asset Health side and Consequence of Failure ("CoF") on the Asset Criticality side. Toronto Hydro retained EA Technology to help guide this process and to review the improvements as well as identify opportunities for continuous improvement. EA

[1] See EB-2018-0165, Exhibit 2B, Section D, Appendix C for details.

[2] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

Technology's review of Toronto Hydro's current ACA models and results is included in Exhibit 2B, Section D3, Appendix C.

Table 1 below summarizes the material refinements introduced to the Asset Condition Assessment Methodology.

Table 1: Material Refinements to ACA Asset Models

Refinement	Description	Impacted Asset Models
Normal Expected Life	Toronto Hydro implemented changes to the normal expected life within the ACA models of impacted asset classes to reflect revisions to useful life values in light of its updated Depreciation Study completed by Concentric Inc.[3]	• Underground Transformer (Submersible, Padmount, & Vault) • Air Insulated Pad-mount Switches • Network Protectors • SCADAMATE switches • Circuit Breaker (Air Blast, Air Magnetic) • Station Power Transformer
Wood Pole Asset Model Refinement	The condition factor for the Wood Pole model was refined based on Toronto Hydro's field experience to better reflect specific condition parameters. Specifically, the level of granularity was increased within the models for the following condition parameters: Pole Base Rot was separated into: • Pole Base Rot (At/Below Ground Level) • Pole Base Rot (Above/ Level) Pole Void was separated into: • Pole Void (Wood Loss) • Pole Void (Hollow Heart/Pockets Present) Bird/Animal Damage: • Calibrated factor for "Extensive" condition observation Pole Separation was separated into: • Pole Separation (Cracks) • Pole Separation (Pole Top Feathering)	• Wood Pole

[3] Available at Exhibit 2A, Tab 2, Schedule 1, Appendix D. While the Depreciation Study was intended primarily to determine useful lives for financial purposes, Toronto Hydro leveraged insights gained from that exercise to review and revise as appropriate its 'engineering' or 'planning' useful lives.

Continuous Improvement:

In addition to the refinements and enhancements above, Toronto Hydro is in the process of implementing condition-driven PoF curves for applicable asset classes. For a given asset, the PoF per annum can be calculated with the following cubic relationship:

$$PoF = k \cdot \left(1 + (H \cdot C) + \frac{(H \cdot C)^2}{2!} + \frac{(H \cdot C)^3}{3!}\right)$$

Where:

- k, C – Asset class specific constants
- H **–** Asset health score unless $H \geq 4$, 4 otherwise

Historical failure data in conjunction with the calculated health scores are used to determine PoF parameters on an asset class basis.

In addition to the PoF, Toronto Hydro intends to implement the Consequence of Failure ("CoF") and Criticality aspects of CBRM, co-ordinating and aligning with Value Framework developments for System Renewal investments as part of its implementation of an Asset Investment Planning ("EAIP") system. For details on Toronto Hydro's Value Framework developments, please see Section D1.2.1.1 and D3.2.1.1.

3. Health Score Results

Tables 3-5 and Figures 1-3 provide a summary of the health index distribution for each asset class by count and percentage:

- Historical, as of the end of 2017;
- Current, as of the end of 2022
- Future, projected for year end 2029

The health bands are defined as per table 2 below:

Table 2: Health Index bands and definitions

<table>
<tr><th>HI Band</th><th>Lower Limit of Health Score</th><th>Upper Limit of Health Score</th><th>Definition</th></tr>
<tr><td>HI1</td><td>≥ 0.5</td><td>< 4</td><td>New or good condition</td></tr>
<tr><td>HI2</td><td>≥ 4</td><td>< 5.5</td><td>Minor deterioration; in serviceable condition</td></tr>
<tr><td>HI3</td><td>≥ 5.5</td><td>< 6.5</td><td>Moderate deterioration; requires assessment and monitoring</td></tr>
<tr><td>HI4</td><td>≥ 6.5</td><td>< 8</td><td>Material deterioration; consider intervention</td></tr>
<tr><td>HI5 (Current Health)</td><td>≥ 8</td><td>≤ 10</td><td rowspan="2">End of serviceable life; intervention required</td></tr>
<tr><td>HI5 (Future Health)</td><td>≥ 8</td><td>≤ 15</td></tr>
</table>

Table 3: Summary of Health Index Distribution as of year end 2017.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	8,112	1,162	1,350	398	89
4kV Oil Circuit Breaker	36	4	123	24	
AirBlast Circuit Breaker	15	9	206	1	3
Air Magnetic Circuit Breaker	145	90	247	21	53
Oil KSO Circuit Breaker	10	7	11	11	1
SF6 Circuit Breaker	130	6	18	3	3
Vacuum Circuit Breaker	578	46	13	2	29
Network Protectors	1,086	185	319	74	26
Overhead Gang operated Switches	854	27	76	3	9
Air Insulated Padmount Switch	404	20	73	30	45
SF6 Insulated Padmount Switch	402	-	2	-	6
SCADAMATE Switches	1,084	1	26	-	8
Air Insulated Submersible Switch	755	79	27	7	-
SF6 Insulated Submersible Switch	353	14	7	3	19
Station Power Transformers	83	77	61	13	8
Network Transformers	1,334	255	166	60	7
Padmount Transformers	5,547	656	283	113	18
Submersible Transformers	7,816	588	271	172	55
Vault Transformers	6,807	4,315	450	214	45
Underground Vaults (Combined)	1,017	186	72	12	29
ATS Vaults	8	-	-	-	-
CLD Vaults	21	-	-	-	-
CRD Vaults	9	-	1	-	-
Network Vaults	322	120	63	11	29
Submersible Switch Vaults	115	5	-	-	-
URD Vaults	542	61	8	1	-
Wood Poles*	63,526	7,354	29,779	5,687	722

*Please note that Wood Pole results are re-calculated based on the refinement to the Wood Pole asset model highlighted in Table 1 above.

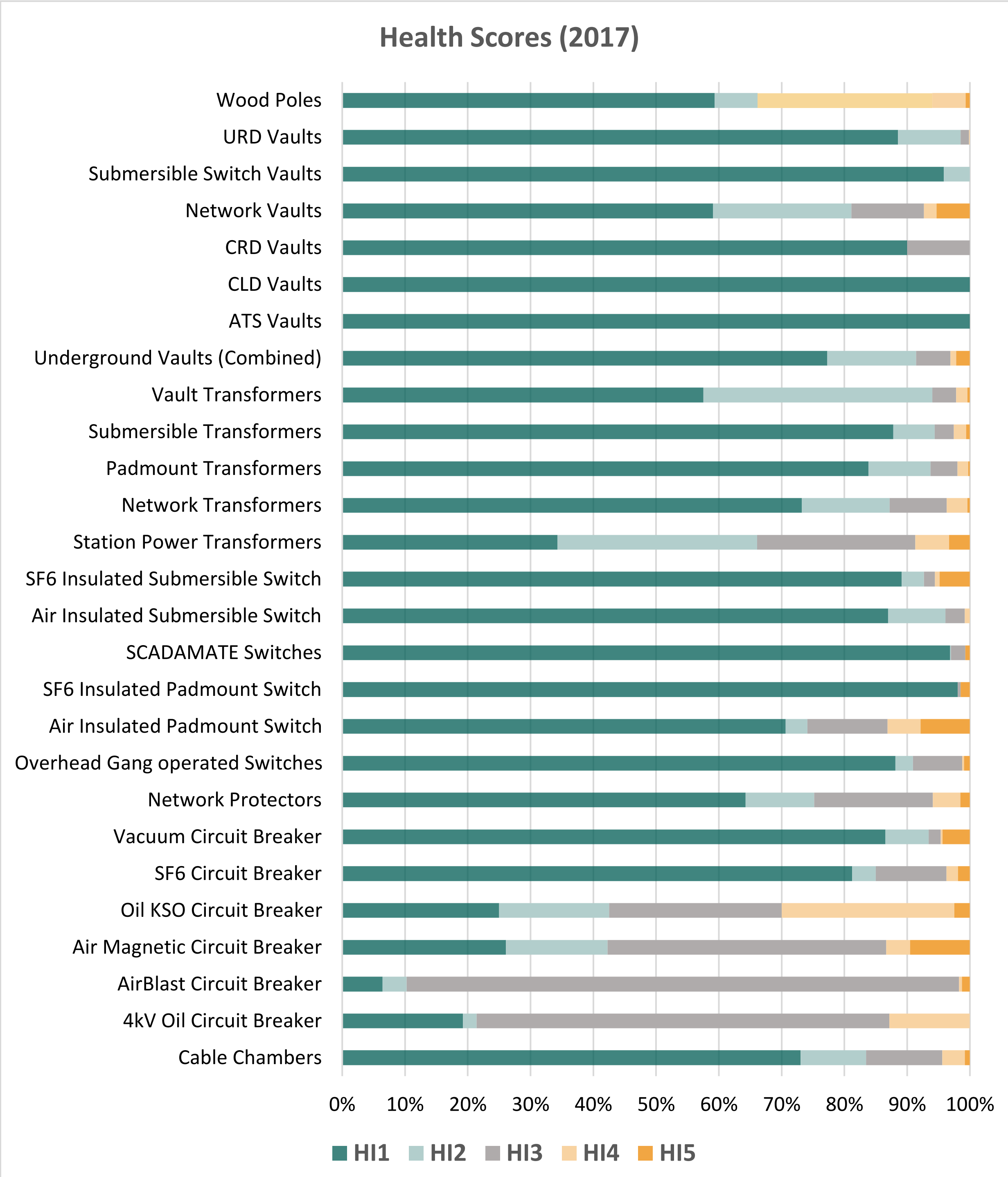
Table 4: Summary of Current Health Index Distribution as of year end 2022.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,640	1,346	2,079	462	130
4kV Oil Circuit Breaker	4	-	53	-	1
AirBlast Circuit Breaker	2	1	137	8	8
Air Magnetic Circuit Breaker	61	47	357	2	27
Oil KSO Circuit Breaker	1	13	9	-	-
SF6 Circuit Breaker	121	6	2	4	-
Vacuum Circuit Breaker	803	12	10	-	-
Network Protectors	1,342	129	233	21	3
Overhead Gang operated Switches	659	98	88	10	13
Air Insulated Padmount Switch	359	4	64	24	29
SF6 Insulated Padmount Switch	663	-	-	1	16
SCADAMATE Switches	1,078	9	66	4	13
Air Insulated Submersible Switch	720	183	67	7	-
SF6 Insulated Submersible Switch	437	18	15	7	10
Station Power Transformers	87	66	12	8	-
Network Transformers	1,370	244	61	40	3
Padmount Transformers	5,142	1,085	527	233	24
Submersible Transformers	8,120	699	162	133	47
Vault Transformers	6,799	3,869	571	247	11
Underground Vaults (Combined)	870	164	49	53	47
ATS Vaults	5	1	-	1	-
CLD Vaults	20	2	-	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	225	110	44	46	45
Submersible Switch Vaults	70	3	-	-	-
URD Vaults	542	45	5	6	2
Wood Poles*	68,288	7,566	21,073	8,950	509

Table 5: Summary of Future Health Index projected for year end 2029.

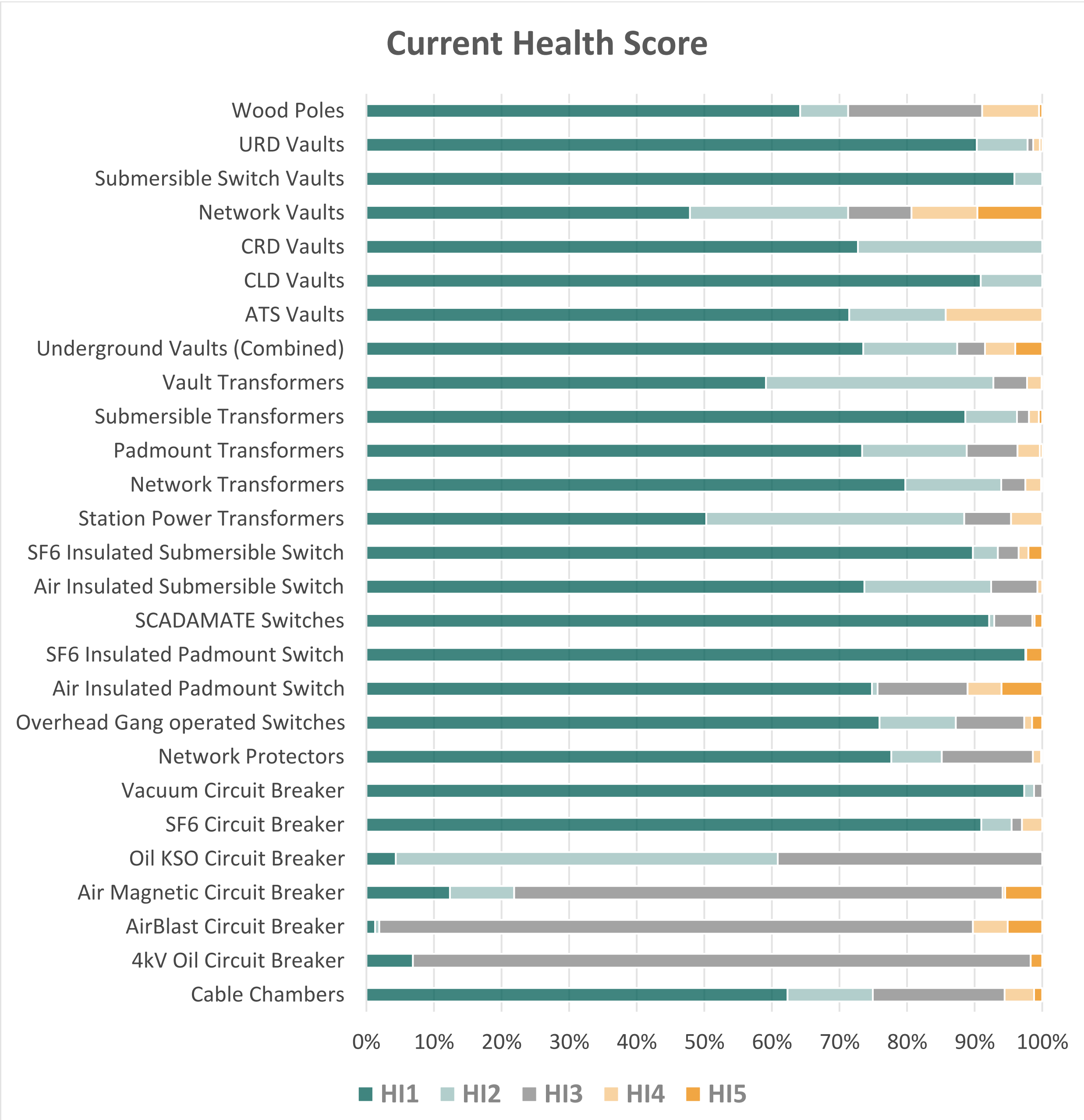
Asset Class	Health Score;				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,015	1,026	2,503	535	578
4kV Oil Circuit Breaker	4	-	29	24	1
AirBlast Circuit Breaker	2	-	97	43	14
Air Magnetic Circuit Breaker	11	50	41	361	31
Oil KSO Circuit Breaker	1	-	8	14	-
SF6 Circuit Breaker	93	28	4	2	6
Vacuum Circuit Breaker	786	17	10	12	-
Network Protectors	1,298	40	56	187	147
Overhead Gang operated Switches	517	106	111	91	43
Air Insulated Padmount Switch	320	18	13	16	113
SF6 Insulated Padmount Switch	663	-	-	-	17
SCADAMATE Switches	724	65	69	149	163
Air Insulated Submersible Switch	667	53	152	90	15
SF6 Insulated Submersible Switch	419	26	9	6	27
Station Power Transformers	82	11	60	12	8
Network Transformers	1,243	111	215	87	62
Padmount Transformers	4,451	542	887	595	536
Submersible Transformers	7,330	642	635	240	314
Vault Transformers	5,220	1,668	3,595	587	427
Underground Vaults (Combined)	848	101	83	52	99
ATS Vaults	4	1	1	-	1
CLD Vaults	20	-	2	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	207	92	34	47	90
Submersible Switch Vaults	68	4	1	-	-
URD Vaults	541	1	45	5	8
Wood Poles*	60,308	8,350	5,570	24,464	7,694

Figure 1: Health Score Distribution by Asset Class as of year end 2017



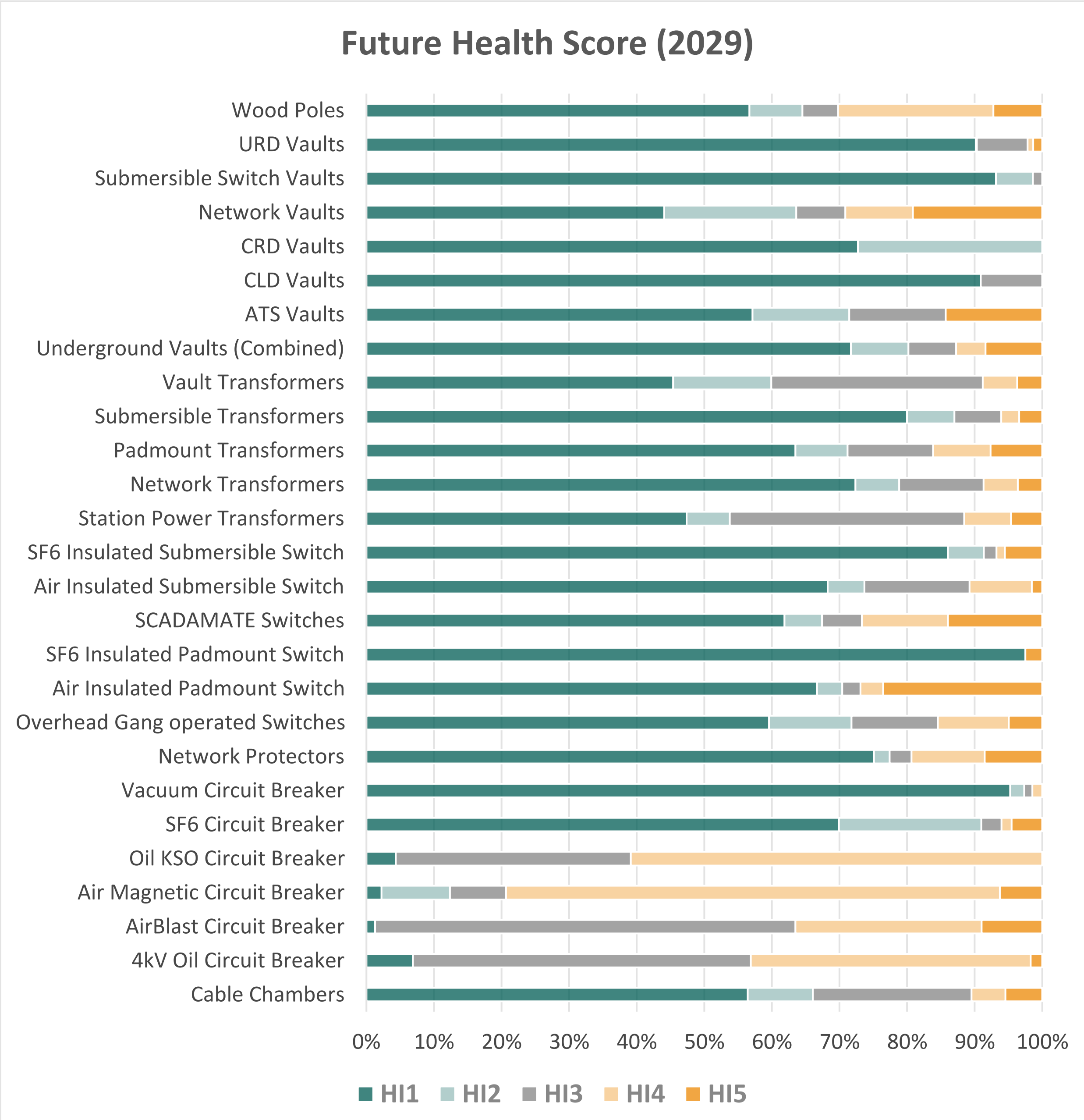
HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 2: Current Health Score Distribution by Asset Class as of year end 2022

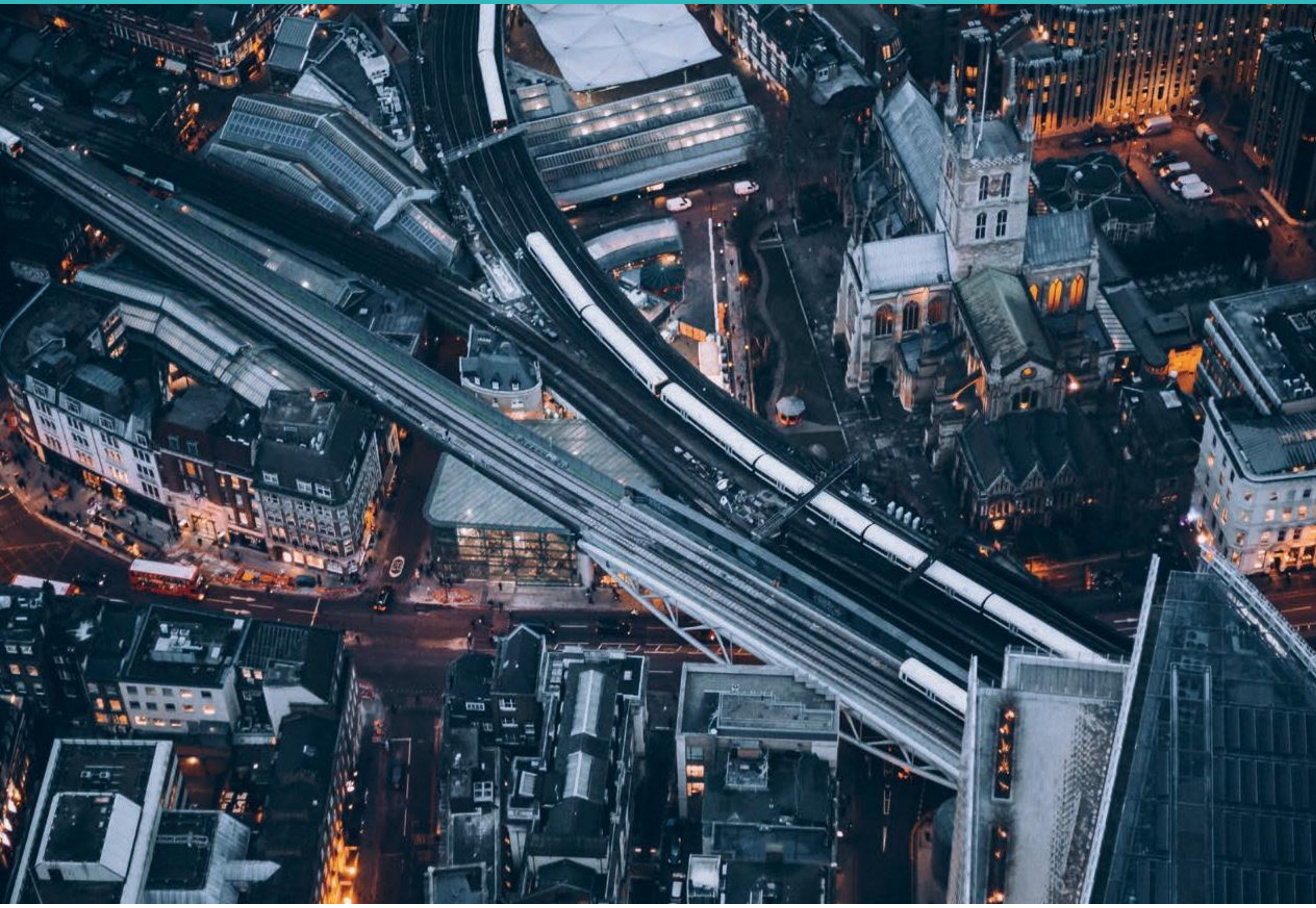


HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 3: Future Health Score Distribution by Asset Class for year end 2029



HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;



REPORT

Review of ACA Modelling Enhancements and Customisations

Private and Confidential

Prepared for: Toronto Hydro-Electric System Ltd.

Report No: EA22383
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1. Introduction

Toronto Hydro-Electric System Limited (THESL), is a wholly owned subsidiary of Toronto Hydro Corporation, and is the largest municipal electricity company in Canada. Its electrical distribution network comprises of over 13,500km of underground cables and 15,000km of overhead lines that distribute around 19% of the electricity consumed in the province of Ontario to approximately 790,000 customers located within the city of Toronto and its surrounding area.

THESL is recognised within the region as a sustainable electricity company and is committed to develop its in-house capabilities through continuous improvement. Within the discipline of asset management, this has included an undertaking to implement a series of Asset Condition Assessment (ACA) models based on the Common Network Asset Indices Methodology (CNAIM).

CNAIM, or the Common Methodology as it is often referred to, is the approach used by Distribution Network Operators (DNOs) in Great Britain to report asset health and criticality as part of their regulatory reporting requirements. EA Technology has supported the GB Distribution Network Operators through the development of CNAIM and has worked with the majority of the GB DNOs to implement the methodology and embed it within their organisations.

In 2017/8, THESL, supported by EA Technology, successfully completed a project to develop, build and commission a suite of enhanced CNAIM-based ACA models to support their endeavours pertaining to the adoption of an advanced condition-based approach for electrical system planning, the strategic evaluation of both capital investments and day-to-day maintenance activities.

Since 2021 THESL has embarked on the process of enhancing its implementation of the ACA methodology, including implementation of probability of failure (PoF) and consequences of failure (CoF). EA Technology was engaged to provide guidance and feedback on the derivation of appropriate inputs to the PoF and CoF calculations.

This latest engagement involves an independent review of the ACA implementation, enhancements and customisations made by THESL since 2018. Consideration has been given to the general outputs of the enhanced THESL ACA models, alignment with the core principles of the CNAIM methodology, and the generally accepted industry practices for condition and risk-based asset management within an electrical distribution arena.

1.1 Scope and Objectives

The agreed scope of work to be undertaken by EA Technology comprises of three main activities:

- Task 1: a review of the changes and enhancements THESL has made to its health score methodologies since 2018.
- Task2: a review of the current and future health score outputs for three asset classes selected by THESL.
- Task 3: a review of THESL's implementation of probability of failure, consequence of failure, asset criticality and risk.

The objective of this undertaking is to provide assurance to THESL that the enhancements and customisations introduced into the ACA models since 2018 align with the core principles of the CNAIM methodology.

This piece of review work has been undertaken remotely and is limited to the materials supplied by THESL which, where necessary, have been supported by clarifications made via video conference meetings.

2. Definitions

The following terms and abbreviations are contained within this document:

ACA	Asset Condition Assessment
BOSCEM	Basic Oil Spill Cost Estimation Model
CAD	Canadian Dollar
CBRM	Condition Based Risk Management
CI	Customer Interruption
CMI	Customer Minutes of Interruption
CNAIM	Common Network Asset Indices Methodology
CoF	Consequence of Failure
DNO	Distribution Network Operator
GB	Great Britain
HI	Health Index
HS	Health Score
ITIS	Interruption Tracking Information System
kV	Kilovolt
PoF	Probability of Failure
PCB	Polychlorinated Biphenyl
SF_6	Sulphur Hexafluoride
THESL	Toronto Hydro-Electric System Ltd.
UG	Underground
WSIB	Workplace Safety and Insurance Board

3. THESL ACA Model Portfolio

Following completion of the initial ACA model development project in 2018, THESL currently operate and maintain a total of 21 asset condition assessment models. These models are listed in Table 1 below.

Table 1 Breakdown of THESL ACA models by Asset Type

Asset Type	THESL ACA Model / Asset Class
Switchgear	Air Insulated Pad-mounted Switches Air Insulated Submersible Switches Air Magnetic Circuit Breakers Air Blast Circuit Breakers Network Protectors Oil Circuit Breakers Oil KSO Circuit Breakers Overhead Gang Operated Switches SCADAMATE Switches SF_6 Circuit Breakers SF_6 Insulated Pad-mounted Switches SF_6 Insulated Submersible Switches Vacuum Circuit Breakers
Transformer	Network Transformers Pad-mount Transformers Station Power Transformers Submersible Transformers Vault Transformers
Overhead Line	Wood Poles
Civils	Cable Chambers UG Vaults

The initial ACA model development project was immediately followed by an independent review which was completed by specialist asset management consultants from EA Technology with expert asset condition modelling knowledge. This review recommended that changes to the ACA model calibration and its associated processes were made in order to disassociate the ACA model outputs from established THESL tactical asset management practice, which would allow the core CNAIM methodology to provide a more strategic view of the asset portfolio.

Following a short series of specialist asset management training sessions, and with the support provided by EA Technology, THESL successfully revised the calibrations such that the ACA models were less reliant upon computational caps and collars designed to ‘force’ health score calculations subject to the identification of user-specified asset deficiencies obtained through programmes of inspection. It is understood that the ACA models were internally reviewed by THESL to ensure real-world alignment before the models were ‘frozen’ prior to the start of preparations for the 2018/2019 regulatory filing.

4. ACA Asset Health Score Review

4.1 Introduction

Task 1 has involved a review of THESL's ACA model inputs and calibrations to identify any changes that have been made to the ACA Health Score derivation methodology since the models were previously frozen in 2018.

The review has considered:

- the full range of ACA models contained within Table 1 above;
- variation(s) in information sources, data validation, and input data fields which feed the ACA models' computational algorithms;
- changes to data processing approach, algorithm format, and calculation sequence;
- the process of ACA Health Score calibration employed by THESL;
- any revisions to calibration values (including condition caps and collars) and, where appropriate;
- THESL's rationale and justification for change.

4.2 Review of Findings

The independent desktop review has considered the information provided by THESL, from which it appears that THESL's asset management function remains comfortable with the vast majority of the previously frozen 2018 ACA models.

Information exchanged between THESL and EA Technology has confirmed that THESL have explored the possibilities for further ACA model development behind the scenes. Consideration has been given to potential solutions pertaining to geographic, situational and locational influences thought to directly affect asset health. However, difficulties have been experienced with a number of potential avenues explored in terms of data quality, availability, and ease of data maintenance. These issues are considered to affect the repeatability of ACA modelling over time, and therefore THESL have elected not to include this data enhancement until such time that a more enduring solution can be found. A summary table of ACA model modifications is provided in Table 2 below.

THESL have confirmed that there have been no notable changes in asset inspection and maintenance programmes since the last review, and that input data sourcing, processing and validation approaches remain unchanged since 2018, and therefore no changes to the number of model input data fields have been made.

Table 2 Summary of ACA Methodology Changes 2018 to Present

	Changes to ACA Model							
THESL ACA Model / Asset Class	Information Source?	Source Data Validation?	Model Input Data Fields?	Computational Algorithm Format?	Calculation Sequence?	Calibration Process?	Calibration Value?	Caps or Collars?
Air Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
Air Insulated Submersible Switches	No	No	No	No	No	No	No	No
Air Magnetic Circuit Breakers	No	No	No	No	No	No	No	No
Air-Blast Circuit Breakers	No	No	No	No	No	No	No	No
Cable Chambers	No	No	No	No	No	No	No	No
Network Protectors	No	No	No	No	No	No	No	No
Network Transformers	No	No	No	No	No	No	No	No
Oil Circuit Breakers	No	No	No	No	No	No	No	No
Oil KSO Circuit Breakers	No	No	No	No	No	No	No	No
Overhead Gang operated Switches	No	No	No	No	No	No	No	No
Pad-mounted Transformers	No	No	No	No	No	No	No	No
SCADAMATE Switches	No	No	No	No	No	No	No	No
SF_6 Circuit Breakers	No	No	No	No	No	No	No	No
SF_6 Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
SF_6 Insulated Submersible Switches	No	No	No	No	No	No	No	No
Station Power Transformers	No	No	No	No	No	No	No	No
Submersible Transformers	No	No	No	No	No	No	No	No
UG Vaults	No	No	No	No	No	No	No	No
Vacuum Circuit Breakers	No	No	No	No	No	No	No	No
Vault Transformers	No	No	No	No	No	No	No	No
Wood Poles	No	No	No	Yes	No	No	Yes	No

From a computational perspective, the high-level desktop review has found that modification to the THESL ACA Health Score methodology has only taken place within a single asset class, namely wood poles. For all other asset classes, the previously established input information sources, data validation techniques, computational algorithms and calculation sequences are understood to remain unchanged. THESL stand by the results produced by these models and have stated that their approach to ACA model verification, review and calibration continues to be directly aligned with earlier guidance and direction provided by EA Technology and continues to remain effective. Therefore modification of these ongoing ACA models and their associated maintenance processes has been deemed unnecessary.

Within the Wood Pole ACA model, the identified changes are considered to represent a significant indication of asset management maturity development and evidence of THESL's adoption and engagement with advanced asset management techniques. The modifications made to the wood pole ACA model are considered to be comparatively minor in nature, as they relate specifically to the observed condition point factor derivation. However, this act of refinement demonstrates the existence of functioning closed loop feedback channels within the organisation's asset management system, and proof that they are being effectively used.

Wood pole structures owned and operated by THESL are understood to be subject to a lengthy, 10 year inspection cycle, of which only a proportion of the asset population are condition assessed in any one year. This approach to asset inspection is commonplace as, if implemented correctly, the condition of other assets within the wider population can be either implied or inferred, reducing resource requirements and operational costs. However, this inspection approach also has a significance during ACA methodology and model development, as traditionally asset managers raise concerns about the ability of field data to accurately reflect the condition of physical assets which have not been inspected for a long period of time. Hence, the development of ACA models in such circumstances often takes place using only a proportion of the wood pole asset population and/or inspection information – which is neither unusual nor unexpected during asset modelling solution development.

Following the completion and commissioning of ACA models for asset classes with long inspection periods, over a period of time updated asset inspection data is collected, processed, and used to inform health score calculation. Gradually inference and implied condition are replaced with real condition data which enables the generation of more accurate asset health profiles.

ACA model outputs need to be subjected to regular review in order to reduce the risk of model drift – where the results produced by condition assessment modelling systems start to vary such that they gradually no longer accurately reflect the "real-world" physical asset condition. The key control to protect against drift being either re-calibration or model refinement.

As an organisation, THESL have acquired vital essential modelling experience with their updated ACA methodology and solution and are understood to have conducted a series of regular ACA model output reviews and tests. It is through this analysis that THESL have identified the early signs of conservative model drift, in which the health score profiles generated by the ACA system relating to wood poles are being recognised as being too pessimistic. i.e. are being represented by a higher health score than would be expected.

Evaluation of the ACA results has identified examples of field inspectors discovering multiple minor pole defects, small pole voids or low levels of pole rot at a wood pole structure being interpreted by ACA models as causing potential for an unacceptable increase in probability of failure, thereby directing intervention. THESL recognise such identified attributes as potential concerns; however, within the existing wood pole management framework, they would not provide a sufficient justification for significant capital intervention.

In part, this situation has been caused by inexperience and unfamiliarity pertaining to health score definition and interpretation and is likely to have been as a result of an overstatement of specific observed condition point influence during the model's initial development and calibration. The resulting effect being a natural misalignment of health score values during a period of bedding in and condition data refreshment.

EA Technology understand that the condition data input 'Pole Rot' was initially a combination of three data fields (Surface Rot Below Ground Level, Surface Rot at Ground Level, and Surface Rot Above Ground Level) collected during routine inspection. The data input into the ACA model was the worst of the recorded inspection results, with a commonly applied calibration. Following a review of the model outputs, THESL identified that the resultant condition factor was providing an excessive influence within the health score derivation. By separating these originally combined input data fields and using individual calibration tables, a higher degree of influence control can be obtained. THESL's ACA model refinement now treats the observed condition points 'Pole Base Rot (At/Below Ground Level)' and 'Pole Base Rot (Above Ground Level)' separately.

In the 2018 wood pole model, the observed condition points 'Pole Void' and 'Pole Separation' were treated in a similar way to 'Pole Rot'. The worst of two recorded inspection results formed the input into the ACA model, again, with a commonly applied calibration. Following the review of the results from the model outputs, THESL have separated the inputs as shown in Table 3 and included individual calibration tables to increase the modelling effect of moderate hollow hearts/pockets presence and reduce the modelled effect of pole structures found to possess slight cracks when compared to structures suffering with slight pole top feathering.

Table 3 Observed Condition Inputs for Pole Voids and Pole Separation in 2018 and 2022 Models

ACA Model 2018	ACA Model 2022
Pole Void	Pole Void (Wood Loss) Pole Void (Hollow Heart/Pockets Present)
Pole Separation	Pole Separation (Cracks) Pole Separation (Pole Top Feathering)

As part of the review process, the calibration associated with 'Extensive Animal damage' has also been revised (increased slightly) to align with the identified deficiencies outlined above.

In order to facilitate the changes outlined above, the computational data processing algorithms used to determine the Pole Rot, Pole Void and Pole Separation condition factors must have been modified to accept the additional data fields and calibration inputs. However, algorithms associated with the calculation of the Observed Condition Factor retain the standard MMI (Maximum and Modified Increment) technique used in CNAIM and is therefore considered to remain consistent with the underlying principles of the Common Methodology.

EA Technology consider that this type of ACA model refinement is only to be expected and would form part of the natural organic asset condition modelling process as organisations such as THESL adopt and embrace more modern, advanced asset management approaches. As in the case outlined above, any such model or methodology revision would be expected to include detailed internal evaluation, review and, where necessary, aspects of model re-calibration. Evidence of this having taken place exists in the fact that the observed condition factor 'Animal Damage' has been adjusted to ensure result consistency.

5. Review of Current and Future ACA Health Score Outputs

Task 2 has involved a desktop review of the ACA model outputs for the following asset classes as selected by THESL: Wood Poles, Network Transformers and Submersible Transformers. The data extract files have been provided in MS Excel format and include all data inputs, intermediate calculations (e.g. initial health score, condition modifiers, health score caps and collars), current health score values and predicted health scores for future years.

Observations on the implementation of the CNAIM methodology, the calibration settings and the current and future health index profiles for wood poles, network transformers and submersible transformers are provided in Sections 5.1 to 5.3. As part of the review, the intermediate calculations, including derivation of observed and measured condition modifiers and ageing rates have been verified as being consistent with the CNAIM methodology.

5.1 Wood Poles

The wood pole model comprises 106,386 assets ranging in age from new to more than 45 years old. The initial health score of each asset is derived from its age and the normal expected life of the asset class (45 years). More than 25% of the population (29,469 poles) have an initial health score of 5.5 driven by the age of the asset. This seems to be quite high and is likely to be due to the calibration of the Normal Expected Life (see Section 7.1).

The model includes both observed and measured condition modifiers as indicated in Table 4.

Table 4 Wood Pole Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	Worst Condition of:	HS Collar(s)	Modifier	HS Collar(s)
Pole Leaning	-	Yes	Pole Strength	Yes
Bird/Animal Damage	-	Yes	Shell Thickness	Yes
Pole Based Rot	At/below ground level Above ground level	Yes		
Pole Separation	Cracks Pole top feathering	Yes		
Pole Void	Wood loss Hollow heart/pockets present	Yes		

Health score collars have been applied to all of the modifiers such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's established practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for wood poles as calculated using the ACA methodology is shown in Figure 1.

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* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4.

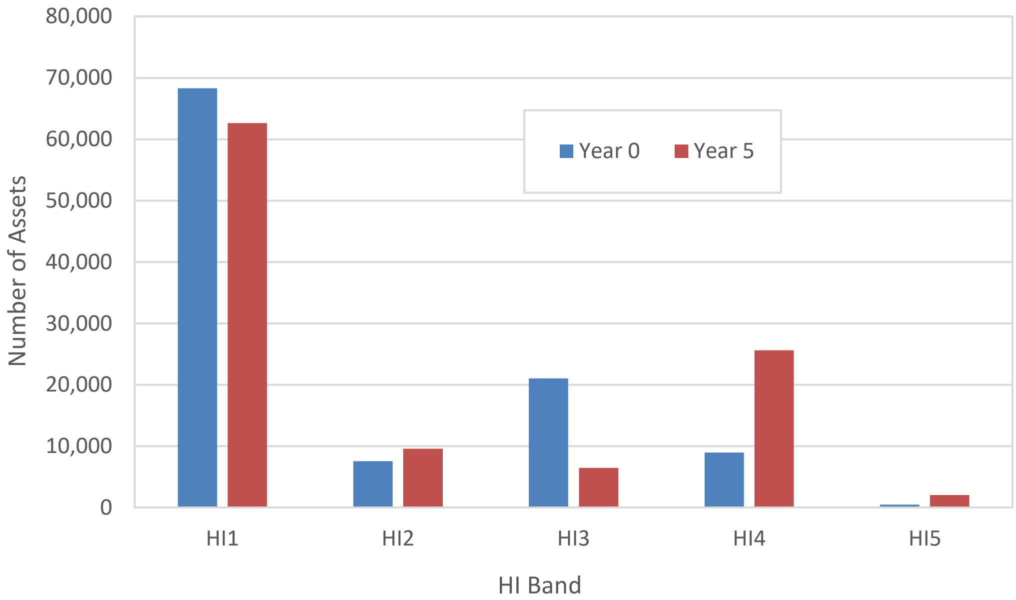

Figure 1 Wood Poles: Current and Future (Year 5) Health Index Profile

The current health index profile seems reasonable given the age profile and condition of the asset population. The 'spike' in the number of wood poles in the HI3 band is driven by assets that have ages beyond the expected life of 45 years.

Just over 2% of the asset population have health score values set through condition collars, mainly due to moderate pole separation (cracks and pole top feathering). This shows a considered approach to the setting of condition collars to identify assets with issues requiring intervention.

The CNAIM methodology includes an additional (reliability) modifier to reflect any issues or observations that are not reflected in the observed and measured condition modifiers. THESL have used this methodology feature in the wood pole model and applied a collar of 7.25 to assets that have been confirmed to be in a poor condition by inspectors in the field. This is considered to be an appropriate use of the reliability modifier mechanism to directly impact asset health where information is available.

Figure 1 shows a slow movement of assets from HI1 to HI2 and HI3 over the next 5 years, with a more rapid progression from HI3. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.2 Network Transformers

The network transformer model comprises 1,718 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the normal expected life of the asset class (35 years) and a measure of how hard the asset is working (the ratio of peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and it is understood that a default is applied to any transformers with a calculated utilisation of more than 200%. This is a valid approach where known inaccuracies and inconsistencies exist in the data sources.

There are 229 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced normal expected life due to the high duty that the asset is experiencing. This proportion of assets with a maximum initial score of 5.5 is reasonable given the age profile and high utilisation of some of the transformers.

The model includes both observed and measured condition modifiers as indicated in Table 5. .

Table 5 Network Transformer Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	HS Collar(s)	Comments	Modifier	HS Collar(s)
External Condition of Tank	Yes	Stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body	Partial Discharge	Yes
Oil Leaks	Yes	Stronger factors and collars for leaks from the base than for leaks not from the base	Temperature Readings	Yes
Connection Condition	No	-		
Primary Switch Condition	Yes	-		

A number of health score collars have been applied such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's existing practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for network transformers as calculated using the ACA methodology is shown in Figure 2.

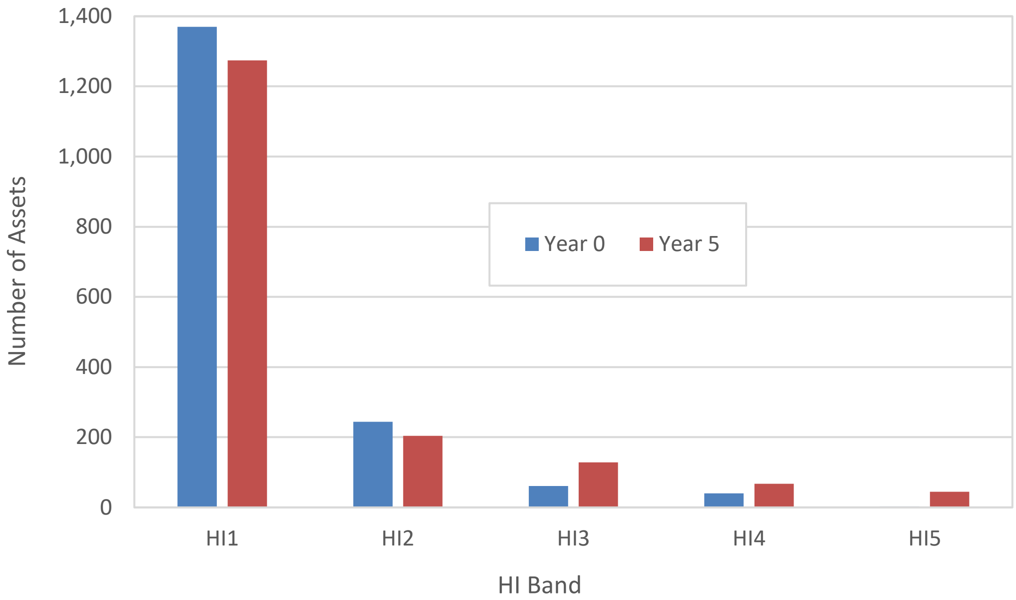

Figure 2 Network Transformers: Current and Future (Year 5) Health Index Profile

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

The current health index profile looks reasonable given the age and condition of the asset population. A small number of assets (44) have health score values set through condition collars, mainly due to corrosion issues and / or significant oil leaks. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 2 shows the assets moving slowly through the health index bands over the next 5 years. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.3 Submersible Transformers

The submersible transformer model comprises 9,161 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the expected life of the asset class (30 years) and a measure of how hard the asset is working (the ratio peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and have applied a default to any transformers with a calculated utilisation of more than 150%. This is a valid approach where data inaccuracies exist.

There are 568 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced expected asset life due to the high duty that the asset is experiencing. This proportion of assets with a maximum initial score of 5.5 is reasonable given the age profile and utilisation of some of the transformers.

The submersible transformer model includes three observed condition modifiers as follows:

- External condition of tank (with stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body).
- Oil leaks (with stronger factors and collars applied to leaks from the base than to leaks not from the base).
- Connection condition. No condition collars are applied.

The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned to the principles of the CNAIM methodology.

The current and future (year 5) health index profile[*] for submersible transformers as calculated using the ACA methodology is shown in Figure 3.

[*] The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

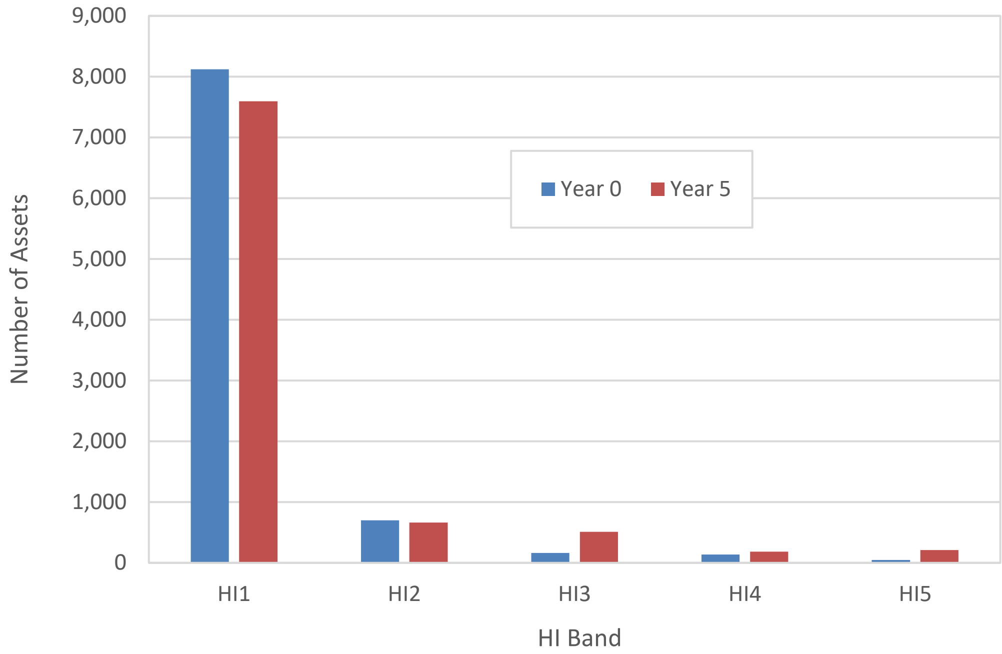

Figure 3 Submersible Transformers: Current and Future (Year 5) Health Index Profile

The current health index profile would appear to be reasonable given the age and condition of the asset population. A small proportion of assets (around 3%) have health score values set through condition collars, mainly due to oil leaks and corrosion issues. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 3 shows the assets moving slowly through the health index bands over the next 5 years. Again, this seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.4 General Comments

The high-level assessment of THESL's ACA models for wood poles, network transformers and submersible transformers has found the logic, factor evaluation and calculation sequence to align with the principles of the CNAIM methodology. In particular, the results show:

- heath index profiles indicative of an asset population that appears to be maintained and generally in a good condition;
- the proportion of health score results that have been 'forced' by health score collars seems reasonable for the asset populations; and
- acceleration of assets to the HI4 band appears reasonable and aligns with established THESL asset management thinking and existing business processes.

EA Technology understand that THESL are continuing to work on improving data quality. This review has highlighted the following data anomalies:

- The network transformer and submersible transformer models include some unrealistically high utilisation values. THESL have recognised the potential for data inaccuracies and applied default duty factors above threshold transformer utilisations (understood to be 200% in the network transformer model and 150% in the submersible transformer model). This is a valid approach and provides a straightforward way of eliminating questionable data and potentially overstating the heath score and ageing rate for the affected assets.

- It is understood that more than one data source is being used for network transformer utilisation and operating temperature. Some of this data looks suspect, with a number of units apparently delivering 3 times name plate rating having reported maximum operating temperatures in the region of 40°C. This is clearly a data discrepancy and may possibly understate the measured condition modifier and hence the health score of affected assets.
- Wood pole inspection frequency is understood to be conducted on a rolling 10 year cycle. However, the data extract file provided contains condition data collected either in or before 2012. The review has also found that for a small proportion of structures within the population, the nature of the structure material is either unknown, unclear, or 'wood'. Such data gaps and discrepancies are not unusual in asset populations of this size and should reduce over time as more data is collected, resulting in more granular health index profiles.

6. Review of THESL's Probability of Failure, Consequence of Failure, Asset Criticality, and Risk Implementation

Task 3 has involved a review of THESL's ACA derivation of asset probabilities of failure, the determination of consequence of failure values from their broader Value Framework, and the approach to the application of criticality factors in order to calculate risk. Due to the recognised differences in operating and regulatory environment between Ontario and Great Britain, this review has not focused on establishing whether THESL have been able to duplicate the CNAIM methodology's calculation sequence. Instead, it has determined whether the implementation is reasonable and aligned with generally accepted industry practices and the underlying principles of the Common Methodology.

6.1 THESL Failure Mode Definitions

The CNAIM methodology considers functional failures[*] in the derivation of probability of failure (PoF) and consequences of failure (CoF). These relate to the inability of an asset to adequately perform its intended function and are therefore not solely limited to failures that result in an interruption to supply. Three failure types are included within the CNAIM methodology (incipient, degraded, and catastrophic) and these are used in the evaluation of both PoF and CoF.

THESL have defined three failure modes depending on the asset deterioration stage and corresponding remedial action as listed in Table 6. These failure modes have been applied in the ACA methodology for the derivation of probability of failure and consequence of failure values. The three failure modes align with both THESL's established practices and the principles of the CNAIM methodology and are considered to be appropriate for the evaluation of asset PoF and CoF.

Table 6 THESL Failure Mode Definitions

Failure Mode	Description
Incipient	A failure associated with early-stage asset degradation. Such failures can be resolved through the undertaking of planned corrective action which may require an outage.
Degraded	A failure associated with advanced asset degradation, for which reactive repair would be expected to only have a limited effect. Such failures are likely to result in planned asset replacement.
Outage	A failure associated with advanced asset degradation, which will often result in a sustained outage until unplanned reactive works have been completed.

[*] Functional failures considered in Common Methodology relate only to those failures directly resulting from the condition of the asset itself; failures of function due to third party activities are not included.

6.2 Probability of Failure

The CNAIM methodology uses a standard relationship between health score and PoF based on a modified cubic relationship as follows:

$$PoF = k \cdot \left(1 + (H \cdot c) + \frac{(H \cdot c)^2}{2!} + \frac{(H \cdot c)^3}{3!}\right)$$

where:

PoF = probability of failure per annum

H = a variable equal to health score, unless health score ≤ 4 and then H = 4

k & c = constants (for a given asset category)

The value of c fixes the relative values of the probability of failure for different health scores (i.e. the slope of the curve) and k determines the absolute value.

Within CNAIM, c has been set to the same value (1.087) for all asset categories and has been selected such that the PoF for an asset with a health score of 10 is ten times higher than the PoF of a new asset.

The value of k has been set for each asset category covered by the CNIAM methodology by considering the number of functional failures in the different failure modes recorded in Great Britain over a five year period.

As the values of k are averaged across the DNOs within Great Britain, it is appropriate for THESL to derive representative values of k for each asset class from the asset populations and known failures in each of the failure mode categories defined in Table 6. During the engagement on THESL's continued CNAIM/CBRM implementation in 2021/22, EA Technology explained the approach to determining k and provided THESL with an Excel spreadsheet* showing a worked example of how to derive a 'composite' value of k from multiple failure modes.

THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. During the initial review of the probability of failure curves it was found that the calculated PoF values were excessively high for some asset classes. Following a trouble-shooting session with EA Technology asset management specialists, THESL revisited the definition of incipient failures to exclude failures that could be classed as operational defects.

The k values provided by THESL for each of their asset classes have been reviewed as part of Task 3 and the revised definition of incipient failures gives PoF curves that seem credible across all asset classes. It is not meaningful to compare THESL's k values with those in CNAIM given the proportions of each failure type comprising a 'composite' failure, the asset populations and differences in asset management practices; however, the process undertaken to derive representative values of k is considered to be robust and the corresponding PoF curves appear reasonable.

6.3 Consequences of Failure

All of the ACA models developed by THESL include the four consequence categories associated with asset failure that are included within CNAIM: Network Performance, Safety, Financial, and Environmental. Sections 6.3.1 to 6.3.4 below consider each of the defined consequence categories in turn.

* *Derivation of k.xlsx*. Excel spreadsheet provided to THESL by email on 15 April 2021.

The Consequences of Failure methodology in CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on an organisation's experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of the specific asset. These factors are generally referred to as criticality factors and are discussed further in Section 6.4.

6.3.1 Network Performance Consequences

In the CNAIM methodology, the Network Performance Consequences of Failure take into account the way in which electrical system operators restore customer supplies following unplanned events and asset failures. THESL's ACA approach to Network Performance CoF appears to directly align with CNAIM with the consideration of three distinct phases of supply restoration that reflect a staged restoration process:

- Phase 1 makes allowance for system redundancy, auto-change-over schemes, intelligent networks, and SMART grid technologies which either prevent reportable supply interruptions or those that act independently and automatically to restore healthy electrical system components before any interruption (duration) is required to be recorded as part of the governing regulatory system.
- Phase 2 is associated with system re-configuration via switching operations in an effort to firstly minimise, and secondly provide a means of isolation for non-serviceable network sections whilst reconnecting more connected customer supplies.
- Phase 3 typically involves activities designed to either repair or replace failed power system assets thereby enabling the integrity of the original system to be restored.

Quantification of Network Performance Consequences of Failure usually involves analysing the number of customer supplies affected by supply interruptions caused by asset failure along with their associated outage durations. Alternatively, system operators need to establish a robust mechanism through which reductions in available system capacity and capability can be determined. For convenience, this quantification often works in terms of domestic supply equivalence and is generally more easily understood.

THESL's ACA quantification of Network Performance CoF is formed using two component parts reflecting the costs of customer interruptions (CIs), and the on-going cost of electrical supply outage duration (CMI). The sum of the blended CI and CMI costs is then multiplied by the probability of interruption before the application of any criticality factors.

THESL have carried out an in-depth evaluation of the information held within their Interruption Tracking Information System (ITIS) relating to historical asset failure, unplanned outage, and emergency response activities. Following the completion of a statistical analysis of the data, THESL have been able to both identify and quantify network performance consequences for each of the failure modes under consideration.

This review has found that in terms of secondary transformers, the Network Performance CoF (outage duration) determinations for fuse replacements, component repairs, and the restoration of supplies through the adoption of alternative 'temporary solutions' straightforward to understand and apply. Transformer replacement is not as intuitive, as the relationship between transformer location and assignment of the closest resource (yard) availability is not as immediately obvious for those unfamiliar with the nuances of the organisation.

Quantification of asset failures are presented in terms of the number of connected customers supplies affected and takes account of the likelihood of electrical protection system success through a statistical determination of the number of multiple supply interruption occurrences on a per failure mode basis. Consideration should be given to extending this form of evaluation into network configurations that possess higher security of supply standards such as n-1 where asset failures do not necessarily result in unplanned outages.

Both CoF calculation stages employ THESL system performance data and financial values which provide a solid basis for defence if challenged. Although highly dependent upon system control data processes, THESL's implementation of this aspect of the ACA modelling process appears to align with the underlying philosophy of CNAIM where asset failures result in unplanned outages.

6.3.2 Safety Consequences

THESL's ACA models have been designed to generate consequence of failure values for events that have the potential to result in loss of life, cause reportable lost time accidents, or inflict damage to a third party's property. It is understood that the approach taken is universally applied across the entire suite of THESL's ACA models.

When considering asset failures which result in fatality, the ACA models calculate the safety consequences of failure differently depending upon whether or not the deceased is a direct employee of the utility. In the instance that direct employees are fatally wounded, the consequence values are based upon figures associated with the Ontario Workplace Safety and Insurance Board (WSIB). The consequence values used to represent fatalities involving members of the general public are also based on WSIB figures and are further supplemented by financial values outlined in the WorkSafe BC Incident Cost Calculator.

Safety consequences of failure associated with lost time incidents are derived using an Exposure Hour Methodology based upon THESL data, with WSIB costs for direct employees of the utility and Government of Canada figures for events not involving employees.

At the present time, safety consequences associated with damage to third party property are not included within the total safety consequence value determination.

The consequence values used within the ACA models are summarised in Table 7 below.

Table 7 ACA Safety Consequences of Failure Inputs

Safety Consequence Category	Probability of Consequence Occurrence	Consequence Value
Fatality	Values set as per CNAIM	Direct Employee \$1.6m CAD Member of the Public \$1.784m CAD
Lost Time Accident	0.00815%	Direct Employee \$15k CAD Member of the Public \$6k CAD
Damage to Third Party Property	No data available	Defaulted to \$0 CAD

The approach taken to determine the Safety Consequence of Failure values is considered to directly align with the principles outlined within the CNAIM methodology. They appear to be based upon sensible information sources, and as they comprise of recognised industry and government standard figures, would be considered both reasonable and defendable if challenged.

6.3.3 Financial Consequences

The Financial Consequences of Failure in THESL's ACA models are determined by defined asset failure modes as outlined in Section 6.1:

- *Incipient failures*. Financial consequences are based upon the financial figures used to determine the regulatory Rate Case Filing and real-world OPEX expenditures obtained from THESL's historical data.
- *Degraded failure* financial consequences are based upon THESL's standardised unit cost information combined with THESL's previous experience of managing and undertaking capital works.
- *Outage failures*. Financial consequences have been derived from analysis of THESL's historical emergency response figures.

The inclusion of standardised unit costing information is considered to be an appropriate route to determine the Financial Consequences of Failure within the ACA methodology as the values incorporated are both recognisable and defendable in equal measure.

6.3.4 Environmental Consequences

THESL's ACA models consider four different aspects of environmental impact when calculating the Environmental Consequences of Failure. These relate to loss of oil containment, the release of SF_6 insulant gas, the potential effects of asset failures resulting in fire, and the generation of waste.

The environmental consequences for oil and SF_6 releases are treated in the same way. For each failure mode under consideration, an evaluation has been made to determine the likelihood of insulant release; this is currently supported by a worst-case scenario assumption that a total loss of insulant occurs. The product of these values is then multiplied by an environmental contamination/release cost which is used to derive individual environmental consequences.

The environmental consequences associated with fire centre around the potential to ignite oil and are again calculated by first determining a likelihood of fire event occurrence, a representative means of quantifying the impact of any fire event (typically via the conversion to equivalent volume of CO_2 emitted), and the identification of a per unit emission cost.

Fire event probability has been sourced from THESL's Interruption Tracking Information System to identify the number of asset failures that involved fire events as a proportion of the total number of asset failures experienced for each asset class. THESL have then used asset records to determine how much oil assets contain, before using standardised government figures to calculate a financial value for the environmental consequences.

It is understood that THESL are, at the time of writing, not able to accurately determine a satisfactory mechanism through which waste disposal costs can be accurately identified. This is thought to be due in part to the variability of scrap materials on the open market which offsets the total cost of asset decommissioning and disposal. Within the ACA models, therefore, the financial value pertaining to the environmental consequences from generation of waste have been set to a default value such that they do not contribute to the overall Environmental Consequences of Failure calculation.

A summary of the Environmental Consequences of Failure inputs is shown in Table 8 below.

Table 8 ACA Environmental Consequences of Failure Inputs

Category	Calculation Input	Information Source
Oil	Probability of release occurrence	THESL ITIS and Oil Spill Incident Records
	Assumed Volume released (per event)	Assumed complete loss of all asset oil. Source THESL asset records.
	Unit cost (per litre)	Basic Oil Spill Cost Estimation Model (BOSCEM) by the US Environmental Protection Agency
SF_6	Probability of release occurrence	THESL ITIS and EHS data
	Assumed Volume released (per event)	Assumed that all asset SF_6 is lost. Source THESL asset records.
	Unit cost (per kg)	Government of Canada CO_2 emission cost scaled to SF_6 equivalent \$1,195/kg CAD
Fire	Probability of failure causing fire	Derived from THESL's ITIS data
	Volume of fire (CO_2 emission)	Total oil volume taken from THESL asset records converted to CO_2 emission value.
	Unit Cost (CO_2 emission)	Government of Canada \$50/ton CAD
Waste	Waste disposal costs	Not currently used. Defaulted to \$0 CAD

The ACA approach to environmental CoF quantification is regarded as being aligned with CNAIM, and is considered to employ sensible, defendable unit costs and probabilities against each relevant consequence category. The difficulties THESL are experiencing in relation to determining average asset disposal costs are understood, as is the intention to continue to search for a workable solution.

6.4 Asset Criticality

The CoF methodology within CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on DNO experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of each asset. These factors are generally referred to as criticality factors.

THESL have followed a similar approach to the CNAIM methodology and considered the application of criticality factors in each of the four consequence categories as discussed in Sections 6.4.1 to 6.4.4 below.

6.4.1 Network Performance Criticality

THESL's ACA models contain a Customer Sensitivity Factor that can be employed to reflect circumstances where the impact of unplanned power outages is increased due to customer reliance on electricity (e.g. customers with health issues such as a dependency on dialysis machines). This criticality factor is currently defaulted to unity, and therefore does not influence the Network Performance Consequences of Failure. THESL are understood to be considering the most appropriate approach to applying the Customer Sensitivity Factor and may introduce it in the future.

For a small number of asset classes, THESL are understood to have introduced an additional criticality factor which considers the accrued labour hours recorded against asset intervention.

Statistical analysis performed by THESL during evaluation of consequences of failure has identified differences in response times depending on where assets are located. For example, there are increased logistical challenges in the downtown area which can lead to increased intervention costs as well as potentially extending the duration of supply interruptions.

The exact way in which this modifying factor has been implemented remains unclear, and care must be taken to avoid double counting when determining financial failure costs. However, if proven internally by THESL to be credible, robust, reliable and statistically significant, it is a clever use of the criticality factor facility and would be considered to be completely aligned with the principles which underpin CNAIM.

6.4.2 Safety Criticality

THESL's ACA models make provision for two inputs to the Safety Criticality Factor: a Traffic Factor and a Size Factor. The Size Factor is currently defaulted to unity as THESL do not believe that the severity of any interaction with a failed asset is influenced by its operating voltage, rating, or physical size.

The Traffic Factor has been introduced to reflect how busy the immediate vicinity around the asset is perceived to be. This factor is set using individual asset risk ratings, which have been derived directly from CNAIM guidance. Therefore, ACA models should increase the safety consequences of assets in densely populated areas such as main throughfares, within close proximity to stadiums etc. The magnitude of the Traffic Factor in the ACA models is not known; however, factors in the range from 0.7 to 2.0 would be regarded as reasonable and aligned to CNAIM principles.

6.4.3 Financial Criticality

THESL have identified that significant differences exist in the cost of undertaking asset replacement depending upon the geographic region in which work is required. Two regions, referred to anecdotally as "Downtown" and "the Horseshoe" have been defined, and a Location Factor has been derived from analysis of THESL's historical material and labour costs.

It is understood that the Location Factor is intended to represent some of the challenges associated with resourcing within THESL, and the availability of specific skillsets in particular areas; e.g. lines teams within the city centre region. If set by individual asset class, such an approach can be made to reflect the additional time required for appropriate resources to make their way to asset failures. However, care must be taken not to overinflate the effects of this phenomenon by double counting. It is considered that if a Location Factor is applied globally (i.e. across all ACA models) then there is a possibility that the calculation of financial risk will be distorted.

For those asset classes where the Financial Consequences of Failure are directly linked to the ratings or capacity of the replacement unit, THESL's ACA models include a Size Factor. This enables the costs associated with asset replacement to be scaled to the size of the failed unit. However, as the ACA calculated costs are currently determined using unit costs this feature is set to apply a default value that does not affect the overall Financial Criticality Factor.

6.4.4 Environmental Criticality

The transformer and switchgear ACA models make provision for two inputs to the Environmental Criticality Factor to account for the location of the asset and the presence of polychlorinated biphenyls (PCBs). THESL have identified that oil filled assets that are contaminated with PCBs are more expensive to dispose of when compared to non-contaminated units and have included a PCB Factor. This has been determined from the ratio of the decontamination cost for a metric ton of soil with PCB oil to the decontamination cost for a metric ton of soil with regular (no PCB) soil and is considered to be reasonable and defendable if challenged.

The second input to the Environmental Criticality Factor is the Location Factor which accounts for the additional clean-up costs associated with assets close to water. It has been determined using the BOSCEM method by dividing the environmental cost of asset failure close to water by the environmental cost of asset failure on dry land. This approach is consistent with the principles of the CNAIM methodology and is considered to be reasonable and defendable if challenged.

6.5 General Comments

The review of THESL's derivation of asset probabilities of failure and the determination of consequence of failure values from their broader Value Framework has found the implementation to be logical and to align with the principles and framework of the CNAIM methodology. In summary:

- THESL have incorporated three failure modes into the ACA methodology which have been defined to align with the company's asset management practices. This approach allows THESL to make use of historical data to evaluate failure rates and costs of remedial action in each of the failure modes.
- THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. The analysis undertaken is considered to be robust and the corresponding PoF curves appear reasonable.
- The Consequence of Failure categories used by THESL align with those in CNAIM. These capture the key issues affecting electricity network businesses and can be quantified in terms that allow for monetisation within each consequence category, thus enabling the assessment of risk on a comparable basis across all asset categories.
- Reference Costs of Failure and criticality factors have been derived from recognised data sources and are considered to be relevant to THESL's operating environment.
- The approach to determining reference costs of failure and criticality factors is logical and transparent and, where asset failures result in unplanned customer outages, would be considered robust and defendable if challenged.

7. Discussion and Opportunities for Future Enhancements

THESL have made significant progress in the implementation of their ACA methodology since EA Technology's initial engagement in 2017. They have demonstrated a clear understanding of the concepts behind the GB's Common Methodology and have developed probability of failure curves and consequence of failure values that are appropriate to their operating and regulatory environment whilst retaining alignment with the objectives and principles of CNAIM.

THESL's ACA methodology continues to evolve and it is therefore likely that there will be modifications and enhancements as it 'beds-in' (matures) within the company and more inspection data becomes available to inform the models. This is considered to be a natural process in which the models will improve incrementally over time as the benefits of the approach are realised across the organisation.

Sections 7.1 to 7.4 below summarise the key observations from EA Technology's review of THESL's enhancements and customisations to the ACA methodology. In addition, suggestions for future ACA model developments and/or refinements are provided.

7.1 Health Score Derivation

The principles and philosophy upon which the THESL ACA methodology is based make allowance for asset managers and system operators to draw upon their experience to not only identify, but actually define, sub-groups within asset populations where there are known differences in service lives, asset performance, etc. Examples include:

- *Normal Expected Lives*. Variation in service life by user-identified and defined sub-populations would be expected. This offers the opportunity to enhance the granularity of the health score outputs by setting different Normal Expected Lives by, for example, manufacturer, type, period of manufacture, or material (for wood poles).
- *Duty Factor*. The identification of input data fields which influence asset duty factors should be considered, particularly for switchgear asset classes.

The CNAIM methodology has provision for a Measured Condition Modifier to incorporate information gained from diagnostic tests and measurements into the models. Established condition assessment techniques with empirical relationships include thermography, SF6 condition, oil analysis and partial discharge results. These could be incorporated into existing ACA models to improve the quality of calculated health score results and allow more differentiation between assets.

Following the inclusion of additional condition related inputs, the next natural step in developing asset health indices involves the disaggregation of asset systems into sub-components with their own health score assessment. For example, a Station Transformer could be regarded as a 'composite system' made up of a 'transformer' and separate 'tapchanger'. The health score of the overall transformer asset is then derived from a combination of the health scores of both of these sub-components.

7.2 Health Score Calibration

A small number of ACA models including the SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers have been calibrated to align health score derivations with THESL's tactical asset management practices. Calibration factors are considered to be very aggressive where asset deficiencies are identified, and the models are heavily influenced, if not dependent, upon health score caps and collars.

It is understood that THESL are using this approach at the present time whilst the organisation is building confidence in both the ACA methodology and the outputs from the models. However, the company recognises that this style of model calibration limits the methodology's ability to provide a longer term strategic view of the asset population and intends to review calibration of the condition modifiers in the future.

The underlying CNAIM methodology provides a mechanism such that fundamental indications of empirically proven conditions, perhaps through the existence of Operational Restrictions, may be linked to a Reliability Modifier that directly impacts the asset health score. The use of a Reliability Modifier may offer a potential solution that could help provide a more strategic view of asset classes such as SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers.

7.3 CoF Determination

THESL appear to have good asset information and a wide range of both fault data and asset failure information. These data sources have been used to perform a number of statistical analyses and evaluations that in turn have informed the ACA methodology.

The following areas have been noted during the review process where refinements to the determination of network performance and environmental consequences could be incorporated in the future:

- The existing ACA methodology for the quantification of Network Performance CoF works well for asset failures that result in unplanned outages and electrical supply interruptions. However, for network configurations that contain redundancy or possess higher levels of supply security and may not result in power outages, the current quantification method is likely to understate the system level risk when asset failure occurs. It is recommended that THESL consider how asset failures in such circumstances are quantified and incorporated into the ACA methodology.
- It is understood that there is an absence of reliable data relating to volumes of electrical asset insulant loss resulting from asset failures and the ACA methodology assumes that a total loss of insulant containment will take place as a result of failure. This assumption will hold true for distribution voltage switchgear but is unlikely to be an accurate portrayal of either EHV switchgear with multiple insulant chambers or transformer oils, and therefore is likely to overstate the Environmental Consequences of Failure for such assets. THESL may wish to consider exploring this area in more detail in the future.

The availability of good asset data provides an opportunity for increased accuracy in consequence quantification as even basic knowledge of asset makes, types and designs can be exploited when calculating the financial impacts associated with different types of asset failure. For example, the inclusion of weights and measures stated on manufacturer nameplates could be used to calculate volumes of waste generated and insulant losses; this would provide more granularity to the ACA model outputs.

THESL recognise that they have information sources which could be further exploited to provide additional input data in the derivation of consequences of failure. It is understood that THESL intend to explore this area in the future to refine and enhance the outputs from the ACA models.

7.4 Criticality

When determining the Safety Consequences of Failure, THESL have successfully employed a risk based locational rating referred to as a 'Traffic Factor' as a criticality. Unless they form part of a statutory collection requirement, or are generated by other departments within the business, input parameters like this are valuable, but potentially very expensive to collect and difficult to maintain.

One observation made during this review is the absence of any electrical system criticalities that associate assets with either strategic, commercially sensitive or contingency related circuits. Such criticalities can be used to reflect reductions in system level integrity or possess the potential to cause major supply disruption, and therefore may be subject to differences in either operational or working practices. This may influence both Network Performance and Financial Consequences of Failure.

REPORT

Reimagine tomorrow.

Toronto Hydro-Electric Service Limited: 2018 Value of Service Study

Submitted to Toronto Hydro-Electric Service Limited

January 30, 2020

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1 Executive Summary

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study.

The primary objective of the VOS study was to estimate system-wide outage costs by customer class. The VOS analyses are based on data from three separate surveys (one for each customer class) conducted between January and April, 2018. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.[1]

1.1 Response to Survey

Table 1-1 shows the total number of completed surveys by customer class and the target sample size for each class. The response rate among residential customers was strong, as over 1,000 customers completed surveys either online or via mail, exceeding the target of 800. The response rate for small and medium business customers was lower than expected. Even after increasing the incentive and drawing an additional sample, the total number of completed surveys was only 245. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. For large C&I customers, Nexant scheduled and conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. Nexant was able to follow up after the interview and obtain the necessary data for a number of customers, but was not able to obtain it for 16 of them. The number of complete data points for large C&I was thus 84.

Table 1-1:
Total Number of Completed Surveys by Customer Class

Customer Class	Target	Completed Surveys
Residential	800	1061
Small/Medium Business	800	245
Large Commercial & Industrial	100	84

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

1.2 Outage Cost Estimates

Table 1-2 provides the cost per outage event estimates by customer class. Cost per outage event is the average cost per customer incurred from each outage duration. Given the dynamic survey instrument design which accounted for historical outage onset times, these values represent the average outage cost across all time periods. For a 1-hour outage, large business customers experience the highest cost ($71,808) and residential customers experience the lowest cost ($10.87).

Table 1-2:
Cost per Outage Event Estimates by Customer Class

Outage Duration	Residential ($/Event)	SMB ($/Event)	Large Business ($/Event)	Blended ($/Event)
1 minute	$8.45	$257.38	$32,438	$51.24
1 hour	$10.87	$857.84	$71,808	$131.81
4 hours	$17.56	$2,142.39	$275,182	$381.77
8 hours	$23.35	$4,098.01	$379,381	$626.90
24 hours	$34.53	$8,426.27	$992,647	$1,412.73

Figure 1-1 and Table 1-3 show cost per average kW by customer class. Cost per average kW is the cost per outage event normalized by average customer demand among respondents. This metric is useful for comparing outage costs across segments because it is normalized by customer demand.

Figure 1-1:
Cost per Average kW Estimates by Customer Class

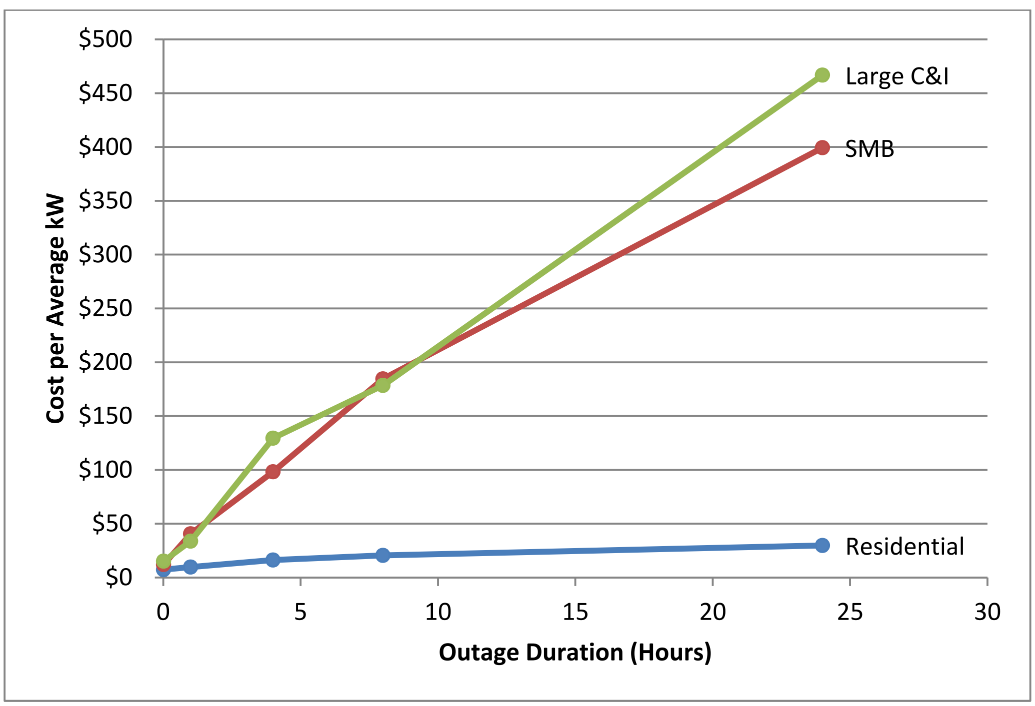


Table 1-3:
Cost per Average kW Estimates by Customer Class

Outage Duration	Residential ($/kW)	SMB ($/kW)	Large Business ($/kW)	Blended ($/kW)
1 minute	$7.31	$12.04	$15.25	$12.80
1 hour	$9.78	$40.68	$33.77	$33.14
4 hours	$16.32	$98.29	$129.41	$94.50
8 hours	$20.53	$184.57	$178.41	$153.83
24 hours	$29.80	$399.42	$466.81	$355.23

Table 1-4 provides the cost per unserved kWh estimates by customer class. Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. At 1-minute, cost per unserved kWh is at its maximum for each region and customer class because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Cost per unserved kWh is useful, as it provides an “apples-to-apples” comparison of how customers value electric service versus what they pay for electric service. For all 4 customer classes and all outage durations, customers place a substantially higher value on an unserved kWh than what they would have paid if that electricity had been delivered. Residential customers experience an outage cost of $5.34 per unserved kWh for a 4-hour outage and $1.75 per kWh for a 24-hour outage, which are lower than the other customer classes, but still substantially higher than what they pay per kWh.

Table 1-4:
Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$616.11	$722.43	$915.28	$768.06
1 hour	$13.21	$40.68	$33.77	$33.14
4 hours	$5.34	$24.57	$32.35	$23.63
8 hours	$3.55	$23.07	$22.30	$19.23
24 hours	$1.75	$16.64	$19.45	$14.80

Table 1-5 provides the duration cost per unserved kWh estimates by customer class. Toronto Hydro uses duration costs for its planning activities. This metric considers the cost of an outage event to be the full cost of the outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The duration cost per unserved kWh is the duration cost per outage event normalized by the expected amount of unserved kWh.

Table 1-5:
Duration Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$0.00	$0.00	$0.00	$0.00
1 hour	$2.94	$28.47	$18.51	$20.26
4 hours	$2.77	$21.62	$28.54	$20.45
8 hours	$2.27	$21.62	$20.39	$17.66
24 hours	$1.32	$16.13	$18.81	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these “blended duration costs.” The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The “Outages Included” column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either “Momentary,” “Planned,” or “Sustained.” Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as “Loss of Supply Events” or could have occurred on “Major Event Days.” These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The “Event Cost” column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The “Duration Event Cost” column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The “Duration” column shows the weighted average outage duration. The two “Hourly Cost” columns show each event cost per hour, or the “Event Cost” columns divided by the “Duration” column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

Table 1-6: Blended Duration Cost Based on Historical Outage Durations

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

Interruption costs for THESL are lower than those of other utilities for which recent studies have been conducted - notably Pacific Gas & Electric (PG&E) in 2012 and Southern California Edison (SCE) in 2019. The shape of THESL's outage cost distributions are similar to those of other studies, but they are lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL’s customer interruption costs.

1.3 Impact of Outage Timing

This study provided useful information on how outage costs vary across season and different times of the day. For the residential and SMB analyses on the impact of outage timing, onset times were aggregated into four key time periods with distinct costs per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

With fewer observations in the large C&I segment, onset times were aggregated into two key time periods as the analysis could not identify clear trends within the more granular time periods used for residential and SMB customers. The two key time periods for large C&I customers were:

- Morning and Afternoon (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

These groups of onset times were further divided among summer and winter for all three customer classes. Figure 1-2 provides the relative cost per outage event estimates for summer and Figure 1-3 provides the estimates for winter, which were derived from the customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each outage cost estimate in Section 1.2 (referred to as the “base value”). As shown in the figure, outage costs for SMB and large C&I customers are sensitive to onset time. SMB outage costs vary from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. SMB outages in summer and winter mornings have the highest percentage increase as these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Large C&I outage costs vary from 59.2% lower during summer nights to 18.3% higher during winter days. Considering that non-residential outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 1-2:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Summer

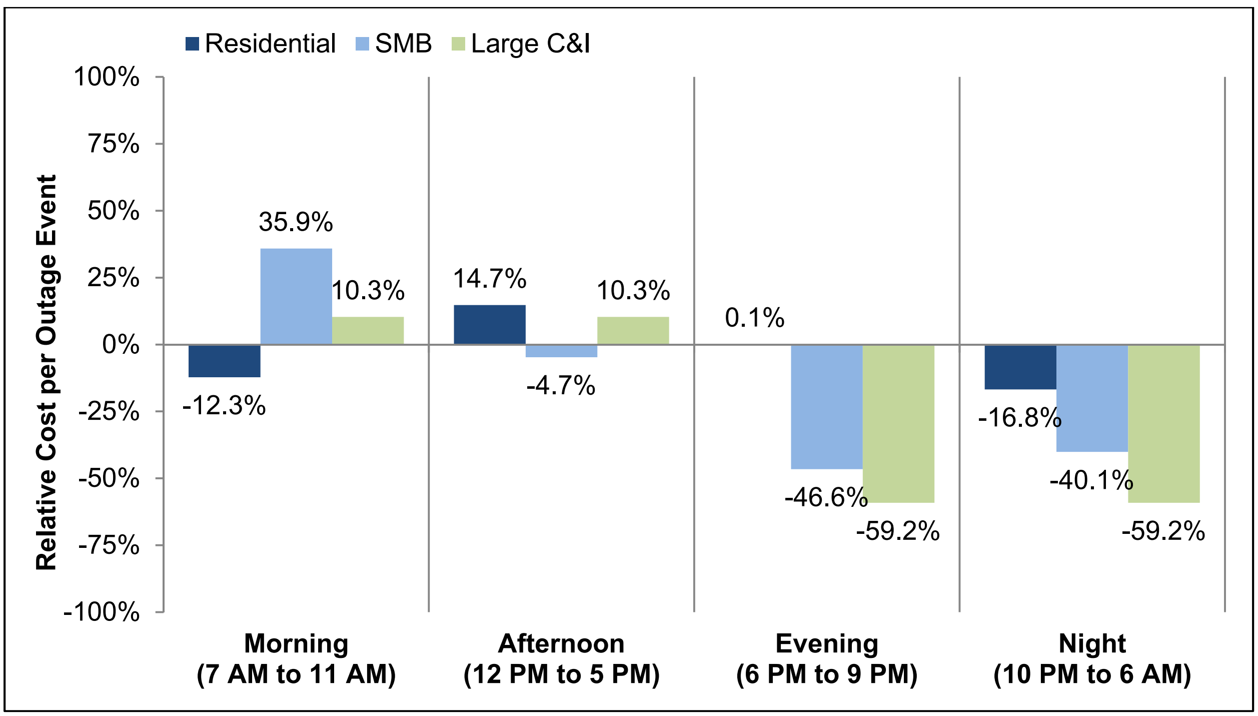
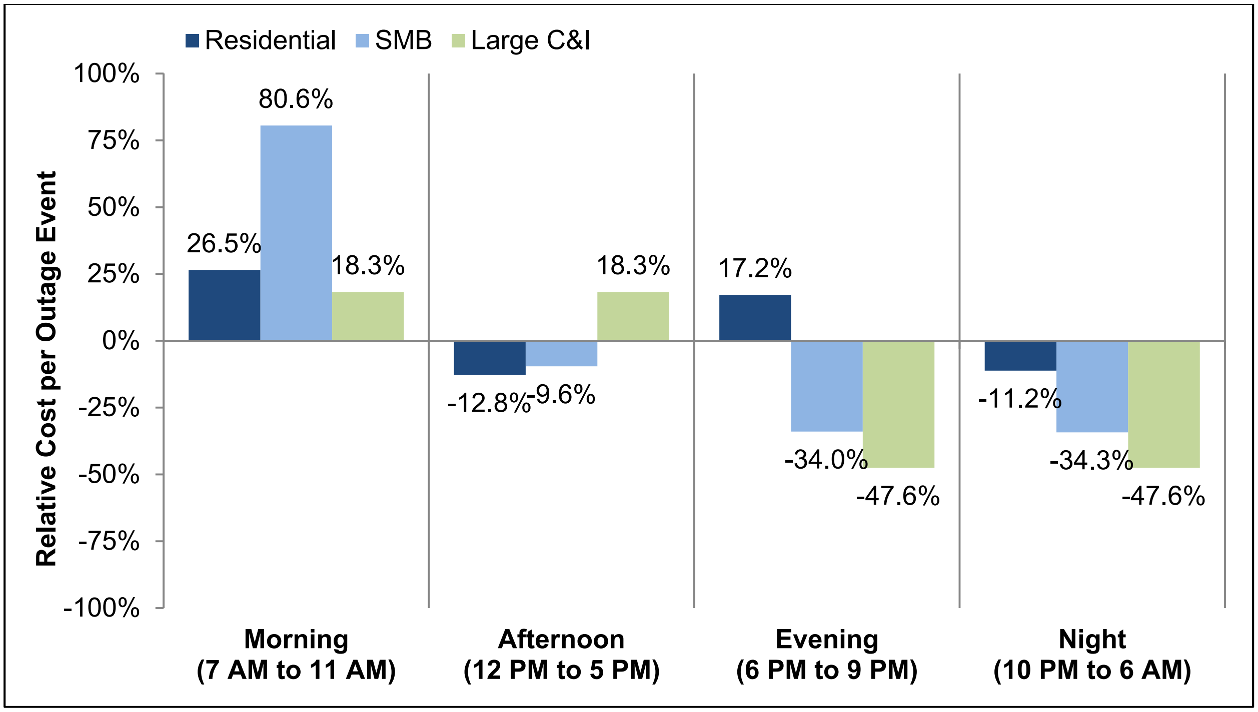


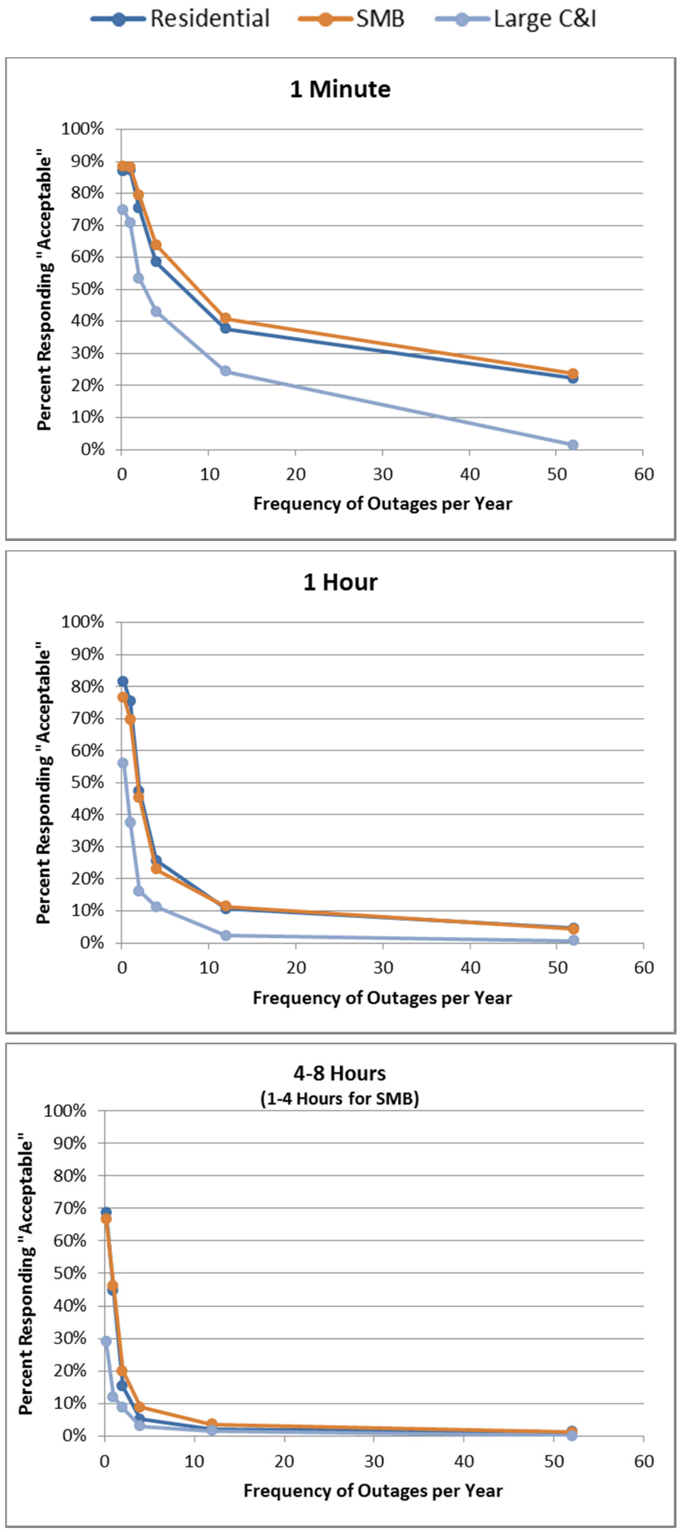
Figure 1-3:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Winter



1.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 1-4 shows the percent of customers rating each combination of outage frequency and duration as acceptable. As expected, a customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Large C&I customers have a higher standard than residential and SMB customers for what level of reliability is considered acceptable.

Figure 1-2:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Customer Class



2 Introduction

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study – research to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study. The primary objective of the VOS study was to estimate system-wide outage costs by customer class.

As VOS cannot be measured directly, it is estimated from outage cost surveys of utility customers. These cost estimates can be used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.[2] With the methodology employed in this study, the results can be directly applied to utility investments.

The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.

2.1 Study Methodology

The VOS analyses are based on data from in three separate surveys (one for each customer class) conducted between January and April, 2018. This survey methodology has been implemented by many electric utilities throughout the United States over the past 25 years. This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments and operating procedures. This methodology is described in detail in EPRI's Outage Cost Estimation Guidebook.[3] The results of 34 prior studies conducted using this methodology are part of a meta-analysis of nationwide outage costs that is summarized in a 2015 report by Lawrence Berkeley National Laboratory (LBNL).[4]

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers

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[2] For an early paper on value-based reliability planning, see: Munasinghe, M. (1981). "Optimal Electricity Supply, Reliability, Pricing and System Planning." Energy Economics, 3: 140-152.

[3] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[4] Sullivan, M. J., Schellenberg, J. & Blundell, M., 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Berkeley, CA: Lawrence Berkeley National Laboratory.

experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);
- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with various different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. These methods were selected for use for this THESL VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness-to-pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

Nexant used direct cost measurement for non-residential customers (SMB, and large C&I), as outage costs for these customers are more tangible and much less difficult to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$\begin{aligned} Direct\ Cost = {} & Value\ of\ Lost\ Production + Outage\ Related\ Costs \\ & - Outage\ Related\ Savings \end{aligned}$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is the business's net loss in the economic value of production after their ability to make up for lost production has been taken into account. It includes the entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);
- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on its electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described which are above and beyond the normal costs of production. If the customer is able to make up some percentage of its production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness-to-Pay Approach

Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating valuation, where customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following six metrics: cost per outage event, cost per average kW, cost per unserved kWh, duration cost per outage event, duration cost per average kW, and duration cost per unserved kWh. This section on the outage cost estimation methodology explains what each of these five key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These four sections provide the results for residential customers (Section 5), small/medium business (Section 6), large C&I (Section 7), and blended (Section 8). Results are presented for the metrics defined in Section 4. Each section concludes with results related to the level of reliability that each customer class considers acceptable.
- **Appendix A – Customer Damage Functions:** This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics.
- **Appendices B through D – Survey Instruments:** These appendices contain the survey instruments used for the study for each customer class.

3 Survey Methodology

Table 3-1 provides an overview of the survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, Nexant arranged to have a paper copy sent to the customer's mailing address. Customers for whom THESL had email addresses were sent an email with a direct link to that customer's unique online survey. SMB customers were recruited by telephone. They were encouraged to fill out the survey online, but were also offered the option of receiving a paper survey to complete and submit through the mail. If the customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large C&I customers were recruited by telephone and received an in-person interview. THESL key account representatives assisted with recruitment by contacting large C&I customers to inform them of the study and request their participation.

Although all survey instruments included variations of willingness-to-pay (WTP) and direct cost questions, the results in Sections 5 through 8 are based on the valuation methods listed in Table 3-1. Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during outages lasting 24 hours or less. Considering that most of the outage cost for residential customers is due to inconvenience or hassle, WTP is a better representation of their underlying costs. For SMB and large C&I customers, direct cost measurement is the preferred valuation method, as their outage costs are more tangible and much less difficult to estimate directly.

Table 3-1:
Survey Implementation Approach by Customer Class

Customer Class	Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	800	Letter/Email	Mail/Internet Survey	WTP	$10
SMB	800	Telephone	Mail/Internet Survey	Direct Cost	$50/$100
Large Business	100	Telephone	In-person Interview	Direct Cost	$150

3.1 Survey Instrument Design

The survey instrument asked customers to estimate interruption costs for six different hypothetical outage scenarios. The outage scenarios were described by five different factors: season, time of week, start time, end time, and outage duration. For each customer, the start time was the same for all scenarios to avoid confusion. Table 3-2 summarizes a set of outage scenarios for one particular customer. Each survey used either summer or winter as the season. Half of the surveys had summer as the season for scenarios A-E and winter as the season for scenario F. The other half had the seasons reversed. Each survey contained two scenarios with a 4-hour duration—one for summer and one for winter. The time of week was "Weekday" for all scenarios, as this survey was designed to facilitate modeling of seasonal variation instead of weekend/weekday variation. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

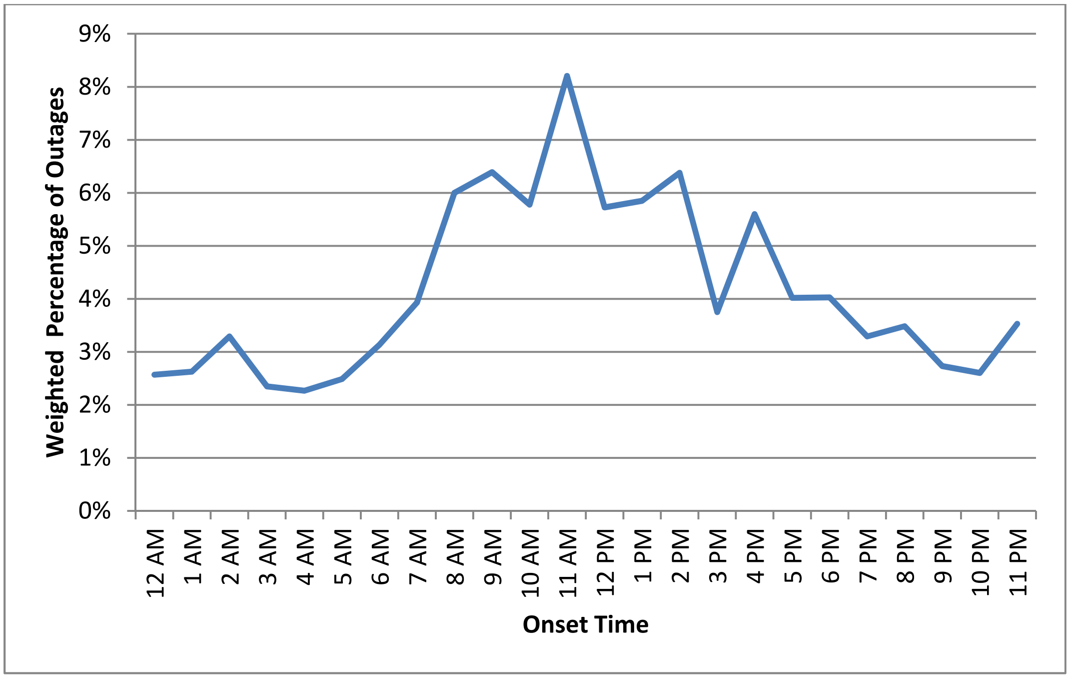
Table 3-2: Example Set of Outage Scenarios

Scenario	Season	Time of Week	Start Time	End Time	Duration
A	Summer	Weekday	11:00 AM	3:00 PM	4 hours
B	Summer	Weekday	11:00 AM	11:01 AM	1 minute
C	Summer	Weekday	11:00 AM	Noon	1 hour
D	Summer	Weekday	11:00 AM	7:00 PM	8 hours
E	Summer	Weekday	11:00 AM	11:00 AM (Next Day)	24 hours
F	Winter	Weekday	11:00 AM	3:00 PM	4 hours

The distribution of hypothetical onset times among survey respondents was determined by examining the historical distribution of outages for THESL from 2010-2017. Figure 3-1 shows the distribution of outage onset times for sustained outages during this time period.[5] The outages were weighted by the number of customers impacted by the outage. The most common weighted onset time was the 11:00 AM hour, which accounted for just over 8% of impacted customers. The survey instrument randomized the outage scenarios in proportion to the distribution of onset times in Figure 3-1. The outage cost estimates provided in Sections 5 through 8 are thus representative of the average outage cost across all time periods.

[5] The distribution excludes outages categorized by THESL as "momentary" or "planned." It also excludes outages occurring on major event days during the period, or for which the cause was loss of supply.

Figure 3-1:
Distribution of Sustained Outages by Onset Time
Weighted by Total Customers Interrupted (2010-2017)



3.2 Sample Design

The study aimed for the following number of completed surveys for each customer class:

- 800 residential customers;
- 800 SMB customers;
- 100 large C&I customers.

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a "customer" refers to a unique combination of "entity name" and "service address" in THESL's customer database. For residential customers, there was generally only one account ID associated with each unique combination. For non-residential customers, there could be multiple account IDs for an entity name-service address combination. When customers completed an outage cost survey, they provided cost estimates for the specific service address. Usage and customer contact information were aggregated across all of the accounts associated with each entity at each service address and then the customers were sampled.

Nexant stratified each customer class by the log of usage (a proxy for outage cost) by employing a two-step process to achieve an optimal sample stratification scheme. In the first step, Nexant identified the optimal stratum boundaries using the Dalenius-Hodges method. Next, it determined the optimal allocation among the Dalenius-Hodges strata using the Neyman allocation. This two-step approach is particularly useful for measuring skewed populations and maximizes survey precision for a given sample size and number of strata. This sampling approach is necessary as the distribution of usage per customer is highly skewed.

Tables 3-3, 3-4, and 3-5 summarize the sample designs for residential, SMB, and large C&I customers respectively. The residential and SMB customer classes each had four sample strata—labeled as 'usage categories' in the leftmost column of each table. The large C&I customer class was divided into three strata. For each of the customer classes, the sample stratification method led to the largest usage category having a larger percentage of customers in the sample than in the population. This allowed the sample to capture the higher and more variable outage costs for customers in those categories.

Table 3-3:
Sample Design Summary – Residential

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 0.25	62,103	9%	204	26%
0.25 to 0.57	194,060	30%	196	24%
0.57 to 1.1	252,994	39%	191	24%
1.1 and above	145,816	22%	208	26%
	654,973	**100%**	**800**	**100%**

Table 3-4:
Sample Design Summary – SMB

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 1.35	14,668	23%	204	26%
1.35 to 4.78	22,380	35%	196	25%
4.78 to 25.8	17,499	27%	191	24%
25.8 and above	9,146	14%	208	26%
	63,693	**100%**	**800**	**100%**

Table 3-5:
Sample Design Summary – Large Business

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
235 to 911	158	34%	27	27%
912 to 1934	189	41%	31	31%
1935 and above	113	25%	42	42%
	460	**100%**	**100**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was conducted online and via mail. It was distributed to the target respondents in two waves. In the first wave, respondents received a cover letter on THESL stationery explaining the purpose of the study and requesting their participation. This letter also contained a URL and unique respondent ID number so that respondents could complete the survey online. Approximately two weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask questions. Customers who completed the survey were sent a $10 incentive cheque in the mail.

3.3.2 Small & Medium Business Customers

SMB customers were first recruited by telephone to ensure that Nexant identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that an incentive was to be provided to thank the respondent for their time. The individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

One week after the survey link was emailed or the survey was faxed, respondents were given a reminder call. Customers who requested regular mail received their reminder calls after approximately two weeks. About ten days after the reminder calls were made to the email recipients, the email was re-sent to anyone who had not yet completed the survey. If the survey was still not completed within ten days, it was assumed that the customer would not complete the survey and they were not contacted again. An incentive of $50 was mailed to respondents who completed the survey form.

The recruitment effort for the initial sample of 3,200 customers did not yield the response rate normally seen with SMB customers for VOS studies. To boost the number of responses, Nexant obtained authorization from THESL to increase incentives from $50 to $100. It also drew an additional sample of 3,200 SMB customers to raise the total sample to 6,400. The response rate increased modestly from initial levels, but remained low compared to previous studies—as only 245 customers completed and submitted surveys out of a target of 800.

3.3.3 Large C&I Customers

For large C&I customers, an experienced telephone recruiter first located and recruited an appropriate representative at each of the sampled premises with the assistance of THESL. The target respondent was usually a plant manager or plant engineering manager – someone who was familiar with the cost structure of the enterprise. Once the target respondent was identified and agreed to participate, the scheduler set up an appointment with the field interviewer. Once the appointment was scheduled, Nexant emailed the customer a confirmation along with a written description of the study and an explanation of the information they would be asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the information. On the agreed upon date, Nexant's field interviewer visited the sampled site and conducted the in-person interview.

4 Outage Cost Estimation Methodology

4.1 Outage cost metrics

The results sections for each customer class (Sections 5 through 7) primarily focus on the following five outage cost metrics:

- Cost per Outage Event
- Cost per Average kW
- Cost per Unserved kWh
- Duration Cost per Outage Event
- Duration Cost per Average kW
- Duration Cost per Unserved kWh

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate, as it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost per customer resulting from each outage duration. It was derived by calculating a weighted average of the values that the respondent provided on the survey. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. The respondent was essentially providing the cost per outage event estimate. Before calculating the weighted average of these estimates, the top 0.5% of values normalized by usage was dropped from the analysis for residential and SMB. These outliers were dropped because respondents may erroneously provide unrealistically high estimates when taking an outage cost survey, as a result of human error or misunderstanding of the question. This step was skipped for large C&I customers as trained interviewers were walking customers through the questions. In addition, for residential customers, answers were considered outliers when the respondent selected the maximum $100 WTP response for all of the six scenarios (25 respondents). This set of responses suggested that the respondent was not carefully considering the outage scenario. After dropping outliers, cost per outage event was derived as an average of the customer responses, weighted by usage category for each segment.

Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\ Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred.

Duration cost per outage event is the cost per outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The other two duration cost metrics—duration cost per average kW and duration cost per unserved kWh—are calculated as described above, but with the adjusted event cost.

4.2 Special Considerations

Master metered customers: A number of large C&I customers were master metered, or bulk metered, meaning that one meter would serve the property owner, but that the building was occupied by multiple tenants. These tenants may or may not be sub-metered by a third party so that the property owner could bill them for electricity. THESL did not have contact information or consumption data for the tenants, as it did not directly meter the tenants. However, outage costs were incurred by the tenants. Interruption costs for master metered buildings were calculated by adding the outage costs for the property owner/manager with an estimate of the costs borne by the tenants. Tenant costs were estimated using either SMB or residential (depending on the type of tenant) cost per unserved kWh estimates and scaling them to the consumption level for the entire building.

Weekend/weekday differences: The outage scenarios in the survey instrument were designed to facilitate modeling seasonal differences in outage costs. Customers can only process a limited number of hypothetical scenarios before they get survey fatigue and introduce bias into the results. Therefore, all scenarios were for weekdays and the weekday/weekend differences for a recent interruption cost study for PG&E were used to adjust the estimates for this study for residential and SMB customers (but not for large C&I). The adjustments assume that interruptions are spread evenly across days of the week, such that weekend outage costs would be weighted by 2/7 and weekday costs by 5/7. The weekend adjustments for each time of day are shown below in Table 4.1.

Table 4-1:
Weekend Outage Cost Adjustments – Based on 2012 PG&E Study

Time of Day	Weekend Adjustment	
	Residential	SMB
Morning (7 AM to 11 AM)	-8%	-60%
Afternoon (12 PM to 5 PM)	-1%	-37%
Evening (6 PM to 9 PM)	20%	-61%
Night (10 PM to 6 AM)	4%	-58%

5 Residential Results

This section summarizes the results for residential customers.

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,061 total completed surveys, customer response was above the overall sample design target of 800. Overall, the survey had a 39.8% response rate that varied across usage categories. The second lowest usage category—with average kW of 0.25 to 0.57—had the highest response rate at 44 percent. The third usage category (0.57 to 1.1kW average) had nearly a 41 percent response rate. In the highest and lowest usage categories, the response rate was just over 37 percent. However, non-response bias among high and low usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis.

Table 5-1:
Customer Survey Response Summary – Residential

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 0.25	62,103	204	681	255	37.4%
0.25 to 0.57	194,060	196	653	287	44.0%
0.57 to 1.1	252,994	191	638	260	40.8%
1.1 and above	145,816	208	694	259	37.3%
All	**654,973**	**800**	**2,666**	**1,061**	**39.8%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such “protest responses” do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these protest responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that WTP was $0 because they thought it was unfair to pay more for electric service, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey.

The percentage of responses deemed invalid varied from 5.1% for a 24-hour outage to 6.0% for a 4-hour outage. The residential interruption cost estimates are based on the number of responses indicated in the “Valid Responses” category, which is fewer than what would normally be expected from a study with 1,061 responses. Note that the number of responses for the 4-hour outage duration was double those of other durations, as two of the six scenarios had 4-hour hypothetical outages.

Table 5-2:
Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
1 minute	1,061	55	5.2%	1006
1 hour	1,061	56	5.3%	1005
4 hours	2,122	127	6.0%	1,995
8 hours	1,061	56	5.3%	1005
24 hours	1,061	54	5.1%	1007

5.2 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates by region. For a 1-hour outage, residential customers experience a cost of $10.87 on average across the entire service territory. Cost per outage event increases to $23.35 at 8 hours and $34.53 for a 24-hour outage. Residents of York and North York generally report higher interruption costs, while residents of East York and Scarborough report lower costs. For a 1-hour interruption, Costs range from $8.55 to $13.39 for a 1-hour outage, $13.04 to $23.10 for a 4-hour outage, $17.55 to $27.12 for an 8-hour outage and $21.09 to $44.47 for a 24-hour outage. The percentage difference between regions increases with duration, suggesting that outages have a relatively higher incremental impact in North York as duration increases. However, it should be noted that East York and York both have small sample sizes. This means that the standard errors are larger and the confidence bands are wider. The small sample size could also partially account for the unusual result for York of a 1-hour outage valued slightly less than a 1-minute outage. There is a difference in the point estimates between the two durations but the confidence bands are overlapping.

Figure 5-1:
Cost per Outage Event Estimates by Region – Residential

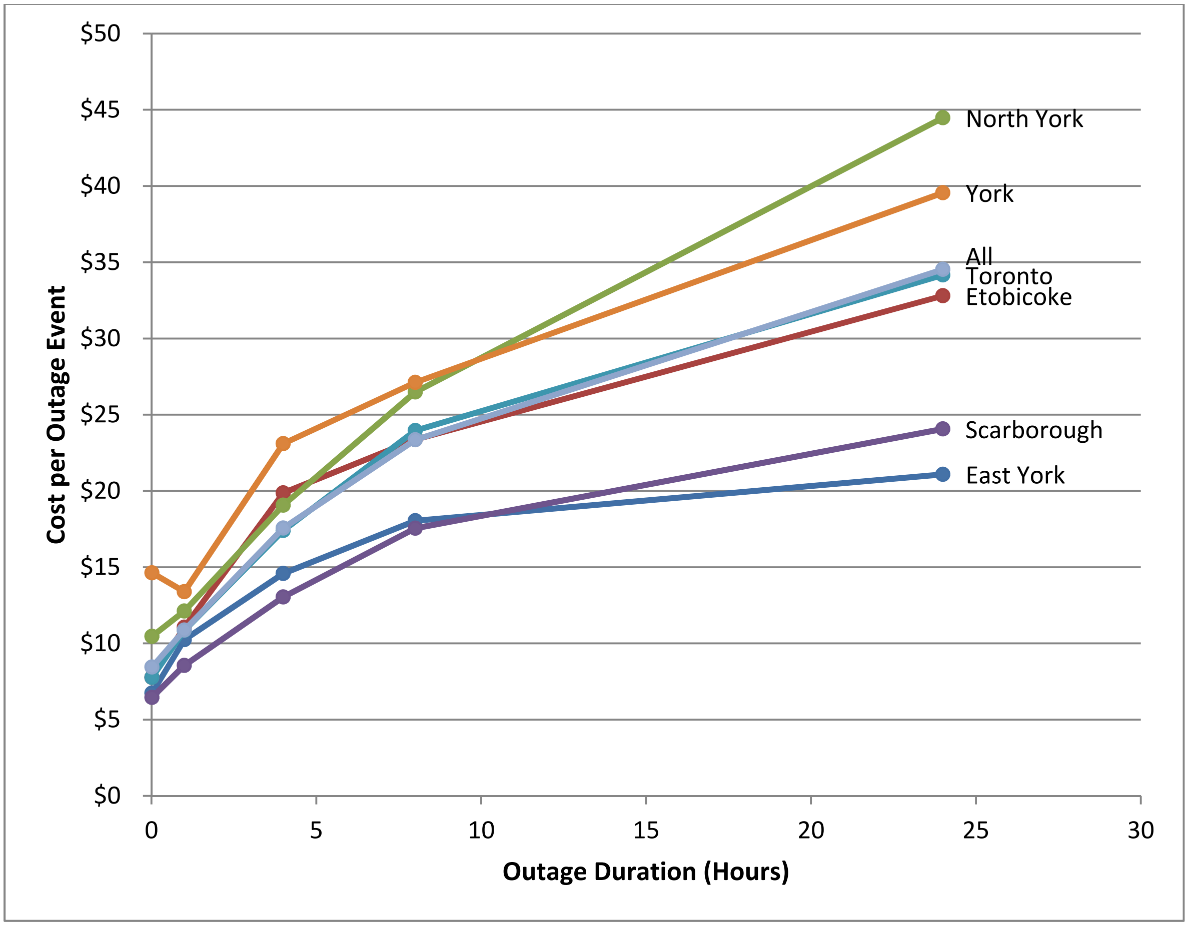


Table 5-4 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $13.21 per average kW. The cost per average kW estimates are roughly 20% higher than the cost per outage event estimates because average demand for residential respondents was around 0.8 kW. Scarborough and East York are again at the lower end of the cost range between regions. Costs range from$ 7.79 to $18.59 for a one-minute outage, $10.32 to $16.99 for a 1-hour outage, $15.77 to $29.33 for a 4-hour outage, $20.92 to $34.47 for an 8-hour outage and $26.86 to $50.31 for a 24-hour outage.

Table 5-5 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $13.21 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.8 at 1 hour. For a 1-minute outage, the system-wide cost estimate is over $616 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-3:
2018 Cost per Outage Event Estimates by Region – Residential

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$6.74	$2.77	$10.71
	1 hour	28	$10.24	$5.49	$14.99
	4 hours	55	$14.58	$10.25	$18.92
	8 hours	28	$18.04	$10.53	$25.54
	24 hours	28	$21.09	$11.75	$30.44
Etobicoke	1 minute	130	$7.76	$5.40	$10.12
	1 hour	132	$11.06	$7.89	$14.23
	4 hours	261	$19.87	$16.40	$23.35
	8 hours	130	$23.37	$16.17	$30.58
	24 hours	132	$32.80	$20.81	$44.79
North York	1 minute	224	$10.46	$8.12	$12.80
	1 hour	222	$12.12	$9.71	$14.53
	4 hours	447	$19.06	$16.41	$21.71
	8 hours	224	$26.49	$18.79	$34.18
	24 hours	223	$44.47	$28.35	$60.58
Scarborough	1 minute	150	$6.45	$4.67	$8.23
	1 hour	150	$8.55	$6.59	$10.52
	4 hours	290	$13.04	$11.27	$14.81
	8 hours	145	$17.55	$14.23	$20.88
	24 hours	146	$24.06	$19.89	$28.23
Toronto	1 minute	397	$7.76	$5.63	$9.89
	1 hour	397	$10.85	$9.02	$12.67
	4 hours	790	$17.40	$15.11	$19.68
	8 hours	402	$23.96	$19.35	$28.56
	24 hours	402	$34.16	$29.04	$39.28
York	1 minute	42	$14.62	$6.67	$22.57
	1 hour	42	$13.39	$7.88	$18.90
	4 hours	84	$23.10	$17.20	$29.00
	8 hours	42	$27.12	$18.97	$35.26
	24 hours	42	$39.56	$26.42	$52.69
All	**1 minute**	**972**	**$8.45**	**$7.31**	**$9.58**
	1 hour	**971**	**$10.87**	**$9.78**	**$11.96**
	4 hours	**1927**	**$17.56**	**$16.32**	**$18.81**
	8 hours	**971**	**$23.35**	**$20.53**	**$26.17**
	24 hours	**973**	**$34.53**	**$29.80**	**$39.27**

Table 5-4:
2018 Cost per Average kW Estimates by Region – Residential

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$8.39	$2.72	$14.06
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$18.72	$12.44	$25.00
	8 hours	28	$22.97	$12.66	$33.28
	24 hours	28	$26.86	$14.33	$39.40
Etobicoke	1 minute	130	$9.74	$6.72	$12.76
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$25.15	$20.84	$29.46
	8 hours	130	$29.52	$20.61	$38.43
	24 hours	132	$41.43	$26.55	$56.31
North York	1 minute	224	$10.86	$8.36	$13.36
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$19.73	$16.85	$22.62
	8 hours	224	$27.53	$19.60	$35.47
	24 hours	223	$46.12	$29.52	$62.72
Scarborough	1 minute	150	$7.79	$5.62	$9.95
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$15.77	$13.59	$17.94
	8 hours	145	$20.92	$16.97	$24.88
	24 hours	146	$28.76	$23.67	$33.84
Toronto	1 minute	397	$10.43	$7.47	$13.39
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$23.32	$20.16	$26.48
	8 hours	402	$32.30	$25.95	$38.64
	24 hours	402	$46.07	$38.90	$53.24
York	1 minute	42	$18.59	$8.09	$29.10
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$29.33	$20.93	$37.73
	8 hours	42	$34.47	$22.05	$46.90
	24 hours	42	$50.31	$30.56	$70.06
All	**1 minute**	**972**	**$10.27**	**$8.85**	**$11.69**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$21.36**	**$19.79**	**$22.92**
	8 hours	**971**	**$28.41**	**$24.98**	**$31.85**
	24 hours	**973**	**$42.04**	**$36.28**	**$47.79**

Table 5-5:
2018 Cost per Unserved kWh Estimates by Region – Residential

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$503.52	$163.28	$843.75
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$4.68	$3.11	$6.25
	8 hours	28	$2.87	$1.58	$4.16
	24 hours	28	$1.12	$0.60	$1.64
Etobicoke	1 minute	130	$584.25	$402.91	$765.60
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$6.29	$5.21	$7.36
	8 hours	130	$3.69	$2.58	$4.80
	24 hours	132	$1.73	$1.11	$2.35
North York	1 minute	224	$651.50	$501.36	$801.64
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$4.93	$4.21	$5.65
	8 hours	224	$3.44	$2.45	$4.43
	24 hours	223	$1.92	$1.23	$2.61
Scarborough	1 minute	150	$467.11	$337.12	$597.11
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$3.94	$3.40	$4.49
	8 hours	145	$2.62	$2.12	$3.11
	24 hours	146	$1.20	$0.99	$1.41
Toronto	1 minute	397	$625.61	$447.93	$803.30
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$5.83	$5.04	$6.62
	8 hours	402	$4.04	$3.24	$4.83
	24 hours	402	$1.92	$1.62	$2.22
York	1 minute	42	$1,115.60	$485.23	$1,745.97
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$7.33	$5.23	$9.43
	8 hours	42	$4.31	$2.76	$5.86
	24 hours	42	$2.10	$1.27	$2.92
All	**1 minute**	**972**	**$616.11**	**$531.06**	**$701.17**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$5.34**	**$4.95**	**$5.73**
	8 hours	**971**	**$3.55**	**$3.12**	**$3.98**
	24 hours	**973**	**$1.75**	**$1.51**	**$1.99**

Table 5-6 shows duration cost, duration cost per average kW, and duration cost per unserved kWh by region and overall. Duration cost is the event cost minus the event cost for a 1-minute outage. It represents the event cost beyond the momentary interruption. Thus, the duration cost for a one-minute outage is $0. The duration cost per unserved kWh is a similar calculation to Table 5-5, but it divides the duration cost—instead of event cost—by unserved kWh.

Table 5-6:
2018 Duration Cost Estimates by Region – Residential

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
East York	1 minute	29	$0.00	$0.00	$0.00
	1 hour	28	$3.50	$4.36	$4.45
	4 hours	55	$7.84	$9.76	$2.52
	8 hours	28	$11.30	$14.07	$1.80
	24 hours	28	$14.35	$17.87	$0.76
Etobicoke	1 minute	130	$0.00	$0.00	$0.00
	1 hour	132	$3.30	$4.14	$4.14
	4 hours	261	$12.11	$15.19	$3.83
	8 hours	130	$15.61	$19.59	$2.46
	24 hours	132	$25.04	$31.41	$1.32
North York	1 minute	224	$0.00	$0.00	$0.00
	1 hour	222	$1.66	$1.72	$1.72
	4 hours	447	$8.60	$8.93	$2.23
	8 hours	224	$16.03	$16.64	$2.08
	24 hours	223	$34.01	$35.31	$1.47
Scarborough	1 minute	150	$0.00	$0.00	$0.00
	1 hour	150	$2.11	$2.55	$2.54
	4 hours	290	$6.59	$7.96	$1.99
	8 hours	145	$11.11	$13.42	$1.66
	24 hours	146	$17.61	$21.27	$0.88
Toronto	1 minute	397	$0.00	$0.00	$0.00
	1 hour	397	$3.09	$4.15	$4.15
	4 hours	790	$9.64	$12.95	$3.23
	8 hours	402	$16.20	$21.76	$2.73
	24 hours	402	$26.40	$35.47	$1.48
York	1 minute	42	$0.00	$0.00	$0.00
	1 hour	42	$0.00	$0.00	$0.00
	4 hours	84	$8.48	$10.78	$2.69
	8 hours	42	$12.50	$15.89	$1.99
	24 hours	42	$24.94	$31.71	$1.32

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	972	$0.00	$0.00	$0.00
	1 hour	971	$2.42	$2.94	$2.94
	4 hours	1927	$9.11	$11.08	$2.77
	8 hours	971	$14.90	$18.11	$2.27
	24 hours	973	$26.09	$31.71	$1.32

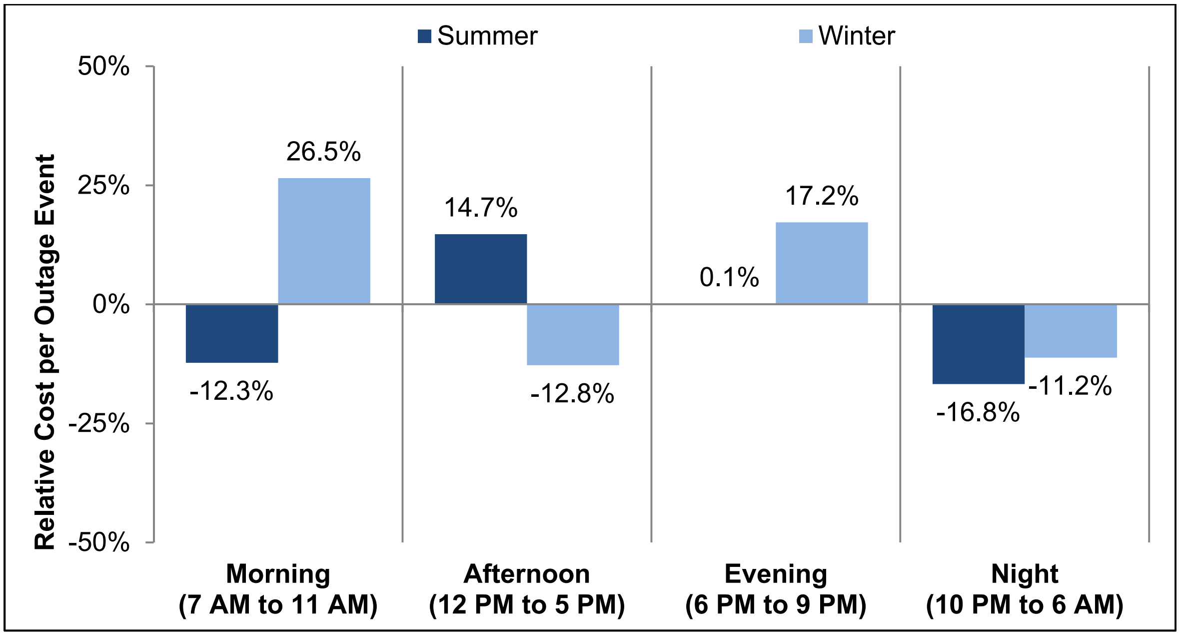
5.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 5-2 provides the relative cost per outage event estimates, which were derived from the residential customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the "base value"). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 16.8% lower than the base value on a summer night to 26.5% higher on a winter morning. Residential customers experience relatively high outage costs during winter mornings, winter evenings, and summer afternoons. These results could reflect the importance of home heating during winter mornings and evenings and home cooling during summer afternoons.

Figure 5-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Residential



5.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 5-3 and Table 5-7 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable. As expected, a residential customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Residential customers are willing to accept a relatively high frequency of short-duration outages.

Figure 5-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Residential

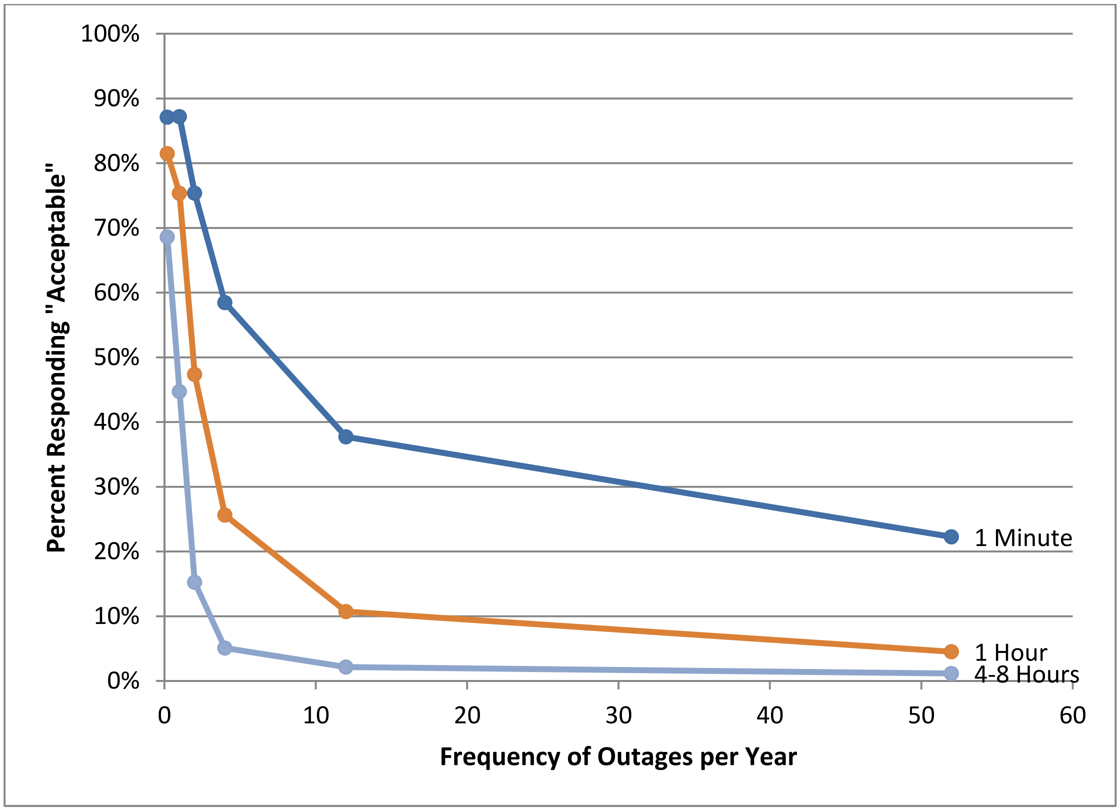


Table 5-7:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Residential

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

Table 5-8 shows two measures of satisfaction with service reliability. On a 5-point scale, with 1 as “Very Low” and 5 as “Very High,” residential customers report a 1.84 average rating for the number of power outages they experience. On a 5-point scale, with 1 as “Very Dissatisfied” and 5 as “Very Satisfied,” residential customers report a 4.05 average rating of their satisfaction with the level of service reliability they receive from THESL.

Table 5-8:
Satisfaction with Service Reliability – Residential

Question	Average Score
Do you feel the number of power outages your residence experiences is … (5-point scale, 1 for “Very Low” to 5 for “Very High”)	1.84
How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro? (5-point scale, 1 for “Very Dissatisfied" to 5 for “Very Satisfied”)	4.05

6 Small & Medium Business Results

This section summarizes the results for SMB customers.

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 245 total completed surveys, customer response was below the overall sample design target of 800. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. The original sample design had a sample draw of 3,200 customers for an expected response rate of 25 percent. Once the customers in the first sample draw had been contacted and it was clear that the response rate was below target, Nexant worked with THESL to boost responses by increasing incentives from $50 to $100 and adding 3,200 customers to the sample. Even with the increased incentives, the response rate remained low. It was similar across the four usage categories, ranging only from 3.5 percent to 4.2 percent.

Table 6-1:
Customer Survey Response Summary – SMB

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 1.35	14,668	204	1,638	62	3.7%
1.35 to 4.78	22,380	196	1,612	68	4.2%
4.78 to 25.8	17,499	191	1,620	56	3.5%
25.8 and above	9,146	208	1,530	59	3.8%
All	**63,693**	**800**	**6,400**	**245**	**3.8%**

6.2 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $857.84. SMB cost per outage event increases to $4,098 at 8 hours and $8,426 for a 24-hour outage. Results for SMB customers are not broken down by region, as the number of completed surveys was too small to obtain meaningful results for the pre-amalgamation municipalities.

Figure 6-1:
Cost per Outage Event Estimates – SMB

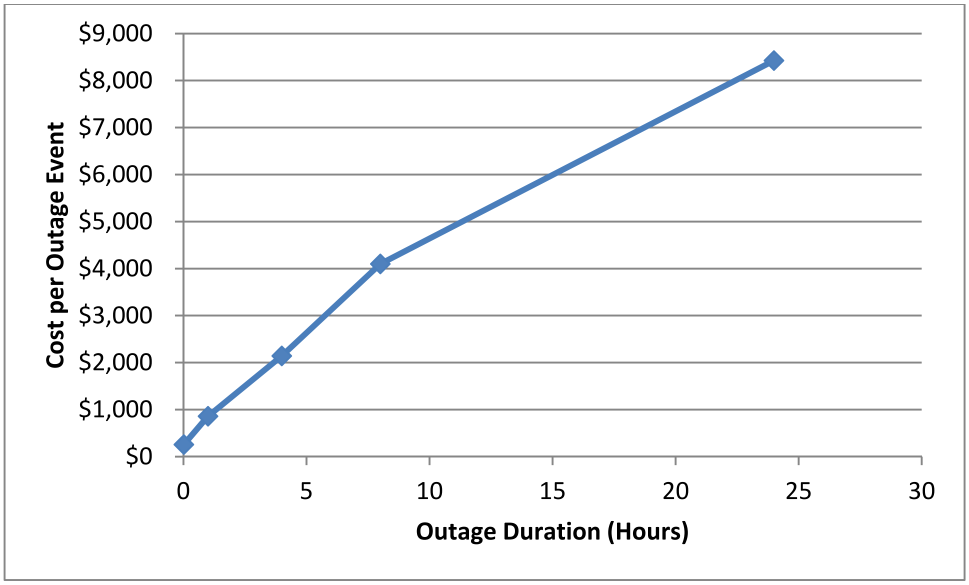


Table 6-2:
Cost per Outage Event Estimates– SMB

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$257.38	$161.82	$352.95
	1 hour	242	$857.84	$611.74	$1,103.94
	4 hours	477	$2,142.39	$1,779.13	$2,505.66
	8 hours	240	$4,098.01	$2,844.42	$5,351.59
	24 hours	239	$8,426.27	$5,892.16	$10,960.38

Table 6-3 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $40.68 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for SMB respondents was around 21 kW. Table 6-4 provides the SMB cost per unserved kWh estimates. For a 1-hour outage, SMB customers experience a cost of $40.68 per unserved kWh – same as the cost per average kW estimate. At 1-minute, the system-wide estimate is over $722, as the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. For a 24-hour outage, cost per unserved kWh is $16.64.

Table 6-3:
Cost per Average kW Estimates – SMB

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$12.04	$6.88	$17.20
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$98.29	$77.21	$119.37
	8 hours	240	$184.57	$131.62	$237.52
	24 hours	239	$399.42	$259.59	$539.25

Table 6-4:
Cost per Unserved kWh Estimates – SMB

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$722.43	$413.09	$1,031.76
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$24.57	$19.30	$29.84
	8 hours	240	$23.07	$16.45	$29.69
	24 hours	239	$16.64	$10.82	$22.47

Table 6-5 shows the duration cost, duration cost per average kW, and duration cost per unserved kWh for SMB. The duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the duration cost ranges from $600 for a 1-hour outage to $8,169 for a 24-hour outage. Duration cost per average kW ranges from $28.47 for a 1-hour outage to $382 for a 24-hour outage. Duration cost per unserved kWh ranges from $28.47 for a 1-hour outage to $16.13 for a 24-hour outage.

Table 6-5:
2018 Duration Cost Estimates – SMB

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	242	$0.00	$0.00	$0.00
	1 hour	242	$600.46	$28.47	$28.47
	4 hours	477	$1,885.01	$88.18	$21.62
	8 hours	240	$3,840.62	$179.67	$21.62
	24 hours	239	$8,168.89	$382.14	$16.13

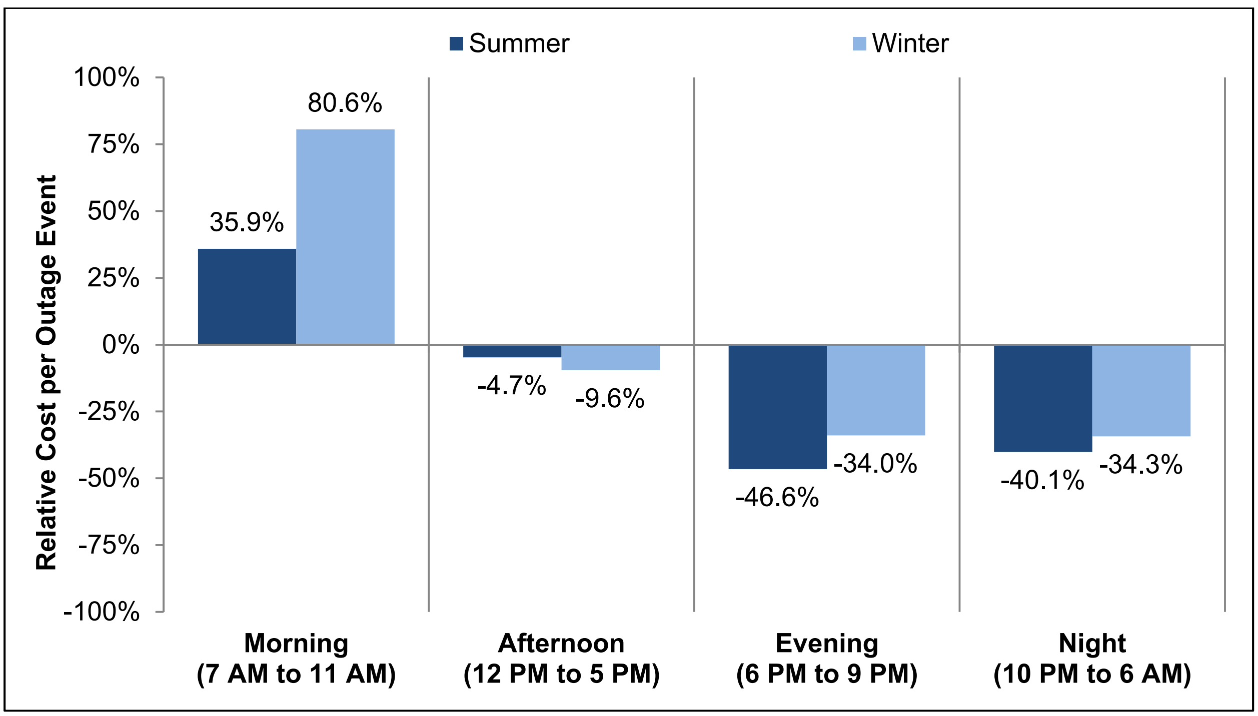
6.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 6-2 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each SMB outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are highly sensitive to onset time, varying from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. Outages with a morning onset time have the highest cost because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

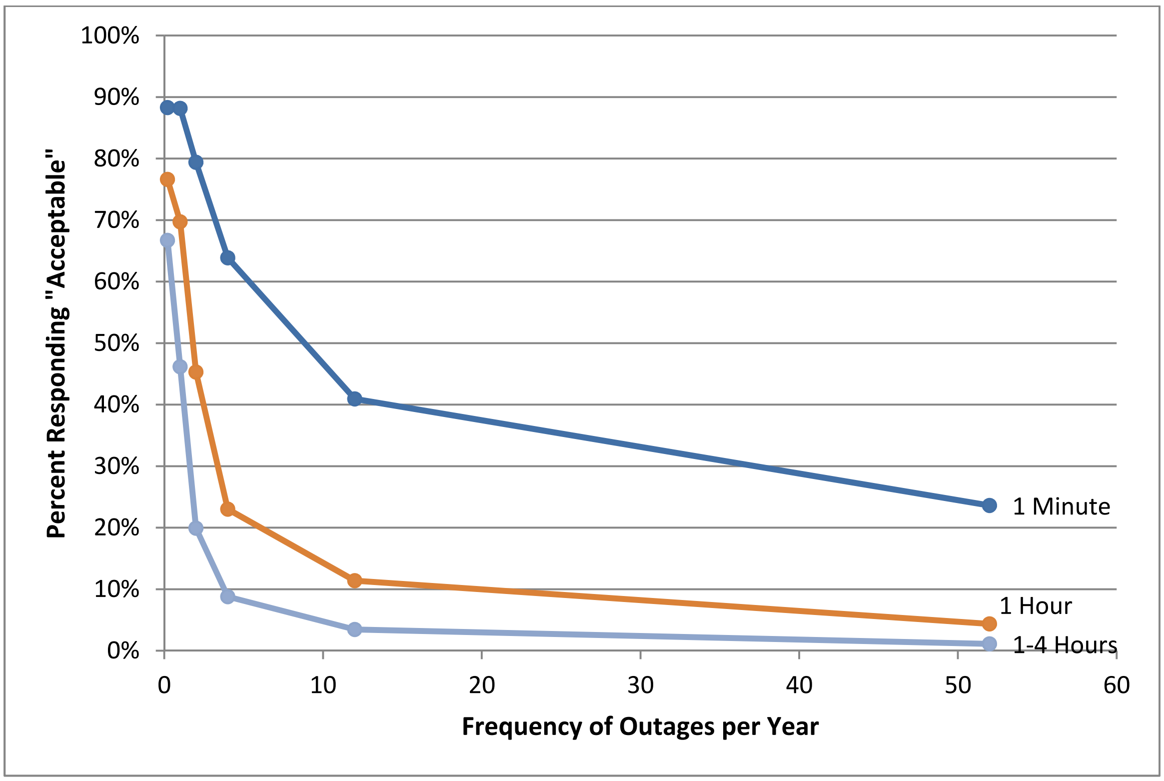
**Figure 6-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – SMB**



6.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 6-3 and Table 6-6 show the percent of SMB customers rating each combination of outage frequency and duration as acceptable. As expected, an SMB customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. SMB customers are willing to accept a relatively high frequency of short-duration outages. A majority of SMB customers reports that 4 momentary outages per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 46% of SMB customers, but four outages of this duration is acceptable to only 20 percent of customers.[6]

Figure 6-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB



[6] The longer-duration interruption for SMB was coded in the online survey as "1 to 4 hours" instead of "4 to 8 hours."

Table 6-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	1-4 Hours
All	Once every 5 years	88.3%	76.6%	66.7%
	1	88.2%	69.7%	46.2%
	2	79.4%	45.3%	19.9%
	4	63.9%	23.0%	8.8%
	12	40.9%	11.4%	3.5%
	52	23.6%	4.4%	1.1%

7 Large Business Results

This section summarizes the results for large business customers.

7.1 Response to Survey

Table 7-1 summarizes the survey response for large C&I customers. Nexant conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. In cases where the interviewee did not have it, Nexant attempted to follow up with the interview subject after the interview to obtain the missing data and calculate the outage cost estimate. This was successful for a number of large C&I customers. However, Nexant was not able to obtain the necessary data for 16 customers. The number of complete data points for large C&I was thus 84.

Table 7-1 shows a breakdown of the sample design by the three sample strata. Response rates were similar between strata, ranging from 28 percent to 33 percent.

Table 7-1:
Customer Survey Response Summary – Large C&I

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Complete Data Points	Response Rate
235 to 911	158	27	74	24	32%
912 to 1934	189	31	83	23	28%
1935 and above	113	42	113	37	33%
All	**63,693**	**100**	**270**	**84**	**31%**

7.2 Outage Cost Estimates

Figure 7-1 and Table 7-2 provide the large business cost per outage event estimates. For a 1-hour outage, large business customers experience a cost of $71,808. Large business cost per outage event increases to $379,381 at 8 hours and $992,647 for a 24-hour outage. The confidence intervals for these estimates are quite wide, as the large C&I customer class had a smaller sample size and much more variable outage cost estimates from customer to customer

Figure 7-1:
Outage Event Estimates – Large C&I

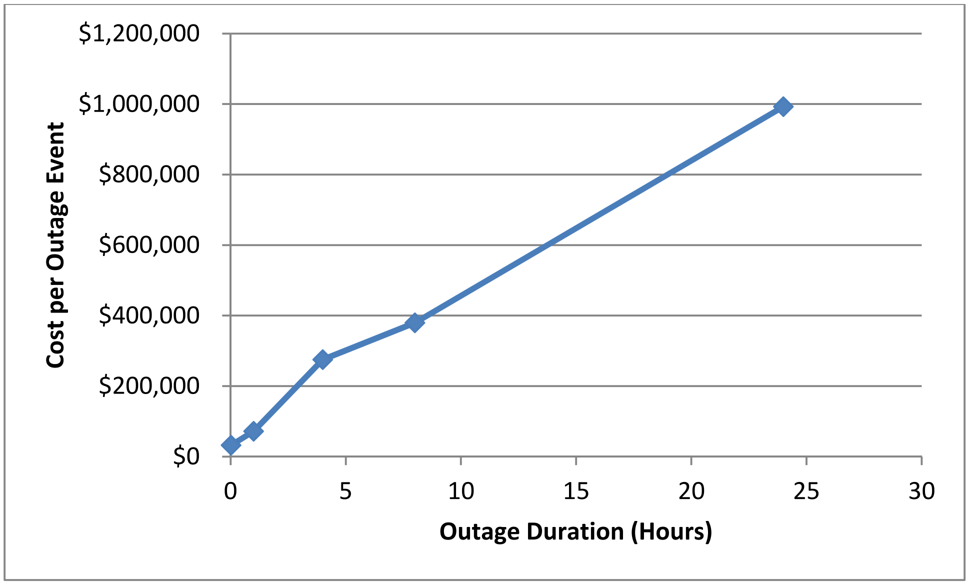


Table 7-2:
Cost per Outage Event Estimates – Large C&I

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$32,438	$5,886	$58,990
	1 hour	84	$71,808	$30,636	$112,979
	4 hours	168	$275,182	$77,202	$473,162
	8 hours	84	$379,381	$120,328	$638,433
	24 hours	84	$992,647	$214,801	$1,770,493

Table 7-3 summarizes large business cost per average kW. The cost per average kW values range from $15.25 for a 1-minute outage to $467 for a 24-hour outage. Table 7-4 provides the cost per unserved kWh estimates. For a 1-minute outage, large C&I customers experience a cost of $915 per unserved kWh. For the remaining durations, cost estimates range from $19.45 to $33.77 per unserved kWh. Table 7-5 shows the duration cost metrics. These costs range from $39,369 to $960,209 for duration cost, from $18.51 to $452 for duration cost per average kW, and from $18.51 to $28.54 for duration cost per unserved kWh.

Table 7-3:
Cost per Average kW Estimates – Large C&I

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$15.25	$2.69	$27.82
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$129.41	$34.25	$224.57
	8 hours	84	$178.41	$51.42	$305.40
	24 hours	84	$466.81	$87.68	$845.95

Table 7-4:
Cost per Unserved kWh Estimates– Large C&I

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$915.28	$161.23	$1,669.34
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$32.35	$8.56	$56.14
	8 hours	84	$22.30	$6.43	$38.18
	24 hours	84	$19.45	$3.65	$35.25

Table 7-5:
2018 Duration Cost Estimates by Region – Large C&I

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	84	$0.00	$0.00	$0.00
	1 hour	84	$39,369.44	$18.51	$18.51
	4 hours	168	$242,743.76	$114.16	$28.54
	8 hours	84	$346,942.45	$163.16	$20.39
	24 hours	84	$960,208.73	$451.56	$18.81

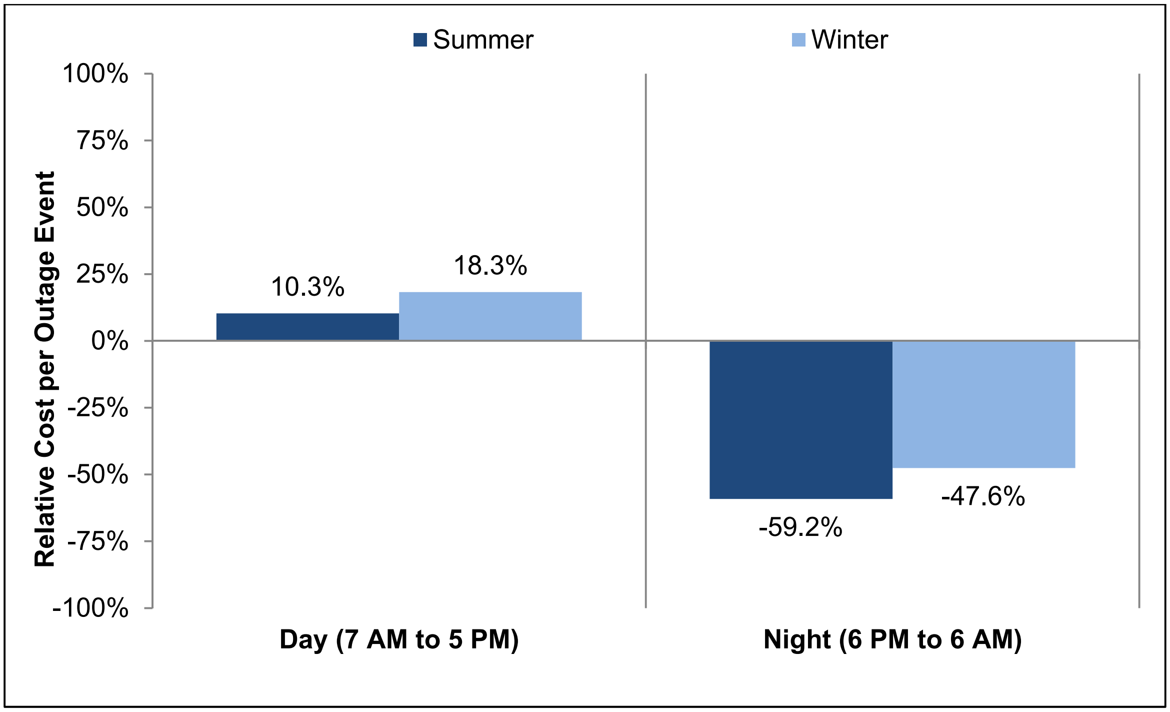
7.3 Impact of Outage Timing

For the large business analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 7-2 provides the relative cost per outage event estimates, which were derived from the large C&I customer damage functions described in Appendix A. Unlike the other 3 customer segments, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large business outage cost estimate in Section 7.2 (referred to as the “base value”). As shown in the figure, outage costs for large C&I customers are somewhat sensitive to onset time, varying moderately from 18.3% higher than the base value during daylight hours to 59.2% lower during the evening and night.

Figure 7-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Large C&I



7.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 7-3 and Table 7-6 show the percent of large business customers rating each combination of outage frequency and duration as acceptable. As expected, a large business customer’s level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. A single sustained outage more than 1 minute per year is considered unacceptable for a majority of large C&I customers. Four momentary outages is considered unacceptable by the majority.

Figure 7-3:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Large C&I

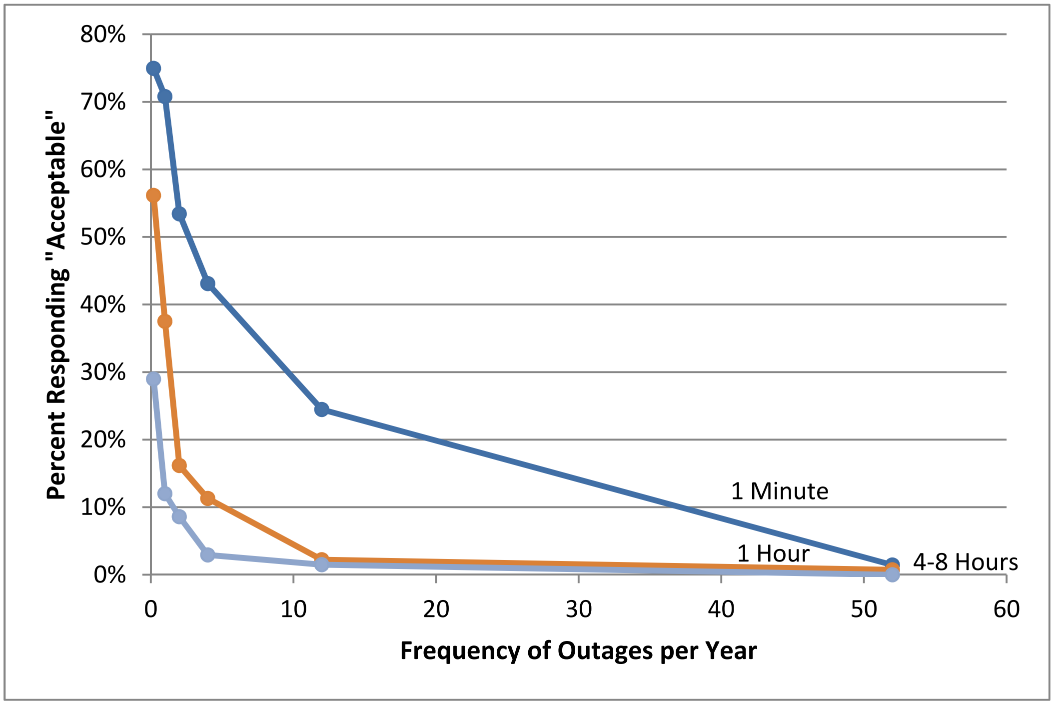


Table 7-6:
Percent of Customers Rating Each Combination of
Outage Frequency and Duration as Acceptable – Large C&I

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

8 Blended Results

This section summarizes the blended results for all customers. Sampling was conducted on a per-customer basis and the outage costs were collected and aggregated on a per-customer basis. The blended estimate calculations utilize the weighted average of per-customer costs as well as the weighted average of per-customer usage in order to scale the costs by kWh. Given that costs and usage are significantly higher for non-residential customers (particularly large C&I), their responses increase both average cost and usage. Thus the blended 'cost per average kW' and ‘cost per unserved kWh’ estimates account for non-residential customers having higher consumption.

Table 8-1 shows the blended cost per outage event estimate for each outage duration. The third column from the left—labeled ‘N’—shows the number of completed surveys from residential, SMB, and large C&I combined. The blended event costs range from $51.24 for a 1-minute outage to $1,413 for a 24-hour outage. Tables 8-2 ad 8-3 show the cost per average kW and cost per unserved kWh values, respectively. Blended cost per average kW values range from $12.80 for a 1-minute outage to $355 for a 24-hour outage. Blended cost per unserved kWh values range from $768 for a 1-minute outage to $14.80 for a 24-hour outage.

Table 8-1:
Cost per Outage Event Estimates – Blended Results

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$51.24	$31.95	$70.53
	1 hour	1297	$131.81	$95.71	$167.91
	4 hours	2572	$381.77	$247.75	$515.79
	8 hours	1295	$626.90	$418.09	$835.72
	24 hours	1296	$1,412.73	$844.74	$1,980.72

Table 8-2:
Cost per Average kW Estimates – Blended Results

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$12.80	$7.90	$17.70
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$94.50	$61.22	$127.78
	8 hours	1295	$153.83	$105.24	$202.43
	24 hours	1296	$355.23	$212.48	$497.98

Table 8-3:
Cost per Unserved kWh Estimates – Blended Results

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$768.06	$473.82	$1,062.30
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$23.63	$15.31	$31.95
	8 hours	1295	$19.23	$13.15	$25.30
	24 hours	1296	$14.80	$8.85	$20.75

Table 8-4 shows the blended duration cost, duration cost per average kW, and duration cost per unserved kWh. The blended duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the blended duration cost ranges from $80.57 for a 1-hour outage to $1,361 for a 24-hour outage. Duration cost per average kW ranges from $20.26 for a 24-hour outage to $340 for a 24-hour outage. Duration cost per unserved kWh ranges from $14.26 for a 24-hour outage to $20.45 for a 4-hour outage.

Table 8-4:
2018 Duration Cost Estimates – Blended

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	1298	$0.00	$0.00	$0.00
	1 hour	1297	$80.57	$20.26	$20.26
	4 hours	2572	$330.53	$82.57	$20.45
	8 hours	1295	$575.66	$143.81	$17.66
	24 hours	1296	$1,361.49	$340.13	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these “blended duration costs.” The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The “Outages Included” column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either “Momentary,” “Planned,” or “Sustained.” Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as “Loss of Supply Events” or could have occurred on “Major Event Days.” These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The “Event Cost” column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The “Duration Event Cost” column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The

“Duration” column shows the weighted average outage duration. The two “Hourly Cost” columns show each event cost per hour, or the “Event Cost” columns divided by the “Duration” column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

Table 8-5: Blended Duration Cost Based on Historical Outage Durations

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

9 Comparison to Other Studies

Nexant (formerly as Freeman, Sullivan & Co.) has conducted dozens of VOS studies for utilities and also works with Lawrence Berkeley National Laboratory to maintain the Interruption Cost Estimation (ICE) Calculator and its underlying database of survey-based VOS studies. The results from most studies for individual utilities are not public, but relatively recent studies from PG&E (conducted in 2012) and SCE (conducted in 2019) have public results that are useful for comparison. For other non-public studies contained in the ICE Calculator database, the utility is not identifiable, but the data can be aggregated and compared to current results. The ICE Calculator meta-database contains the results from 34 studies that use a similar, survey-based methodology.

Tables 9-1, 9-2, and 9-3 show the outage cost estimates from the PG&E and SCE studies for the residential, small/medium business and large C&I customer classes respectively. The tables show the results after adjusting for inflation (3% annually) and the exchange rate between the U.S. dollar and Canadian dollar (1.29 $CAD per 1 $US). The 2012 study separated results between the Bay Area and Non-Bay Area for PG&E and the tables show both sets of results along with the estimates for the service territory as a whole. Bay Area outage cost estimates were considerably higher than outage costs for the Non-Bay Area, SCE, and THESL. Residential outage costs for THESL were comparable to those of the Non-Bay Area and SCE. Small/medium business outage costs for THESL are considerably lower than both PG&E and SCE for the cost per outage event, cost per average kW, and cost per unserved kWh. Large C&I outage cost per event estimates are comparable to the Non-Bay Area and to SCE. However, the cost per average kW and cost per unserved kWh estimates are lower, indicating higher consumption for THESL customers.

The shape of THESL's outage cost distributions are similar to those of PG&E, SCE, and other studies, but they are generally lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL's customer interruption costs.

Table 9-1:
Comparison to PG&E and SCE Studies – Residential

Metric	Outage Duration	PG&E (2012) Bay Area	PG&E (2012) Non-Bay Area	PG&E (2012) All	SCE (2019)	Toronto Hydro
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$8.45
	5 minutes	$12.60	$10.72	$11.41	$5.75	-
	1 hour	$20.36	$16.50	$18.31	$8.50	$10.87
	4 hours	$30.18	$22.94	$25.91	$16.49	$17.56
	8 hours	$41.02	$30.48	$35.26	$25.02	$23.35
	24 hours	$58.27	$40.09	$48.78	$41.22	$34.53
Cost per Average kW	1 minute	-	-	-	-	$10.27
	5 minutes	$18.27	$12.92	$15.02	$7.89	-
	1 hour	$28.68	$18.75	$22.89	$11.86	$13.21
	4 hours	$42.50	$25.48	$32.39	$22.18	$21.36
	8 hours	$57.78	$33.87	$44.07	$34.04	$28.41
	24 hours	$83.24	$45.56	$61.75	$56.73	$42.04
Cost per Unserved kWh	1 minute	-	-	-	-	$616.11
	5 minutes	$209.99	$153.15	$190.23	$94.70	-
	1 hour	$29.10	$18.13	$22.89	$11.86	$13.21
	4 hours	$10.37	$6.16	$7.82	$5.55	$5.34
	8 hours	$7.02	$4.08	$5.30	$4.26	$3.55
	24 hours	$3.45	$1.89	$2.57	$2.37	$1.75

Table 9-2:
Comparison to PG&E and SCE Studies – Small/Medium Business

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$257
	5 minutes	$901	$245	$585	$670	-
	1 hour	$4,127	$1,500	$2,848	$3,881	$858
	4 hours	$10,178	$4,253	$7,354	$4,332	$2,142
	8 hours	$25,359	$6,831	$16,279	$5,825	$4,098
	24 hours	$52,034	$13,115	$32,870	$10,158	$8,426
Cost per Average kW	1 minute	-	-	-	-	$12
	5 minutes	$96	$30	$67	$86	-
	1 hour	$419	$188	$316	$541	$41
	4 hours	$1,087	$522	$832	$593	$98
	8 hours	$2,404	$859	$1,750	$857	$185
	24 hours	$5,364	$1,654	$3,702	$1,359	$399
Cost per Unserved kWh	1 minute	-	-	-	-	$722
	5 minutes	$1,099	$350	$760	$1,036	-
	1 hour	$403	$177	$301	$541	$41
	4 hours	$259	$122	$196	$148	$25
	8 hours	$296	$102	$213	$107	$23
	24 hours	$223	$69	$154	$57	$17

Table 9-3:
Comparison to PG&E and SCE Studies – Large Commercial & Industrial

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$32,438
	5 minutes	$1,173,397	$37,442	$700,348	$22,164	-
	1 hour	$1,326,775	$84,672	$692,616	$100,281	$71,808
	4 hours	$1,653,916	$175,206	$919,075	$189,506	$275,182
	8 hours	$1,664,031	$227,018	$950,684	$301,139	$379,381
	24 hours	$3,469,269	$947,921	$2,268,128	$558,639	$992,647
Cost per Average kW	1 minute	-	-	-	-	$15
	5 minutes	$843	$26	$492	$27	-
	1 hour	$962	$63	$504	$98	$34
	4 hours	$1,193	$132	$673	$235	$129
	8 hours	$1,188	$170	$693	$370	$178
	24 hours	$2,562	$683	$1,613	$780	$467
Cost per Unserved kWh	1 minute	-	-	-	-	$915
	5 minutes	$9,991	$310	$5,807	$323	-
	1 hour	$939	$61	$491	$98	$34
	4 hours	$293	$33	$166	$59	$32
	8 hours	$146	$21	$86	$46	$22
	24 hours	$106	$28	$67	$32	$19

Table 9-4 shows the blended results from the ICE Calculator meta-database. The ICE Calculator inputs were customized to correspond to the same number of residential, small C&I (<50,000 annual kWh) and medium/large C&I (> 50,000 annual kWh) as in the current study. While customizing the database to a Canadian province was not an option, it was possible to customize to New York State, which borders Ontario. The results from the ICE Calculator in 2016 U.S. dollars are in column 3 and column 4 contains the ICE Calculator results adjusted for inflation and exchange rate. The results from the current study are in the right-most column. The ICE Calculator results are significantly higher than the results from the current study. The difference is driven by the results from the non-residential customer classes.

Table 9-4:
Comparison to ICE Calculator Meta-Data – Blended

Metric	Outage Duration	ICE Calculator	ICE Calculator	Toronto Hydro
		$2016 US	$2018 CAD	$2018 CAD
Cost per Outage Event	1 hour	$385.80	$527.99	$131.81
	4 hours	$906.26	$1,240.27	$381.77
	8 hours	$1,927.47	$2,637.86	$626.90
	24 hours	$1,727.42	$2,364.08	$1,412.73
Cost per Average kW	1 hour	$100.76	$137.89	$33.14
	4 hours	$236.68	$323.91	$94.50
	8 hours	$503.38	$688.91	$153.83
	24 hours	$451.14	$617.41	$355.23
Cost per Unserved kWh	1 hour	$100.76	$137.89	$33.14
	4 hours	$59.17	$80.98	$23.63
	8 hours	$62.92	$86.11	$19.23
	24 hours	$18.80	$25.73	$14.80

Appendix A Customer Damage Functions

This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 7 related to how outage costs vary by time of day and season for each customer class.

To model outage costs, Nexant used a two-part model. The two-part model first estimates the latent probability that customers experience an outage cost with a Probit model. Then, it estimates the outage costs for customers who reported values greater than zero with a Generalized Linear Model (GLM). The models were estimated with corrections to account for the structure of the survey data (i.e., clustering by customer, population weights and stratification). This approach was first used to model health care expenditures, which, like outage costs, follow a highly skewed distribution. Nexant applied this model to a meta-analysis of outage costs in studies prepared for Lawrence Berkeley National Laboratory in 2009[1] and 2015.[2]

Nexant employed out-of-sample testing to select and validate the best econometric model for each customer segment. Because the model coefficients were derived from a system-wide survey, Nexant used out-of-sample testing to ensure that the estimates were robust to a variety of conditions. For each customer segment, Nexant experimented with different model specifications and estimated each model while withholding 25% of the data from the regression. To select the final model, Nexant compared the out-of-sample predicted outage costs from each model with the reported outage costs.

A.1 Residential Customers

To predict outage costs for residential customers, Nexant estimated an econometric model for residential customers from the survey data. The analysis included variables that capture customer size, duration of the outage, season, and time of day that the outage occurs.

Table A-1 shows the variables included in the residential customer regression model and the estimated coefficients for each part of the model. The natural log of average kW usage captures the influence of customer size on reported outage costs while duration and duration squared capture the impact of outage duration on reported outage costs. The square of the duration variable is meant to capture the non-linear relationship between outage costs and duration. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model. Most of the timing variables are

[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] Sullivan, M. J., Schellenberg, J. & Blundell, M. (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Berkeley, CA: Lawrence Berkeley National Laboratory.

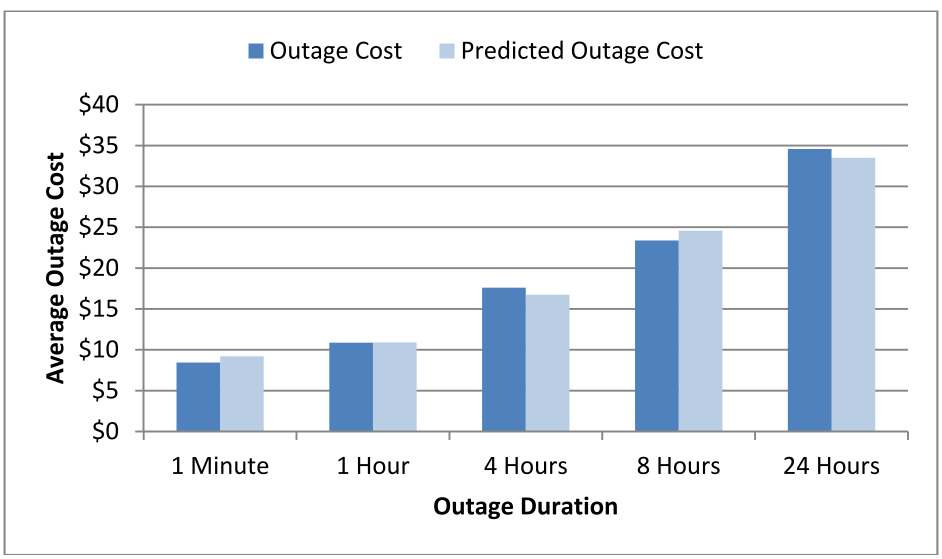
insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-1:
Coefficients of Customer Damage Function – Residential
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.062	0.187***
Duration	0.118***	0.085***
Duration Squared	-0.004***	-0.002***
Outage Timing		
Summer Night	-0.376**	-0.128
Winter Night	-0.369**	-0.065
Summer Morning	-0.202	-0.184
Winter Morning	-0.181	0.171
Summer Afternoon	-0.316**	0.136
Winter Afternoon	-0.279*	-0.156
Summer Evening	-0.273*	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Constant	0.227*	3.052***

Figure A-1 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is -3%; an 8-hour outage is 5%; a 4-hour outage, -5%; an hour, 0%; and 1 minute, 9%.

Figure A-1:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Residential



A.2 Small/Medium Business Customers

For SMB customers, variables that capture the size, outage timing, outage duration, and industry group were included for each premise. Multiple two-part models were tested. The criteria for selection of the final model included performance on out-of-sample tests, performance on in-sample tests and significance of coefficients on important variables.

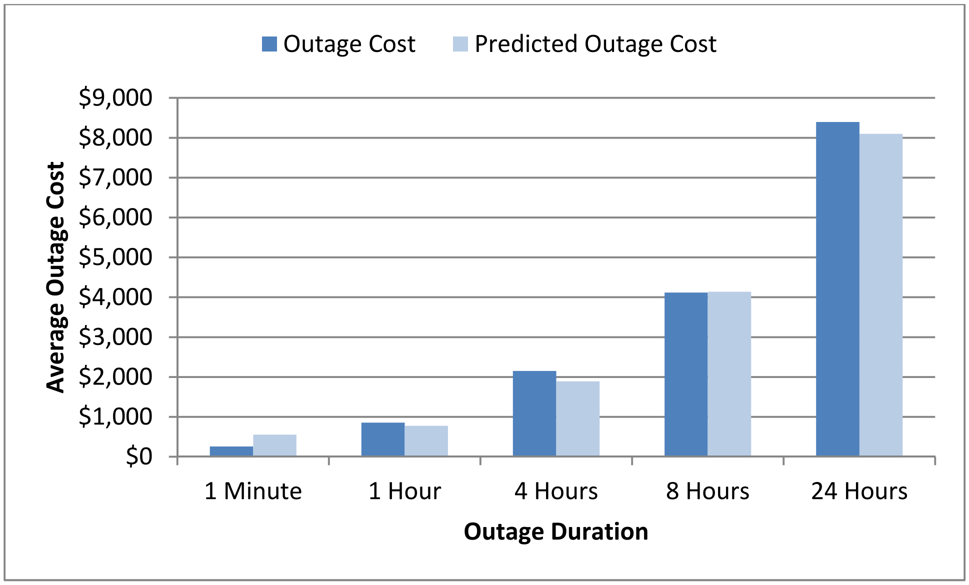
Table A-2 shows the variables included in the SMB customer regression model and the estimated coefficients for each part of the model. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model, indicating that outage timing determines both whether or not an SMB customer experiences outage costs. Specifically, customers with morning and afternoon outages (as opposed to evening and night outages) were more likely to report a cost above zero. The industry variables are insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-2:
Coefficients of Customer Damage Function – SMB
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.041	0.367***
Duration	0.223***	0.217***
Duration Squared	-0.006***	-0.006***
Outage Timing		
Summer Night	-0.067	-0.021
Winter Night	-0.163	0.288
Summer Morning	1.172***	0.522*
Winter Morning	0.967***	0.714*
Summer Afternoon	0.651**	0.244
Winter Afternoon	0.866***	0.177
Summer Evening	-0.025	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Industry		
Agriculture, Agricultural Processing & Food Processing	(omitted)	(omitted)
Assembly/Light Industry/High Tech	0.048	-0.425
Grocery Store/Restaurant	0.384	-0.226
Lodging (hotel, health care facility, dormitory, etc.)	-0.12	0.038
Office	-0.495	-0.35
Retail	0.041	0.317
Other/Unknown	-0.335	0.022
Constant	-0.672**	6.065***

Figure A-2 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts relatively well across all outage types. The percent error for a 24-hour outage is -4%; an 8-hour outage is 0%; a 4-hour outage, -12%; an hour, -9%; and 1 minute, 116%. Although the percentage difference for a 1-minute outage is quite high, the magnitude of the difference is not substantial considering that 1-minute outage costs are relatively low.

Figure A-2:
Comparison of Predicted and Reported Outage Cost by Outage Duration – SMB



A.3 Large Commercial & Industrial Customers

To predict outage costs for large business customers, Nexant estimated an econometric model from the survey data. Nexant included variables that capture the size, season, basic outage timing (night versus day), whether or not the premise is a multitenant facility, and variables to capture the duration of the outage. The Probit model also included basic industry group (commercial, industrial, public/institutional, other/unknown). As there were only 84 large business customers in the survey data, this model could not include as many variables as the SMB model.

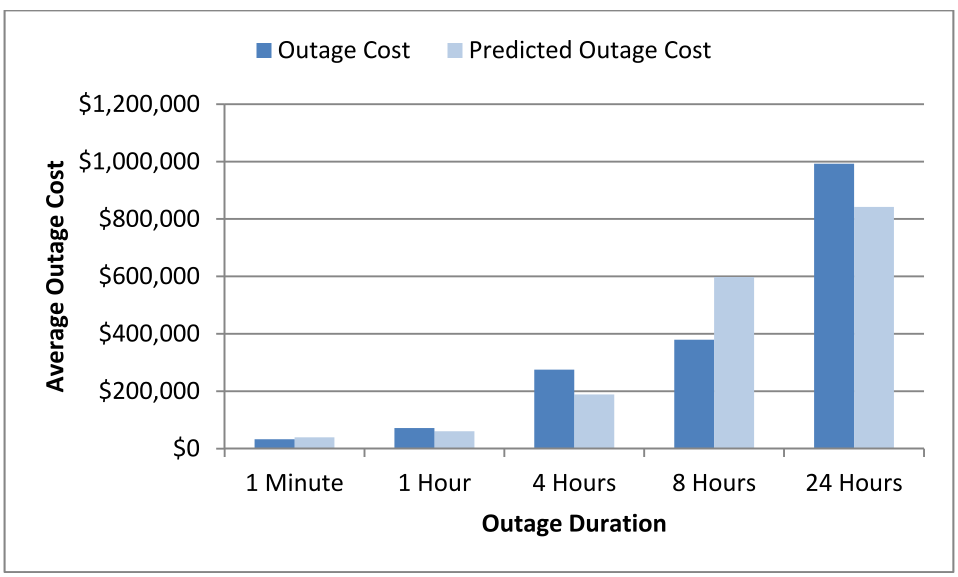
Table A-3 shows the variables included in the large business customer regression model and the estimated coefficients for each part of the model. The natural log of average kW is a significant predictor both of whether or not customers experience outage costs and of the magnitude of outage costs for customers who do report them. Both the duration and duration squared variables are significant at the 1% level in the GLM model. The 'Summer Night' and 'Winter Night' variables were significant at the 1% level for the GLM model, indicating outages that occur during the night are less impactful to large C&I customers. The multitenant variable, indicating whether the premise has multiple tenants, was not significant in the GLM model. This indicates that whether or not a premise has multiple tenants is an important predictor of the magnitude of outage costs for a given premise. The variable was not included in the Probit model due to data limitations.

Table A-3:
Coefficients of Customer Damage Function – Large Business
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	-0.635***	0.747***
Duration	0.025	0.432***
Duration Squared	-0.001	-0.013***
Master Metered	(omitted)	-0.822
Outage Timing		
Summer Night	0.282	-1.029***
Winter Night	0.711	-1.228***
Summer Day	-0.202	0.056
Winter Day (Base)	(omitted)	(omitted)
Industry		
Commercial (Base)		-
Industrial	(omitted)	-
Other/Unknown	0.235	-
Public/Institutional	1.207**	-
Constant	4.395**	5.860***

Figure A-3 provides a comparison of the model predicted and reported outage cost values by outage duration. The percent error for a 24-hour outage is -15%; an 8-hour outage is 58%; a 4-hour outage, -31%; an hour, -16%; and 1 minute, 21%.

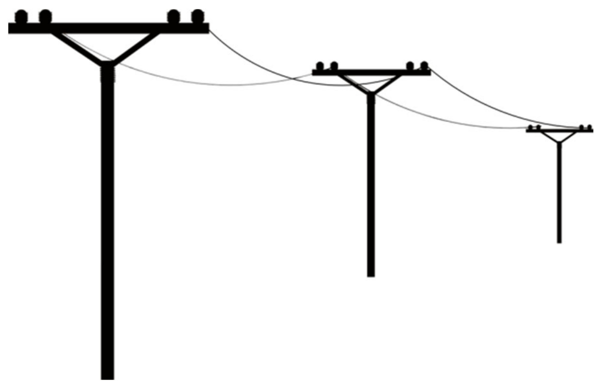
Figure A-3: Comparison of Predicted and Reported Outage Cost by Outage Duration – Large Business



Appendix B Residential Survey Instrument

Toronto Hydro 2017
Value of Service Study

Residential Customers



Thank you in advance for participating in this valuable study. Completing the survey will only take a few minutes of your time.

If you share a building with other owners or tenants, please answer the questions **only about your residence**.

All of your answers will be kept confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope to receive your $10 cheque as a token of our appreciation. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 11 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

This survey is also available online at: www.torontohydrosurveyres.ca
Your survey ID is «NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your residence. Power outages can be caused by many factors such as bad weather, traffic accidents and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your home? Write in the number of outages on the blanks. (If none, use "0".)

_______ A short duration (one minute or less)
_______ Longer than one minute and up to 1/2 hour
_______ Longer than 1/2 hour and up to 1 hour
_______ Longer than 1 hour and up to 4 hours
_______ Longer than 4 hours and up to 24 hours
_______ Over 24 hours

2. Do you feel that the number of power outages your residence experiences is…

☐ Very low
☐ Low
☐ Moderate
☐ High
☐ Very high

3. How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro?

☐ Very dissatisfied
☐ Somewhat dissatisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat satisfied
☐ Very satisfied
☐ Don't know

4. Do you or any of your household members work at home most of the time?

☐ No
☐ Yes -- What kind of business is it? ______________________________________

4a. **If you answered "Yes" in question 4**, how are you compensated for the work you perform at home?

☐ Self-employed
☐ Salary from employer
☐ Hourly wage from employer

5. Do you or does anyone in your household have any health conditions for whom a power outage could be a problem?

☐ No
☐ Yes – Please explain: ____

5a. **If you answered "Yes" in question 5**, have you registered with Toronto Hydro for the Life Support Notification Program at torontohydro.com/lifesupport?

☐ No
☐ Yes

Note – this notification program is only for planned power outages. We strongly encourage customers to always have back-up and to plan for power outages caused by unpredictable events.

Next, we'll ask you about 6 different types of electrical power outages. For each type of outage, we would first like to know how you and your household would adjust to the outage. Second, we would like you to estimate the extra expenses that your household would experience as a result of this type of outage as well as the estimated cost of inconvenience or hassle. Some of the expenses and inconveniences that people might experience include using candles if it's dark, going out to eat if you're unable to cook at home, food spoiling, etc.

Because every person may feel differently about the amount of extra expenses and the inconvenience or hassle, there are no right or wrong answers to these questions. We simply want your honest opinion.

IMPORTANT

As you answer the questions, please remember these two definitions:

Inconvenience or hassle costs
When a power outage occurs, a household may experience inconvenience or hassle costs while adjusting to the outage. These may include having to use candles if it's dark, having to dine out, not being able to watch television or not being able to use the internet.

Note: If you have solar photovoltaic (PV) panels installed, your household will still experience the power outage and your PV system will not feed electricity into the grid.

Extra expenses
These may include food spoilage, dining out, or lost wages for lost work time due to outages. In adding up your extra expenses, please do **not** include expenses that your household would have incurred whether or not the power outage happened. For example, if you decided to dine out during the outage **instead of** another night, the cost of the dinner should **not** be considered as an extra expense because it's simply shifted from another night. However, if you had to dine out during the outage **in addition to** another night, the cost of the dinner should be considered an extra expense.

Case A:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored. Note that **all** of the remaining cases occur at **<<ONSET>>**.

SUMMARY:

Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 4 hours **End time:** <<END1>>

A1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

A2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

A3. Of the above amount, how much of it would be **just for the extra expenses**?

$ [ ] extra expenses **only**

A4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

A4a. **If you selected $0 in question A4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case B:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 minute** your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	1 minute	**End time:**	<<END2>>

B1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

B2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

B3. Of the above amount, how much of it would be **just for the extra expenses**?

$ [ ] extra expenses **only**

B4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

B4a. **If you selected $0 in question B4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case C:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 hour** your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	1 hour	**End time:**	<<END3>>

C1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

C2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ [ ] extra expenses **and** inconvenience costs

C3. Of the above amount, how much of it would be **just for the extra expenses**?

$ [ ] extra expenses **only**

C4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_________

C4a. **If you selected $0 in question C4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case D:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **8 hours** your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	8 hours	**End time:**	<<END4>>

D1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

D2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **and** inconvenience costs

D3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

D4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

D4a. **If you selected $0 in question D4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case E:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **24 hours** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 24 hours **End time:** <<END5>>

E1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

E2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **and** inconvenience costs

E3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

E4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_________

E4a. **If you selected $0 in question E4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case F:
On a **<<SEASON2>>** weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored.

SUMMARY:

Conditions:	**<<SEASON2>>** weekday	**Start time:**	<<ONSET>>
Duration:	4 hours	**End time:**	<<END6>>

F1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ________________________________

F2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ ________ extra expenses **and** inconvenience costs

F3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

F4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $__________

F4a. **If you selected $0 in question F4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

If each of the following occurred, would you think you were getting an <u>acceptable or unacceptable level of service reliability</u>?

6. An outage lasting **1 minute or less**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

7. An outage lasting **about an hour**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

8. An outage lasting between **4 hours and 8 hours**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

To better understand how electrical power outages affect your household, we would like to gather some information on your household characteristics. Please answer the following questions to the best of your ability. If you live in an apartment building or duplex, answer only for the part of the building you actually live in.

Some background information about the people living in your household will also help us understand how electrical power outages would affect your household. Again, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9. What type of residence is this? Please check one.

- ☐ Single family house (house on separate lot)
- ☐ Row or townhouse (walls adjacent to another house)
- ☐ A unit in a multi-family structure, 2-4 attached units (example: duplex, triplex, fourplex, or single family house converted to flats)
- ☐ A unit in a large multiple family structure, 5 or more attached units (example: apartment house, high rise condominium, garden apartments)
- ☐ Mobile home, house trailer
- ☐ Other (please describe) ________________________________

10. Do you own or rent your residence?

☐ Own ☐ Rent/Lease ☐ Other (specify) ________________________

11. How many years have you lived at this address? (If less than 1 year, write "0".)

_______Years

12. Which of the following best describes your household? Please choose one.

- ☐ Individual living alone
- ☐ Single head of household with children at home
- ☐ Couple with children at home
- ☐ Couple without children at home
- ☐ Unrelated individuals sharing a residence
- ☐ Other (please describe) ________________________________

13. In approximately what year was this residence built? ________

14. What is the size of your residence? ________square feet

15. How many people, **including yourself**, live in your home? ________

16. Please indicate the number of individuals in your household who are in each of these age groups.

_______ Under 6 _______ 25 to 34 _______ 55 to 59
_______ 6 to 18 _______ 35 to 44 _______ 60 to 64
_______ 19 to 24 _______ 45 to 54 _______ 65 or over

17. Which one of the following age groups best describes your age?

☐ Under 25 ☐ 25 to 44 ☐ 45 to 64 ☐ 65 or over

18. Which of the following categories best describes your total household income during 2017 before taxes and other deductions? Please include all income to the household including social security, interest, welfare payments, child support, etc.

☐ 0 - $9,999 ☐ $20,000 - $29,999 ☐ $50,000 - $74,999
☐ $10,000 - $14,999 ☐ $30,000 - $39,999 ☐ $75,000 - $99,999
☐ $15,000 - $19,999 ☐ $40,000 - $49,999 ☐ $100,000 or more

19. Do you own an electric vehicle?

☐ Yes ☐ No

20. Is electricity your primary source of heating in winter?

☐ Yes ☐ No ☐ I don't know

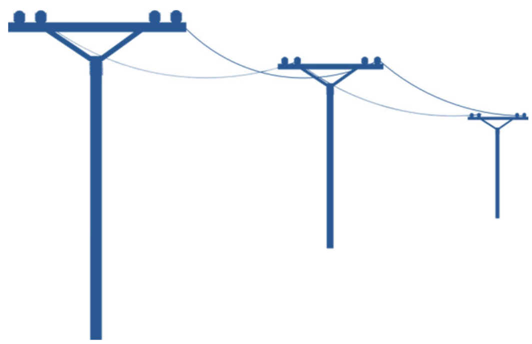
Please share any additional comments:

Please be sure to return your completed survey.
Thank you!

Appendix C Small/Medium Business Survey Instrument

Toronto Hydro
2017 Value of Service Study

Business Customers



Dear Customer,

Thank you for agreeing to participate in this important study. We're asking you to fill out this survey thinking <u>only</u> about the facilities that your company occupies **at this location:**

«SERVICE_ADDRESS», «SERVICE_CITY»

If your company shares a building with other businesses or you're the property manager at the above address(es), please answer the questions **only for the space <u>your company</u> occupies at this location and the activities <u>your company</u> undertakes**.

All your answers will be kept confidential. Your name and your company's name and address will be kept anonymous and will not be associated with the information you provide.

Please complete the survey to receive your $50 cheque. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 9 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

«NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your facility. Power outages can be caused by many factors, such as bad weather, traffic accidents, and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your business location? Write in the number of outages on the blanks. (Use "0" if none.)

   A) Short duration or momentary (one minute or less) ________

   B) Longer than one minute and up to 1/2 hour ________

   C) Longer than 1/2 hour and up to 1 hour ________

   D) Longer than 1 hour and up to 4 hours ________

   E) Longer than 4 hours and up to 24 hours ________

   F) Over 24 hours ________

2. In general, how disruptive have these outages been for your company? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not at all disruptive						Very disruptive

3. Has your company ever sent employees home during a power outage?

   ❑1 No
   ❑2 Yes

4. In general, how long can an outage last at your facility before the costs become significant? Please estimate that time length in minutes and/or hours:

   ___________ **Hours and** ___________ **Minutes**

«NEXID»

5. How much advance warning of a power outage does your company need to significantly reduce the problems caused by a power outage?

- ❑1 Advance notice would not reduce problem(s)
- ❑2 At least 1 hour
- ❑3 At least 4 hours
- ❑4 At least 8 hours
- ❑5 At least 24 hours

How satisfied are you with… (Please check one number.)	**Extremely Dissatisfied**						**Extremely Satisfied**
6. The reliability of the electrical service your company has experienced in the **last 12 months**?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
7. The length of time it usually takes to restore service after an outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
8. The responsiveness of Toronto Hydro when you have a power outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7

The next section describes **six** different types of power outages. We'd like to know the **costs to your business** of adjusting to each of these power outages.

For many businesses, the costs of a power outage depend upon the particular situation, and **may vary** from day to day depending upon business conditions. So for each outage type you'll be given the opportunity to report the **range of outage costs** that your business might face (from low to high), as well as to estimate **the cost that you would most likely have** under typical circumstances.

It's important to try to answer all of the questions. If a question is difficult for you to answer, **please give us an estimate** and feel free to **write down any comments about your answer**.

Case 1:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored. Note that **all** of the remaining cases occur at **«ONSET».**

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END1»

9. How disruptive would this power outage be to your business?
(Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not disruptive at all						Very disruptive

10. Would your operations or services typically stop or slow down as a result of this power outage? (If yes, please state the number of hours.)

❑1 No--------------------> SKIP TO CASE 2 ON PAGE 6

❑2 Yes-------------------->__________ Number of hours that operations or services would stop or slow down (include time **during and after** the power outage)

11. What's the approximate dollar value of the operations or services that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? (If you're not sure please make your best guess.)

$__________ value of lost work or services

12. What percent of the operations or services typically would be made up after the power outage? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

13. Would there be **labour costs** associated with this power outage such as salaries and wages for staff who would be unable to work or overtime pay to make up for operations or services? (If yes, please state the cost for lost labour as well as the cost for overtime labour to make up for lost work.)

❑1 No
❑2 Yes -->$_______labour costs of staff unable to work during the power outage

$_______labour costs in overtime/extra shifts to make up for lost work

14. Would there be any **damage costs** associated with this power outage such as damage to equipment, materials, etc.? (If yes, please state how much the damage cost for equipment would be and how much the damage cost to materials would be.)

   - ❑1 No
   - ❑2 Yes --->$_______damage to equipment

     $_______damage to materials

15. Would there be **additional tangible costs** associated with this power outage (such as extra restart costs, and costs to run and/or rent backup equipment)? (If yes, please state the additional costs.)

   - ❑1 No
   - ❑2 Yes --->$_______additional tangible costs

16. If you had to put a dollar value on **intangible costs** due to this power outage (such as inconvenience or dissatisfied customers), what would these costs be? (If yes, please state the intangible cost.)

   - ❑1 No, there would be $0 intangible costs
   - ❑2 Yes, there would be $_______ intangible costs

17. In addition to the costs discussed above, some organizations may avoid business expenses because of electrical outages. Some examples include a lower electrical bill, lower material outlays, and lower personnel costs. Would you experience any savings associated with this power outage? (If yes, please state the savings.)

   - ❑1 No
   - ❑2 Yes --->$_______savings

18. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 2:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 minute** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 minute	**End time:**	«END2»

19. Considering **all** of the costs you might experience as a result of this **1-minute «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 3:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 hour** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END3»

20. Considering **all** of the costs you might experience as a result of this **1-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 4:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **8 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	8 hours	**End time:**	«END4»

21. Considering **all** of the costs you might experience as a result of this **<u>8-hour «SEASON1» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 5:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **24 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5»

22. Considering **all** of the costs you might experience as a result of this **<u>24-hour «SEASON1» weekday outage beginning at «END5»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$__________**	**$__________**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 6:
On a **<u>«SEASON2»</u>** weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	**<u>«SEASON2»</u>** weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END6»

23. Considering **all** of the costs you might experience as a result of this **<u>4-hour «SEASON2» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	$__________	$__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

WHAT LEVEL OF RELIABILITY IS ACCEPTABLE?

Toronto Hydro works hard to prevent power outages, but eliminating all outages could be very costly, if not impossible.

The following questions help us understand what you consider acceptable service from Toronto Hydro.

24. If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro? Please check a box for each statement whether you find the outage period acceptable or unacceptable.

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your company will help us understand how power outages affect your type of business.

Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

25. Which of the following categories best describes your business? (Please check one.)

- ❑ 1 Agriculture/Agricultural Processing
- ❑ 2 Assembly/Light Industry
- ❑ 3 Chemicals/Paper/Refining
- ❑ 4 Food Processing
- ❑ 5 Grocery Store/Restaurant
- ❑ 6 Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ 7 High Tech
- ❑ 8 Lumber/Mining/Plastics
- ❑ 9 Office
- ❑ 10 Oil/Gas Extraction
- ❑ 11 Retail
- ❑ 12 Stone/Glass/Clay/Cement
- ❑ 13 Transportation
- ❑ 14 Utility
- ❑ 15 Other (please specify):______________________________

26. What's the approximate square footage of the facility referred to at the beginning of the survey? (Note: "facility" refers to the building(s) that your business occupies at that location.)

__________ Square feet

27. How many **full-time** (30+ hours per week) employees are employed by your company at that location?

__________ Full-time employees

28. List the number of people employed by your business at this company location in each of the following categories:

___________ # of part-time year-round employees

___________ # of full-time seasonal employees

___________ # of part-time seasonal employees

29. What's the approximate value of your business's total annual revenue?

$___________ per year

30. What's the approximate value of your business's total annual expenses (including labour, rent, materials, and other overhead expenses)?

$___________ per year

31. Approximately what percentage of your business's annual operating budget is spent on electricity?

___________ %

32. Does your company have any electrical equipment that's sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? (If yes, please state the type of equipment.)

- ❑1 No
- ❑2 Yes ---->What equipment? ___________________________________

33. Does your business own or rent/lease any of the following devices to protect this equipment? (Please check all that apply.)

- ❑1 Back-up generator(s)
- ❑2 Uninterruptible power supply
- ❑3 Line conditioning device(s)
- ❑4 Surge suppressor(s)
- ❑5 Isolation transformer(s)

34. Does your business have any electrical equipment that would continue to operate during a power outage? (If yes, please state the type of equipment.)

- ❑1 No
- ❑2 Yes ----->What equipment? ___________________________________

Please share any additional comments:

THANK YOU FOR YOUR HELP!

Please provide your contact information so that we may mail you the incentive cheque.

The incentive cheque can be made out to any individual or charitable organization as designated by you. It should arrive in 2-4 weeks.

If you choose not to accept any incentive, please write “decline.”

Name on cheque: ____________________

Address (Line 1): ____________________

Address (Line 2): ____________________

City: ____________________

Province: ____________________

Postal Code: ____________________

Appendix D Large C&I Survey Instrument

Associated Delivery Numbers (Acct #)

NEXID #: «NEXID»

Date of Interview: ___________________

Interviewer Name: ___________________

Interview Start Time: _________________

Interview End Time: _________________

Name: **Title:**

Name: **Title:**

Name: **Title:**

I'd like to talk to you about the costs of power outages for:
(Describe the part of the site served by the selected deliveries.)

Company Name:

Service Address:

If delivery serves only part of the site, describe location served:

OUTAGE SCENARIOS

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

What are the operating hours of this facility?

Use military time. If open 24 hours, use 00:00 to 00:00.

	Weekday Open	Weekday Close		Saturday Open	Saturday Close		Sunday Open	Sunday Close
Shift 1			Shift 1			Shift 1		
Shift 2			Shift 2			Shift 2		
Shift 3			Shift 3			Shift 3		

PRODUCT AND PROCESS DESCRIPTION

1) What products do you make and/or what services do you provide at this facility?

____

____

____

____

____

2) What processes do you use to make these products and/or generate these services?

____

____

____

____

____

OUTAGE EXPERIENCE

In the past 12 months, about how many outages of the durations listed below have you had at this business location? Write a number in each blank. *(Use 0 if none.)*

3.1) Short duration or momentary (one minute or less) _______

3.2) Longer than one minute and up to ½ hour _______

3.3) Longer than ½ hour and up to 1 hour _______

3.4) Longer than 1 hour and up to 4 hours _______

3.5) Longer than 4 hours and up to 24 hours _______

3.6) Over 24 hours _______

MOST RECENT OUTAGE EVENTS

Please describe your three most recent power outages:

	Outage Date *Mo/Yr*	Duration *Hrs/Mins/Secs*	Time *Military*	Weather Conditions *Clear/Stormy*	Description of Impacts
3.7)	_______	_________	______	________	____
3.8)	_______	_________	______	________	____
3.9)	_______	_________	______	________	____

4) What normally happens to your facility's operations when a prolonged power outage (lasting more than one minute) occurs?
(Prompt for major equipment affected, worst effects on operations, etc.)

____

____

____

5.1) Does an outage at this location have financial effects on other sites owned by your company?
1) Yes 2) No *(if No, skip to Q5.4)*

5.2) What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?
(Probe for interdependencies of the production network.)

____

____

____

5.3) What are the specific financial effects?

____

____

____

____

5.4) Does an outage at this location have financial effects at your customers' sites?

1) Yes 2) No

6.1) Does your firm generate any of its own electricity (separate from backup power)?

1) Yes 2) No *(if No, skip to Q6.4)*

6.2) What percentage of your electrical demand is supplied by your generation equipment?

________________ %

6.3) What is the rated capacity of your generation equipment?

_____________ Circle one: kW MW hp

6.4) Does your firm have some form of backup electrical power?
1) Yes 2) No *(if No, skip to Q1C1)*

6.5) What percentage of your electrical demand could be supplied by your backup generation equipment?

________________ %

6.6) What's the rated capacity of your backup generation equipment?

_____________ Circle one: kW MW hp

The next section describes six different types of power outages. We'd like to know the costs to your business of adjusting to each of these power outages. **Assume that all of the described outages arise from issues associated with Toronto Hydro's infrastructure and occur without advance warning, which means that you don't initially know how long each outage will last.**

For many businesses, the costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. For each outage type, please estimate the costs that you'd be most likely to have under average circumstances.

Since some businesses have more than one building at one location, and others have multiple buildings in several locations, please remember to fill out these questions thinking only about the building(s) that your business occupies at the location specified for this survey.

It's important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to provide any comments about your answer.

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours

1C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2) By what percentage would activities stop or slow down? __________ %

1C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

1C4) What percent of this lost output is likely to be made up? __________ %

1C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

1C6) Damage/spoilage to raw or intermediate materials __________ $

1C7) Cost of disposing of hazardous materials __________ $

1C8) Damage to your firm's plant or equipment __________ $

1C9) Costs to run backup generation or equipment __________ $

1C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

1C11) Savings from unused raw and intermediate materials (except fuel) __________ $

1C12) Savings on your firm's fuel (electricity) bill __________ $

1C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

1C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

1C15) Labour costs to make-up lost output __________ $

1C16) Extra labour costs to restart activities __________ $

1C17) Savings from wages that were not paid __________ $

1C18) Other costs __________ $

1C19) Other savings __________ $

1C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute

2C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.2C6)

2C2) By what percentage would activities stop or slow down? __________ %

2C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

2C4) What percent of this lost output is likely to be made up? __________ %

2C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

2C6) Damage/spoilage to raw or intermediate materials __________ $

2C7) Cost of disposing of hazardous materials __________ $

2C8) Damage to your firm's plant or equipment __________ $

2C9) Costs to run backup generation or equipment __________ $

2C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

2C11) Savings from unused raw and intermediate materials (except fuel) __________ $

2C12) Savings on your firm's fuel (electricity) bill __________ $

2C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

2C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

2C15) Labour costs to make-up lost output __________ $

2C16) Extra labour costs to restart activities __________ $

2C17) Savings from wages that were not paid __________ $

2C18) Other costs __________ $

2C19) Other savings __________ $

2C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour

3C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.3C6)

3C2) By what percentage would activities stop or slow down? __________ %

3C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

3C4) What percent of this lost output is likely to be made up? __________ %

3C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

3C6) Damage/spoilage to raw or intermediate materials __________ $

3C7) Cost of disposing of hazardous materials __________ $

3C8) Damage to your firm's plant or equipment __________ $

3C9) Costs to run backup generation or equipment __________ $

3C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

3C11) Savings from unused raw and intermediate materials (except fuel) __________ $

3C12) Savings on your firm's fuel (electricity) bill __________ $

3C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

3C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

3C15) Labour costs to make-up lost output __________ $

3C16) Extra labour costs to restart activities __________ $

3C17) Savings from wages that were not paid __________ $

3C18) Other costs __________ $

3C19) Other savings __________ $

3C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours

4C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.4C6)

4C2) By what percentage would activities stop or slow down? __________ %

4C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

4C4) What percent of this lost output is likely to be made up? __________ %

4C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

4C6) Damage/spoilage to raw or intermediate materials __________ $

4C7) Cost of disposing of hazardous materials __________ $

4C8) Damage to your firm's plant or equipment __________ $

4C9) Costs to run backup generation or equipment __________ $

4C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

4C11) Savings from unused raw and intermediate materials (except fuel) __________ $

4C12) Savings on your firm's fuel (electricity) bill __________ $

4C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

4C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

4C15) Labour costs to make-up lost output __________ $

4C16) Extra labour costs to restart activities __________ $

4C17) Savings from wages that were not paid __________ $

4C18) Other costs __________ $

4C19) Other savings __________ $

4C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours

5C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.5C6)

5C2) By what percentage would activities stop or slow down? __________ %

5C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

5C4) What percent of this lost output is likely to be made up? __________ %

5C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

5C6) Damage/spoilage to raw or intermediate materials __________ $

5C7) Cost of disposing of hazardous materials __________ $

5C8) Damage to your firm's plant or equipment __________ $

5C9) Costs to run backup generation or equipment __________ $

5C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

5C11) Savings from unused raw and intermediate materials (except fuel) __________ $

5C12) Savings on your firm's fuel (electricity) bill __________ $

5C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

5C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

5C15) Labour costs to make-up lost output __________ $

5C16) Extra labour costs to restart activities __________ $

5C17) Savings from wages that were not paid __________ $

5C18) Other costs __________ $

5C19) Other savings __________ $

5C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

6C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.6C6)

6C2) By what percentage would activities stop or slow down? __________ %

6C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

6C4) What percent of this lost output is likely to be made up? __________ %

6C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

6C6) Damage/spoilage to raw or intermediate materials __________ $

6C7) Cost of disposing of hazardous materials __________ $

6C8) Damage to your firm's plant or equipment __________ $

6C9) Costs to run backup generation or equipment __________ $

6C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST

6C11) Savings from unused raw and intermediate materials (except fuel) __________ $

6C12) Savings on your firm's fuel (electricity) bill __________ $

6C13) Scrap value of damaged products or inputs __________ $

LABOUR COST

6C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

6C15) Labour costs to make-up lost output __________ $

6C16) Extra labour costs to restart activities __________ $

6C17) Savings from wages that were not paid __________ $

6C18) Other costs __________ $

6C19) Other savings __________ $

6C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

7.1) Now that we have discussed the *direct* costs associated with these outages, would you experience any *intangible* costs such as loss of good will, potential liability, or loss of future customers?

1) Yes (*if Yes, please explain)*
2) No

____

____

____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

8.1) If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro?

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your business will help us understand how power outages affect your type of business. Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9.1) Which one of the following categories best describes your business?

- ❑ Agriculture/Agricultural Processing
- ❑ Assembly/Light Industry
- ❑ Chemicals/Paper/Refining
- ❑ Food Processing
- ❑ Grocery Store/Restaurant
- ❑ Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ High Tech
- ❑ Lumber/Mining/Plastics
- ❑ Office
- ❑ Oil/Gas Extraction
- ❑ Retail
- ❑ Stone/Glass/Clay/Cement
- ❑ Transportation
- ❑ Utility
- ❑ Other *(please specify)*: ______________________________

9.2) What's the approximate square footage of the facility?

__________ Square feet

9.3) How many **full-time** (30+ hours per week) employees are employed by your business at this location?

__________ Full-time employees

9.4) List the number of people employed by your business at this location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

9.5) What's the approximate value of your business' annual operations or services (income)?

$_____________ per year

9.6) What's the approximate value of your business' total annual expenses (including labour, rent, materials, and other overhead expenses)?

$_____________ per year

9.7) Approximately what percentage of your business' annual operating budget is spent on electricity?

__________ %

That concludes our interview today. Thank you very much for your time.

Please have customer sign / initial below acknowledging receipt of the $150 cheque.

Customer Name: ____ Date: _____________________

FOR INTERNAL USE ONLY:

Based on your observations of this facility, give a brief summary of the facility, any freak occurrences with their power supply, and the critical factors that minimize and/or exacerbate outage costs.

____

____

____

____

____

____

____

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D4 Capacity Planning, Growth & Electrification

Toronto Hydro's capacity plan ensures that the distribution system is adequately sized to deliver reliable electricity to the utility's customers. To that end, the capacity planning process considers new load connections, increased distributed energy resources ("DERs") and broader electrification activities including the electrification of transportation. Fundamental to the capacity planning process is a 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") that is developed using a driver-based forecasting methodology. The System Peak Demand Forecast is the basis for the Regional Planning forecast at the needs assessment stage to assess the adequacy of transmission facilities to supply the distribution grid.[1]

Capacity planning is becoming more complex as utilities address the unprecedented energy transition that is set to unfold over the coming years. National, provincial, and municipal decarbonization targets, as well as technical, societal, and economic factors are driving toward a decarbonized, decentralized and digitized energy system. This shift is expected to expand the role of clean electricity as source of energy for transportation and heating. Despite explicit industry and government net zero emission targets, there are still degrees of uncertainty around how these ambitious goals will be achieved. The pace and timing of the resulting growth and electrification from the pursuit of these targets will be driven by a complex interplay of policy, technological developments and consumer choice. Distribution system capacity planning must manage these interlinked growth drivers in an environment of greater uncertainty. Section D4.3 provides an overview of how Toronto Hydro has addressed this complexity and managed this uncertainty in its investment planning for 2025-2029.

For the 2025-2029 rate period, Toronto Hydro undertook enhanced capacity and connections capability assessments to monitor capacity related risks within its system. The enhancements include the preparation of the System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth.

Toronto Hydro also augmented its decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from

[1] Please refer to Exhibit 2B, Section B for more information about Toronto Hydro's role in the Regional Planning Process.

the System Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, the Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050. The Future Energy Scenarios is described in more detail in Appendix A to this schedule.

This Exhibit describes Toronto Hydro's approach to capacity planning for 2025-2029 and is organized into the following sub-sections:

- **Section D4.1** outlines the capacity planning approach,
- **Section D4.2** describes in impact of growth and electrification considerations on the capacity planning process, and
- **Section D4.3** describes capacity needs and investments over the 2025-2029 period.

D4.1 Capacity Planning

Through its capacity planning process, Toronto Hydro assesses the adequacy of the distribution grid to deliver safe and reliable electricity to current and future customers. This process is linked with Regional Planning to ensure the adequacy of transmission facilities supplying the distribution grid. The System Peak Demand Forecast is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage.

D4.1.1 System Peak Demand Forecast

The System Peak Demand Forecast determines the grid capacity investments that Toronto Hydro needs to make in the 2025-2029 rate period in order to continue to serve its customers and support economic growth and development in the City of Toronto. Using a probabilistic approach to forecast the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid, the System Peak Demand Forecast yields summer and winter demand peaks, with the summer peak driving the 2025-2029 investment plan.

To arrive at the System Peak Demand Forecast, Toronto Hydro modelled organic system growth as part of the base forecast along with specific drivers that are relevant and material to the planning horizon. More specifically, Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. Each of these drivers is discussed in further detail below.

The System Peak Demand Forecast methodology includes the following components and considerations:

1. Weather Normalization
2. Econometric Multivariate Regression
3. Hyperscale Data Centre Demand Driver Analysis
4. Electric Vehicle (EV) Demand Driver Analysis
5. Municipal Energy Plans – Uncommitted Connections
6. Monte-Carlo Simulation
7. TS Bus Growth Allocation & Layering of Load Transfers/Voltage Conversions and Customer Connections

D4.1.1.1 Weather Normalization

To determine the correlation between temperature and load, Toronto Hydro’s analysis removed the impact of day-to-day fluctuations in temperature on peak load in order to arrive at a stable view of historical system performance. Toronto Hydro then applied the historical trend to the forecasted peak load to normalize the forecast for weather-related impacts.

D4.1.1.2 Econometric Multivariate Regression

In addition to weather, Toronto Hydro considered a range of macroeconomic assumptions as inputs to the System Peak Demand Forecast, including the following key variables:

1. Toronto Population
2. Toronto Employment Rate & Median Income
3. Consumer Price Index
4. Number of Business Licenses Issued/Renewed
5. Toronto Housing Starts
6. Average Home Price

Toronto Hydro relied on traditional forecasting approaches to establish a correlation between weather and peak demand, and between econometric variables and peak demand. Toronto Hydro enhanced the traditional approach by incorporating considerations of the impact of varying weather on economic activity and its relationship to peak demand. This analysis enabled the utility to assess the impact of a changing climate on the econometric variables that affect peak demand.

D4.1.1.3 Hyperscale Data Centre Demand Driver Analysis

Toronto Hydro identified hyperscale data center connections as a new driver of significant peak demand growth over the 2025-2029 rate period and beyond. A hyperscale data center supports large processing and data storage operations using 5,000 servers or more and has the capability of a peak demand exceeding 25 MW. In order to better understand the impact of hyperscale data center connections on the grid and plan accordingly, Toronto Hydro modelled this driver separately. Through review of historical load connections, research into growth rates for comparable North American cities, and assessments of vacancy rates as well as available land space in the City, Toronto Hydro assessed the peak demand contributions of hyperscale data centers.

D4.1.1.4 Electric Vehicle Demand Driver Analysis

Toronto Hydro forecasted the impact of light-duty, medium-duty and heavy-duty EVs. Figure 1 below summarizes the volumes of EVs that underpin the forecast. The adoption models are aligned with the City of Toronto’s Transform TO transportation electrification goals. The forecast also considered geographic distribution and typical charging profiles to arrive at area and system peak demand contribution from electric vehicle uptake by consumers.

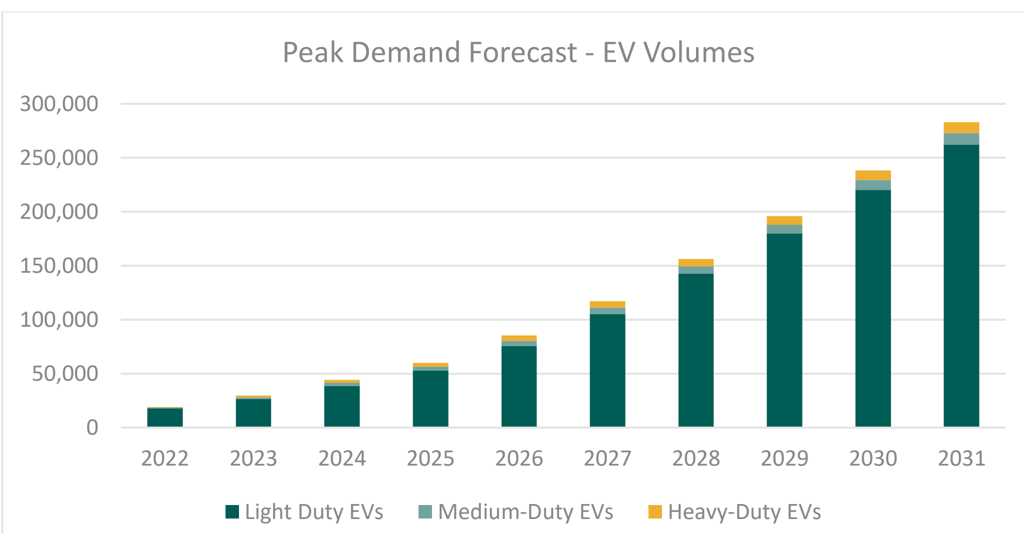

Figure 1: Peak Demand Forecast – EV Volumes

D4.1.1.5 Municipal Energy Plans

In the development of the System Peak Demand Forecast, Toronto Hydro considered the impact of Municipal Energy Plans for large projects, such as the re-development of Downsview, Port Lands and Scarborough Golden Mile.[2] Figure 2, shows the location of these projects in the city.

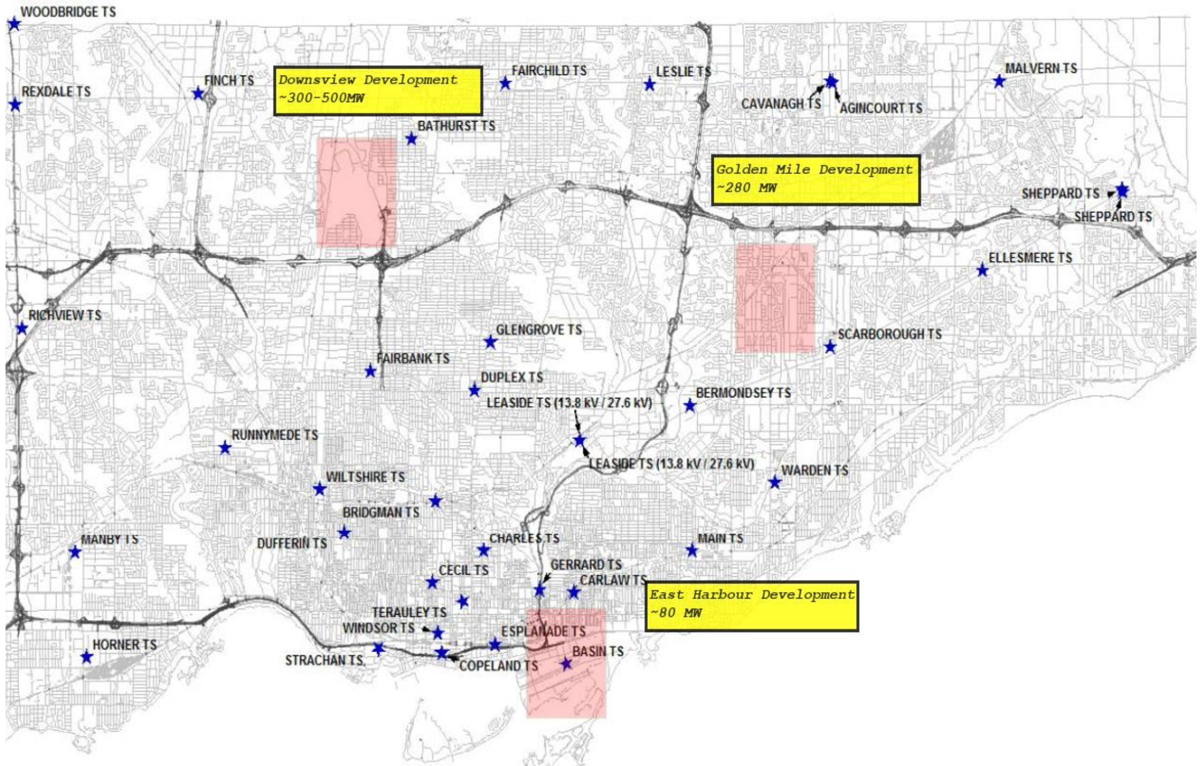

Figure 2: Municipal Energy Plan Locations

For the identified Municipal Energy Plans, Toronto Hydro included both firm connection commitments and the anticipated future loads in the System Peak Demand Forecast to ensure that the utility has sufficient lead-time to invest in new grid capacity that is required to serve this future demand. This approach is consistent with section 3.3.1 of the Distribution System Code which requires distributors to "plan and build the distribution system for reasonable forecast load growth." It is also aligned with the recommendation of the OEB's Regional Planning Process Advisory Group for distributors to incorporate Municipal Energy Plan information into their planning and forecasting

[2] City of Toronto, Official Plans – Secondary Plans, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/chapter-6-secondary-plans/

processes in order to "identify current and future needs for new electricity infrastructure investments within local communities."[3]

D4.1.1.6 Monte-Carlo Simulation

Monte-Carlo Simulation is a sophisticated modelling technique that is applied to model the probability of different outcomes when the potential for random variables is present. It considers multiple sources of uncertainty to provide a range of possible outcomes for peak demand. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

D4.1.1.7 TS Bus Growth Allocation and Layering of Load Transfers/Voltage Conversions and Customer Connections

The final step in the forecasting process involves allocating the demand outputs from each driver to the station buses and layering on any permanent load transfers through the Load Demand program to arrive at the System Peak Demand Forecast that describes impacts at both a system and bus level.

D4.1.2 Regional Planning Needs Assessment Forecast

The Toronto regional planning process commenced in the fall of 2022 with the needs assessment phase.[4] The transmitter Hydro One Networks Inc. develops the regional planning needs assessment forecast using an extreme weather model, information from Toronto Hydro's System Peak Demand Forecast and a forecast of Conservation and Demand Management (CDM) and Distributed Generation (DG) from the IESO.

The Needs Assessment Report issued in December 2022 indicates that the net summer peak demand in the Toronto region is expected to increase by an average of 2.1 per cent per year, reaching 6800 MVA by 2031.[5] Figure 3 below shows Toronto Hydro's System Peak Demand Forecast and the Regional Planning Forecast issued by Hydro One. The System Peak Demand Forecast is shown net of the forecasted impacts of CDM and DG. The primary difference between the System Peak Demand

[3] RPPAG, Municipal Information Document – Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector, (December 15, 2022) p. 2, "online", https://www.oeb.ca/sites/default/files/RPPAG-Municipal-Information-Document-20221202.pdf
[4] Exhibit 2B, Section B
[5] Exhibit 2B, Section B, Appendix A – Needs Assessment Report (Toronto Region)

Forecast and Regional Planning Needs Assessment forecast is the effect of extreme weather. As noted above, Toronto Hydro normalizes its forecast for weather fluctuations, whereas the Regional Planning Needs Assessment forecast relies on an extreme weather model. Figure 3 shows that Toronto Hydro's grid capacity needs to increase by at least 23% by the next decade.

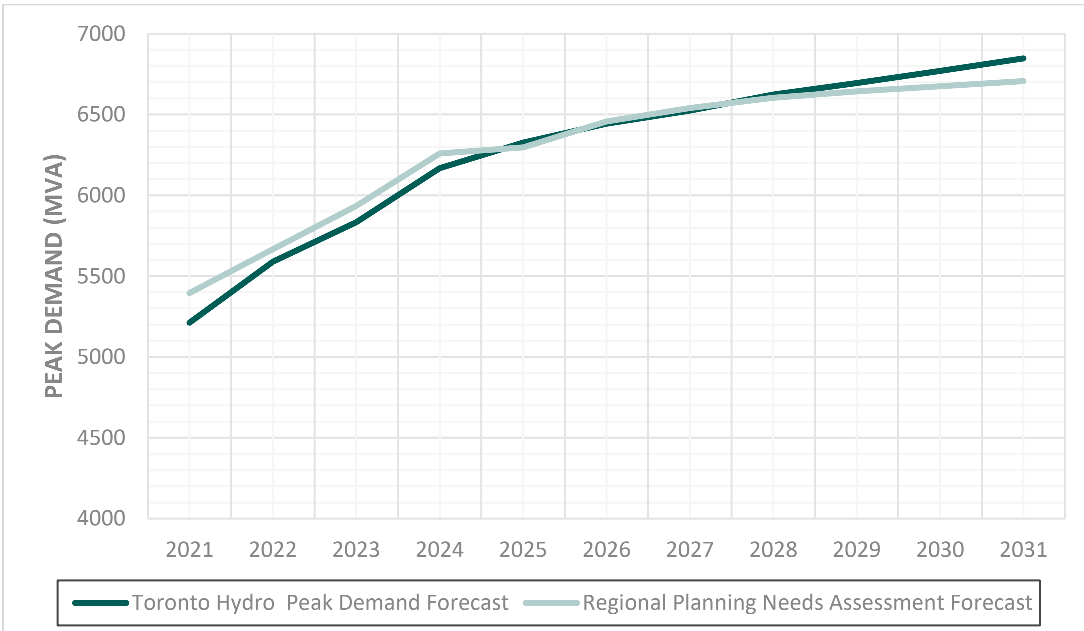

Figure 3: Toronto Hydro System Peak Demand Forecast and the Regional Planning Needs Assessment Forecast prepared by Hydro One

D4.1.3 Connection Capability

In order to connect new customers, Toronto Hydro needs grid capacity as well as spare feeder positions (i.e. feeder breakers to which new feeders can be connected). As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply the required demand, if there are no feeder positions to connect new feeders to the station, the station is unable to support new connections. To this end, Toronto Hydro must monitor the number of spare feeder positions at its stations to maintain the ability to connect new customers. When new feeders are needed and there are spare feeder positions are available, Toronto Hydro initiates projects in the Load Demand program to transfer feeder loads and free up feeder positions so that new customers can connect to the system in a timely and efficient manner.

D4.1.4 Generation Capacity and Capability Assessment

Toronto Hydro connects DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. As part of its capacity planning process, the utility identified a number of constraints that impact DER connections to the distribution grid, including:

- limited breaker and station equipment capacity due to short circuit capacity constraints;
- reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
- anti-islanding conditions for DG; and
- system thermal limits and load transfer capability.

Short circuit capacity constraints on station equipment are the primary constraint for DER connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DERs on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new DER application to monitor the available existing short circuit capacity of the system.

D4.2 Capacity Planning and the Energy Transition

The decarbonization of the energy system to mitigate the existential and economic impacts of climate change is expected to create new roles for electricity, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes are driven by a complex interplay of policy, technological developments and consumer choice. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). To contend with this uncertainty and complexity in its planning process, Toronto Hydro developed the Future Energy Scenarios modelling tool to understand possible changes to future peak demand under different scenarios. For more information about this tool please refer to Appendix A.

In order to be able to continue to deliver its central purpose of serving the electricity needs of the residents, businesses and institutions in the City of Toronto, the utility must take responsible actions in the 2025-2029 plan period to prepare the local grid and its operations for the unprecedented energy transition that is and will continue to gradually unfold across the economy. At the same time, the exact path and pace of the energy transition remains subject to various factors of uncertainty (policy, technology and consumer behavior), which means that Toronto Hydro must be careful to ensure that investments being made in the 2025-2029 rate period provide long-term value to customers and enable policy, technology and customer choice in effecting the energy transition. To balance both of these objectives, Toronto Hydro adopted a "least regrets" planning philosophy. The term "least regrets" refers to a strategic planning approach anchored in the decision-making theory of anticipating and minimizing regretful choices/outcomes when faced with uncertainty.

As part of its capacity planning process, Toronto Hydro took the following actions to identify least regrets investments in the 2025-2029 rate period:

- included additional drivers in its System Peak Demand Forecast (e.g. EVs, data centers and Municipal Energy Plans) to assess the anticipated future demand;
- augmented its decision-making process with the results of a Future Energy Scenarios model to understand the impact of different policy, technology and consumer behavior drivers; and
- used the Future Energy Scenarios to stress-test whether the utility's capacity plan can accommodate energy transition needs (e.g. building heating electrification) in the early part of the next decade, if required.

The Future Energy Scenarios reveal that the impact of building electrification in the next two decades could be significant from a system peak demand perspective, but that there are notable differences (driven by policy, technology and consumer-behaviour choices) as to when and how building electrification could unfold. For example, the Consumer Transformation scenario of the Future Energy Scenario shows that localized consumer-focused technology solutions such DERs (including energy efficiency) could materially curtail the annual peak demand curves in a future where buildings are increasingly electrified. In light of these circumstances, "least regrets" meant Toronto Hydro acted with a higher degree of caution in terms of building new capacity to prepare the distribution grid for wide-scale building electrification in the next two decades, as the policy and consumer-behaviour drivers of this type of demand remain uncertain, and technology advancement could offer more cost-effective solutions in the future. Practically, this meant that Toronto Hydro decided to take a "wait and see approach" to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond.

Toronto Hydro's "least regrets" investment approach to growth and electrification is reinforced by the utility's Grid Modernization strategy summarized in Exhibit 2B, Section D5.

Toronto Hydro's traditional grid infrastructure is facing a shift driven by renewable energy integration, technology evolution, changing customer needs, and more. The Grid Modernization Strategy recognizes the need to prepare for these transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

Key elements of this investment strategy include investments in Non-Wires Solutions – such as contracted demand response ("Flexibility Services") and grid-scale renewable-enabling battery energy storage systems ("REBESS") – as well as major investments in the development of a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into operations, provide Toronto Hydro with an enhanced capability to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid.

D4.3 Capacity Needs and Investment Plan

As noted above, the primary drivers of capacity need and related investments over the 2025-2029 rate period are: customer connections (included as part of the base forecast), electrification of transit, electric vehicles, hyperscale data centers, and Municipal Energy Plans for three regions of the city discussed above. Figure 4 below shows the contribution of each of these drivers to the System Peak Demand Forecast.

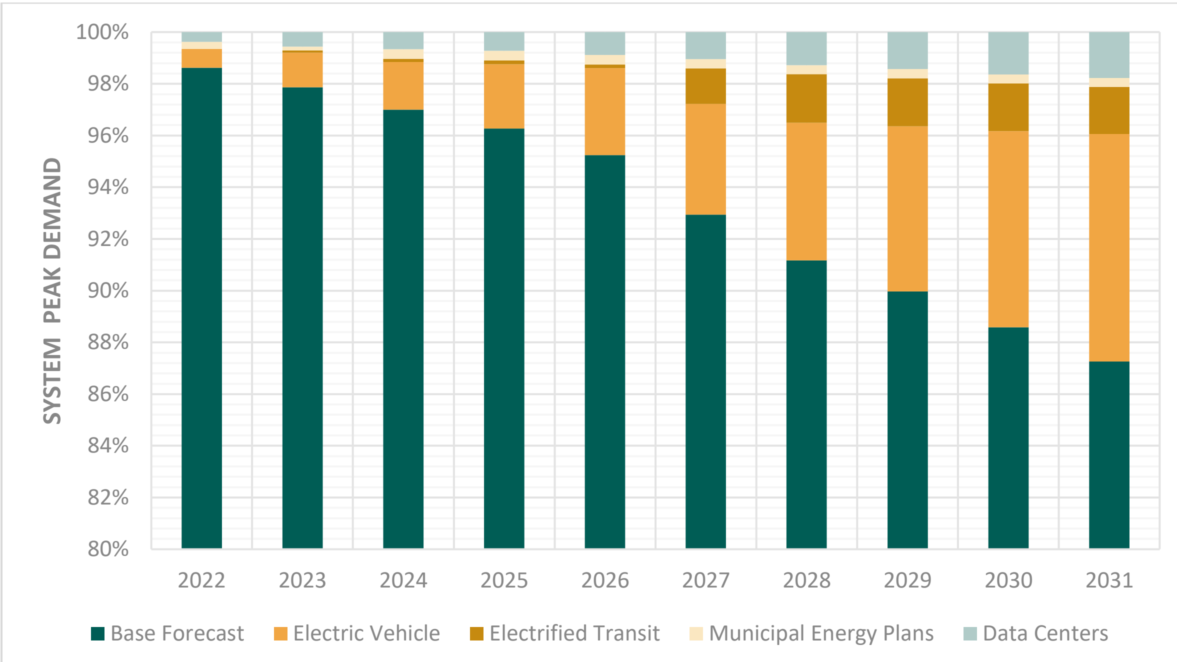

Figure 4: Toronto Hydro System Peak Demand Forecast by Driver

In the development of the System Peak Demand Forecast, Toronto Hydro determined that building electrification (i.e. electrification of space and water heating) is not yet a significant driver of growth in the 2025-2029 rate period. As a result, the System Peak Demand Forecast continues to be a summer peaking forecast. However, to stress test the assumptions regarding building electrification against the least regrets planning philosophy, Toronto Hydro assessed whether the utility could accommodate a growing winter peak (driven by building electrification) in the 2025-2029 rate period if needed. To that end, the utility looked at scenarios of forecasted building heating loads derived from the Future Energy Scenario model outputs. More specifically, Toronto Hydro used the Consumer Transformation scenario, and its low efficiency equivalent, as the lower and upper bounds, of the sensitivity test.

The Consumer Transformation scenario models an energy transition pathway where consumers play a prominent role in driving results towards decarbonization. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. In the related low efficiency Consumer Transformation scenario, the uptake of electrified heat and transport technologies is the same, but the uptake of efficiency measures (e.g. building retrofits), and DERs (e.g. renewables and energy storage) is limited resulting in a higher peak demand. Toronto

Hydro selected the Consumer Transformation scenario and its low efficiency equivalent for this sensitivity analysis because these scenarios presented (i) the most variability in building heat, between the high and low efficiency assumptions, and (ii) the most material grid impact of the energy transition in terms of system peak demand.

Figure 5 below compares the Regional Planning Needs Assessment Forecast, System Peak Demand Forecast and the selected upper and lower bounds of the Consumer Transformation scenario.

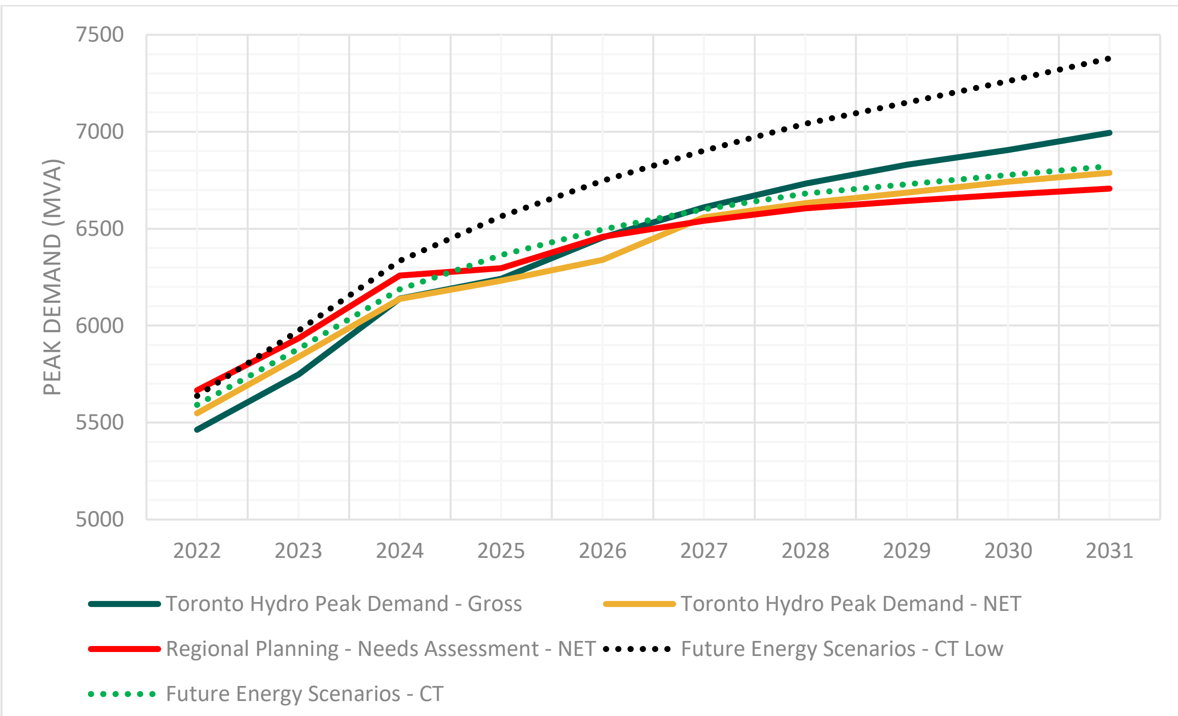

Figure 5: Comparison of Planning Forecasts and Future Energy Scenarios

As shown in Figure 5 above, Toronto Hydro's System Peak Demand Forecast is generally aligned with the Consumer Transformation (CT) scenario. From this analysis, Toronto Hydro concluded that the capacity investment plan can meet higher levels of building heating loads (which contribute to winter peak) should this driver of electrification materialize at a faster pace than expected. As a result, Toronto Hydro has confidence that the investments in system capacity that the utility proposes to make in the 2025-2029 rate period are least regrets to address growth and electrification drivers that the utility faces in this decade and the early part of the next decade. That being said, it is possible that the utility could be faced with incremental capacity constraints at a localized level as a result of accelerated transportation and building electrification demand. To address this challenge, the utility proposes a Demand Related Variance Account to track variances in actual versus forecasted expenditures in a number of demand-related investment programs. For more information about this proposal please refer to Exhibit 1B, Tab 2, Schedule 1.

Based on the capacity planning process outlined above, Toronto Hydro proposes investments in various programs to meet the utility's fundamental obligation to connect new and expanded services to the grid in this decade and beyond. These programs include expansion to increase grid capacity and enhancements to better utilize existing equipment. Through programs such as Load Demand[6], Stations Expansion[7], and Horseshoe and Downtown Renewal[8], Toronto Hydro is renewing and enhancing stations, buses, feeders, and other equipment that will facilitate load growth at the appropriate locations. In areas where Toronto Hydro expects customers to connect more DERs, programs such as Grid Protection, Monitoring and Control alleviate short-circuit capacity constraints.[9] Furthermore, where feasible and cost-effective, Toronto Hydro's intends to leverage the Non-Wires Solutions program to (i) procure market-based flexibility services to avoid or defer capital investment, and (ii) deploy grid-scale storage solutions to enable the connection of renewable energy generation facilities.[10]

The sections that follow discuss in more detail the capacity investments that Toronto Hydro intends to make in key areas of the grid.

D4.3.1 Downtown Area

Figure 6 below shows all transformer stations in the Downtown area. Areas in green represent transformer stations that do not require relief within 10 years. The transformer stations in yellow require bus relief between 5 to 10 years while the transformer stations in red, require bus relief within 5 years.

[6] Exhibit 2B, Section E5.3
[7] Exhibit 2B, Section E7.4
[8] Exhibit 2B, Section E6.2 and Section E6.3
[9] Exhibit 2B, Section E5.5.
[10] Exhibit 2B, Section E7.2.

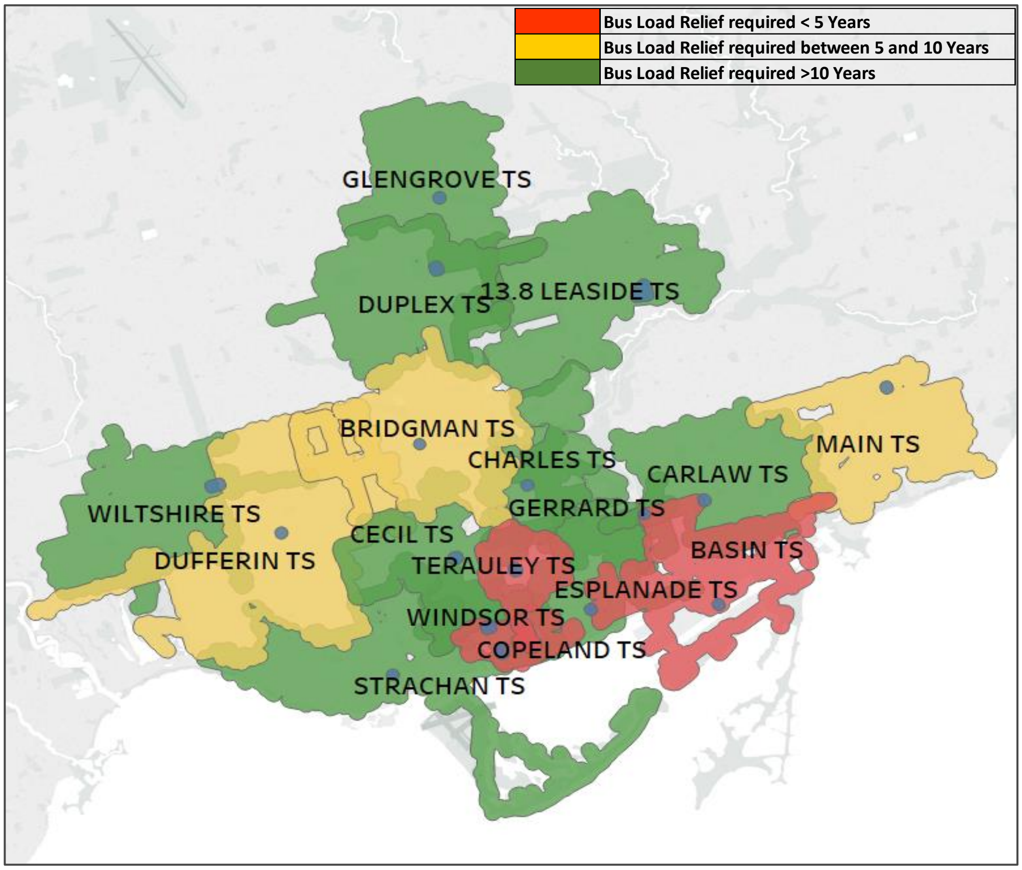

Figure 6: Downtown stations requiring load relief

Toronto Hydro expects that the stations in the south east region of the downtown core will be out of spare feeder positions and become capacity-constrained before the end of the decade, mainly due to the increase in demand from the Port Lands and East Harbour developments.

The Port Lands development is a flood protection project in the southeast of Toronto's downtown core and includes over 715 acres of land along the waterfront. In addition to creating a naturalized river valley for the Don River, this project involves building new public spaces, roads, bridges and municipal infrastructure. Once the flood protection work is complete, development of a planned community on Villiers Island between Cherry Street and Don Roadway is expected to begin.

The East Harbour development, described in the City's Unilever Precinct Secondary Plan, represents 25 hectares of lands located directly to the east of Downtown Toronto. The area is bordered by Lake Shore Boulevard to the south, Booth Avenue to the east, Eastern Avenue to the North and the Don

River to the west. It is also the site of a future rapid transit hub that will accommodate a subway station for the Downtown Relief Line.

The stations most impacted by this growth are the Basin Transformer Station ("Basin TS") and Esplanade Transformer Station ("Esplanade TS"). The Load Demand program addresses capacity limitations at both stations in the short term. Toronto Hydro intends to increase capacity at Basin TS by upgrading existing infrastructure to support the Port Lands and East Harbour Developments and manage near-term capacity shortfalls. The Copeland Phase 2 expansion provides load relief to both Esplanade TS and Basin TS, in addition to alleviate constraints at Copeland TS. For further details please refer to the Stations Expansion program in Section E7.4

D4.3.2 Horseshoe East Area

The Scarborough area in the Horseshoe East experienced significant load growth in recent years, and Toronto Hydro expects this trend to persist due to the development of the Golden Mile corridor, the Ontario Line, and the Scarborough subway extension. In particular, the Golden Mile Secondary Development Plan covers an area of 113 hectares of land in Scarborough bordered by Ashtonbee Road to the north, Birchmount Road to the east, Civic Road / Alvinston Road to the south and Victoria Park Avenue to the west. Taking these drivers into account, Toronto Hydro forecasts average growth of 4.1% per year over the next 10 years in the Horseshoe East Area. To that end, the System Peak Demand Forecast shows that the areas is expected to reach more than 90% of its capacity by 2031. Figure 7 highlights the load relief required in the short term. Toronto Hydro plans to provide capacity relief to the area by expanding Scarborough TS. Please refer to the Stations Expansion Program in Exhibit 2B, Section E7.4 at Appendix B for additional details about this project.

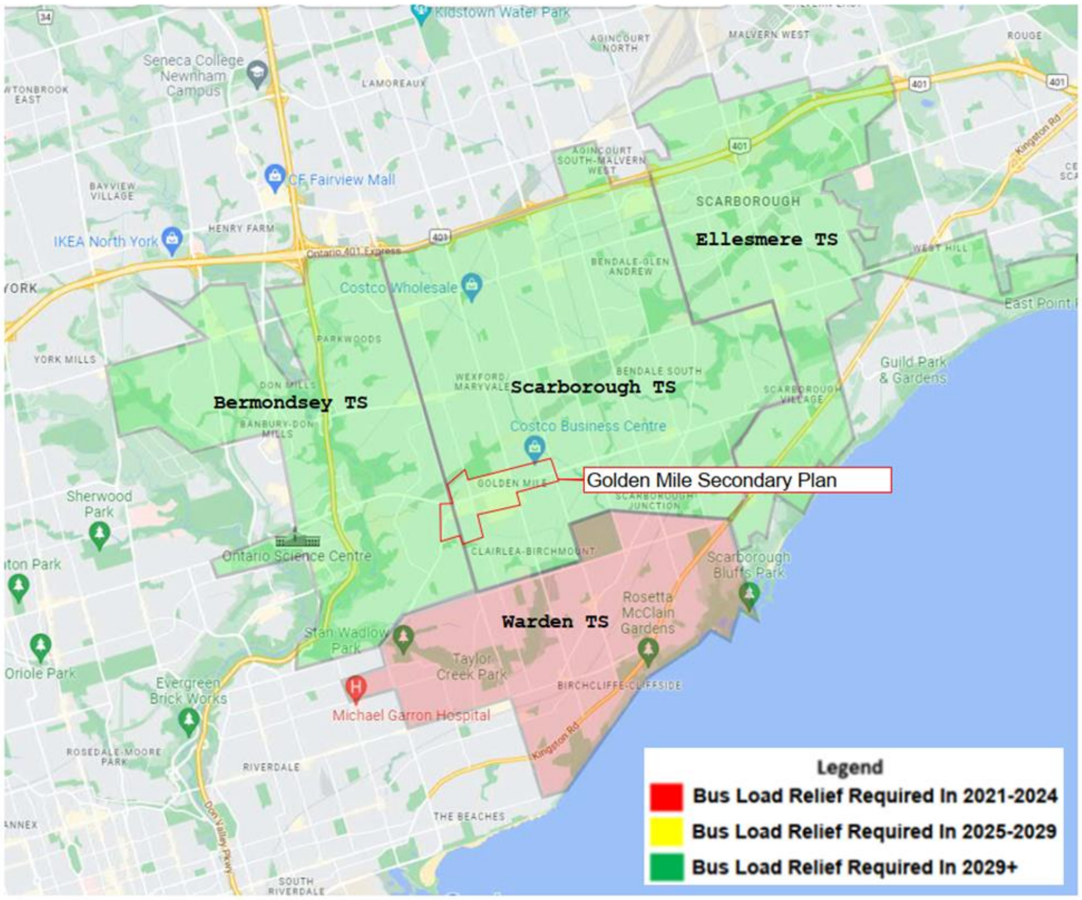

Figure 7: Scarborough TS and East Region

D4.3.3 Horseshoe West Area

The Horseshoe West is also expected to experience notable load growth over the next decade, resulting in a forecasted average peak demand growth of 2.2% per annum. The System Peak Demand Forecast indicates that the majority of stations in this area are expected to reach capacity in the next decade or shortly thereafter. Moreover, by the end of the decade, Toronto Hydro forecasts the entire area to be highly loaded at 90% capacity. The region surrounding the Downsview area (shown in Figure 8 below) is expected to see the highest growth due to redevelopment of this area.

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan, covering 210 hectares, bounded by Sheppard Avenue to the north, Allen Road to the east, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 9.

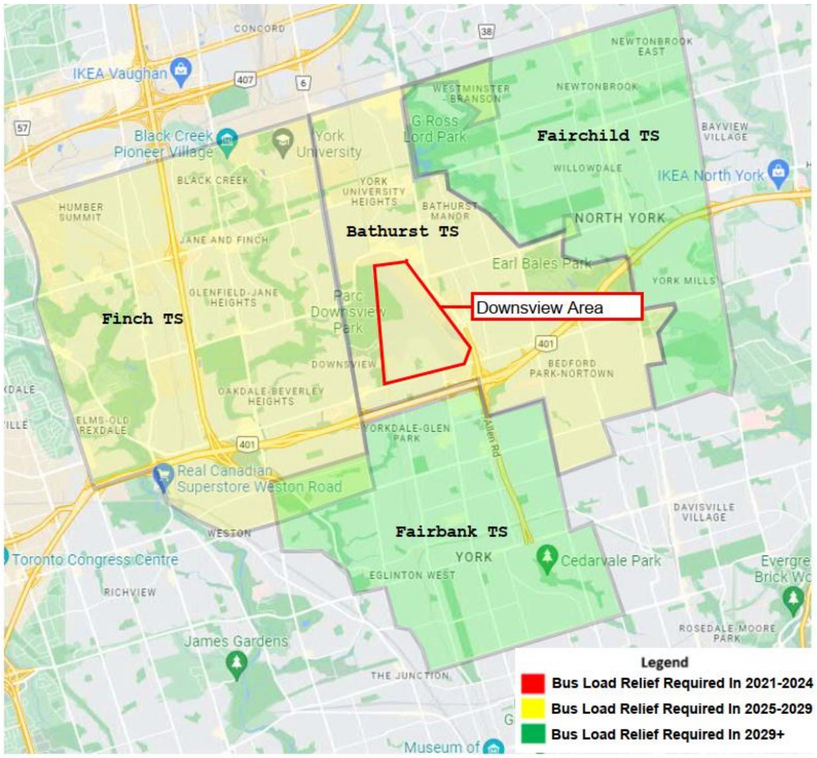

Figure 8: Downsview Area and surrounding stations

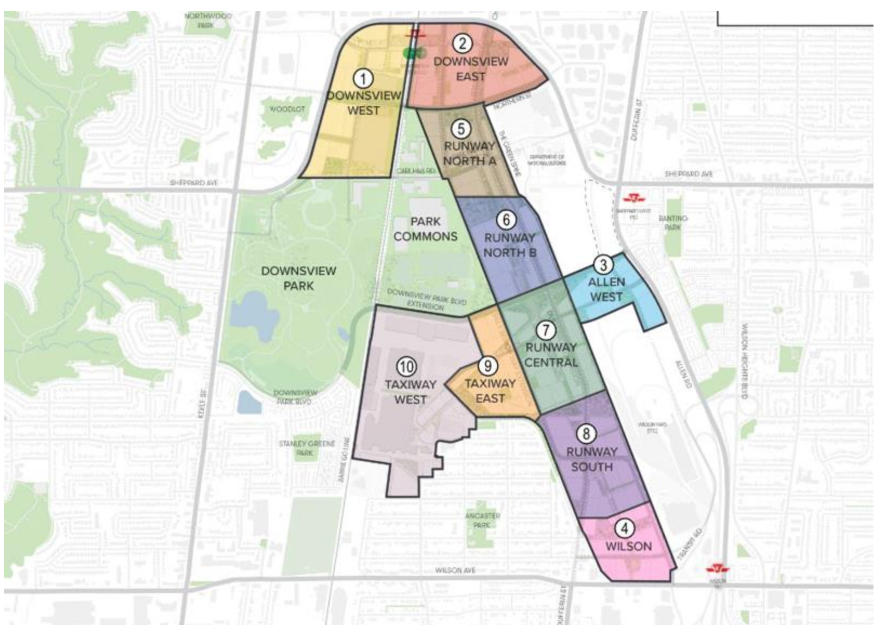

Figure 9: Downsview Area Secondary Plan

The Downsview Area Secondary Plan includes plans to expand each district with a mix of commercial, office, industrial and institutional buildings. The Allen East District is planned for a residential development of approximately 3,500 dwelling units. Load in the Downsview area is expected to reach 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051.[11] Based on this growth, the System Peak Demand Forecast shows that three of the four stations (Bathurst, Fairbank, Finch) in the region surrounding the Downsview Area (Figure 9) are expected to reach their capacity within a short period of one another, in 2030-2036. Fairchild TS is the only station in the region with available capacity (until 2041), but due to geographical constraints, it can only provide direct relief to Bathurst TS.

Load relief is needed at a regional level to support new connections, demand-growth, and electrification in the Horseshoe West area. Through the Toronto Regional Planning process, the utility proposes to construct a new transformer station (Downsview TS) to address this need. Please refer to the Stations Expansion Program at Exhibit 2B, Section E7.4 for more information.

[11] Exhibit 2B, Section E7.4.3.1 – Downsview TS.

Appendix A – Future Energy Scenarios Overview

The energy landscape is undergoing a fundamental shift driven by decarbonization mandates to mitigate the life-threatening impacts of climate change. This shift is expected to create new roles for electricity in the day-to-day energy needs of consumers, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes will be driven by a complex interplay of policy, technological developments and consumer choice.

While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). This reality means that planning is becoming more complex for distributors like Toronto Hydro who must manage various interlinked growth drivers in an environment of greater uncertainty.

Future Energy Scenarios is a modelling tool that explores a range of possible changes to future peak demand based on the interplay of different policy, technology and consumer behaviour assumptions. This scenario-based approach embraces the uncertainty and variability of the energy transition and reveals possible pathways of change.

1 Public Policies and Objectives

Government at all levels are implementing decarbonization policies, including GHG emission targets and incentives to encourage consumers to electrify their transportation and heating needs. Key policies and incentives include:

Canada Greener Homes Grant provides up to $5,000 for electrified heating technologies such as heat pumps.[1] This grant was introduced in December 2020 and is expected to stay in place for seven years.

Incentives for Zero-Emissions Vehicles ("iZEV") program provides up to $5,000 for electric and hydrogen-fueled vehicles until March 2025.[2]

[1] Natural Resources Canada, Canada Greener Homes Grant, "online", https://www.nrcan.gc.ca/energy-efficiency/homes/canada-greener-homes-initiative/canada-greener-homes-grant/canada-greener-homes-grant/23441
[2] Transport Canada, Incentives for Zero-Emission Program, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/light-duty-zero-emission-vehicles/incentives-purchasing-zero-emission-vehicles

The Ontario Energy Board, working with distributors, recently implemented a **"Ultra-Low Overnight" rate option** to incentivize off-peak EV charging to encourage the uptake of EVs as an alternative to the rising fuel costs of internal combustion vehicles.[3]

Federal Zero Emission Vehicle Sales Targets: The federal government has committed to a mandatory 100% zero-emission vehicle sales target by 2030 for all new light-duty vehicles.[4]

City of Toronto's **Toronto Green Standard** sustainable design and performance requirements for new private and city-owned developments. The most recent version all but eliminates the use of natural gas in new buildings.[5]

Federal carbon pollution pricing system: Since 2019, every jurisdiction in Canada has had a price on carbon pollution, including a charge on fossil fuels like gasoline and natural gas. The fuel charge increases annually in relation to the carbon pollution price. The carbon pollution price will increase from $65 per tonne of carbon dioxide equivalent in 2023 to $170 per tonne by 2030.[6]

Many commercial and industrial customers in Toronto Hydro's service territory have adopted decarbonization and emissions reduction goals through Environmental, Social and Governance ("ESG") mandates. In an engagement with Key Account customers that Toronto Hydro completed in advance of preparing the 2025-2029 investment plan, the utility found that approximately 64% of the customers surveyed have plans to decarbonize their business and expect Toronto Hydro to support them by ensuring that the grid has sufficient capacity to serve their needs.[7]

1.1 Technological Advancements

Technological advancements are providing customers more choice in respect of their energy needs, and over time these choices can have significant impacts for the distribution grid. According the

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[3] Province of Ontario, Ontario Launches New Ultra-Low Overnight Electricity Price Plan, "online", https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[4] Transport Canada, Canada's Zero-Emission Vehicle (ZEV) sales targets, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/canada-s-zero-emission-vehicle-zev-sales-targets.

[5] City of Toronto, Toronto Green Standard, Version 4, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/.

[6] Government of Canada, How carbon pricing works, "online", https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution.html; Government of Canada, Canada Revenue Agency. Fuel Charge Rates, "online", https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

[7] Exhibit 1B, Tab 3, Schedule 1 – Customer Engagement p. 18-19.

National Renewable Energy Laboratory's cost benchmarking studies, installed system costs per watt for solar PV from 2010 to 2020 have sharply decreased by 64% for a residential 7-kW rooftop system and 69% for a commercial 200-kW rooftop system.[8] Stand alone battery energy systems (BESS) experienced a similar 10% cost decline from 2020 to 2021.[9] The declining cost curves of these technologies are providing customers more economical choices to invest in distributed energy resources. Similarly, efficiency improvements in heat pumps are making these technologies more feasible alternatives to natural gas furnaces for space heating in cold weather climates.

1.2 Consumer Choices

Consumer choices and behaviors regarding energy use are gradually changing. Activities that previously did not affect the electricity system (including fueling vehicles and space heating) now have the potential to change electricity consumption patterns and shift system peaks. For example, residential and fleet EV charging could create new system needs like real-time voltage control to support a sharp rise from morning and/or afternoon charging on a scale similar to that created by air conditioning demand on hot summer days. Additionally, as heating systems are electrified (e.g. heat pumps), electricity system peaks can shift from summers to winters.

1.3 Future Energy Scenarios Framework

To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy,[10] to develop the Future Energy Scenarios modelling tool. This is the first pathway study in Ontario to focus on the distribution-level impacts of the energy transition. The model was informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, data sets and policy. Emissions were not directly modelled in the Future Energy Scenarios, but policies and targets were built into the tool such that the key drivers are consistent with emissions goals.

Future Energy Scenarios employs bottom-up consumer choice and willingness-to-pay models which are based on the concept that consumers try to maximize their utility when making decisions. For example, in the case of different heating technologies, when a homeowner is deciding to replace a

[8] NREL, Solar Installed System Cost Analysis, "online", https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html. Most cost components relate to capital costs, particularly module and inverter costs, meaning that the decreases apply universally.

[9] Ramasamy Vignesh, David Feldman, Jal Desai, and Robert Margolis. 2021. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-80694. https://www.nrel.gov/docs/fy22osti/80694.pdf.

[10] Future scenario modelling has been a regular part of system planning by regulated energy utilities in the UK for several years, many of which have been supported by Element Energy.

heating system at the end of its life, they would likely weigh various factors in their decision making, including the upfront cost of different available technologies (e.g. gas-fired furnace, heat pump, hybrid heat pump, etc.), the ongoing operating costs, the complexity of installation, and the suitability of each technology for the property. The bottom-up models in Future Energy Scenarios convert the value of these factors to consumers into equivalent, monetary value or utility, so they can be compared quantitatively.

The outputs of the Future Energy Scenario model are distinct from the capacity planning forecast discussed in Section D4 because they do not predict what is likely to occur in the future. Case in point, the Future Energy Scenarios model does not assign probability to any of the identified scenarios. The Future Energy Scenarios complements the Peak Demand Forecast by enabling Toronto Hydro to explore various pathways and quantify the impacts of those pathways to peak demand. This information is valuable because it allows Toronto Hydro to identify and quantify investments that would be required to reinforce the grid in different scenarios. This capability supports Toronto Hydro's least regrets planning philosophy in that it allows the utility to stress test its Peak Demand Forecast against plausible scenarios to ensure that the utility (1) does not overbuild the system and (2) does not become a barrier to particular decarbonization pathways.

2 Scenario Worlds

The scenario framework captured the range of uncertainties with four main 'scenario worlds' consisting of individual projections for the uptake or pace of various technologies or consumer behaviour. As illustrated in Figure 1 below, each scenario world represents a different energy system pathway oriented on two main axes: speed of decarbonization and level of societal change. These scenario worlds illustrate a view of future energy system changes for a given set of economic, social and policy assumptions. Three of the scenario worlds reach net zero emissions by 2050.

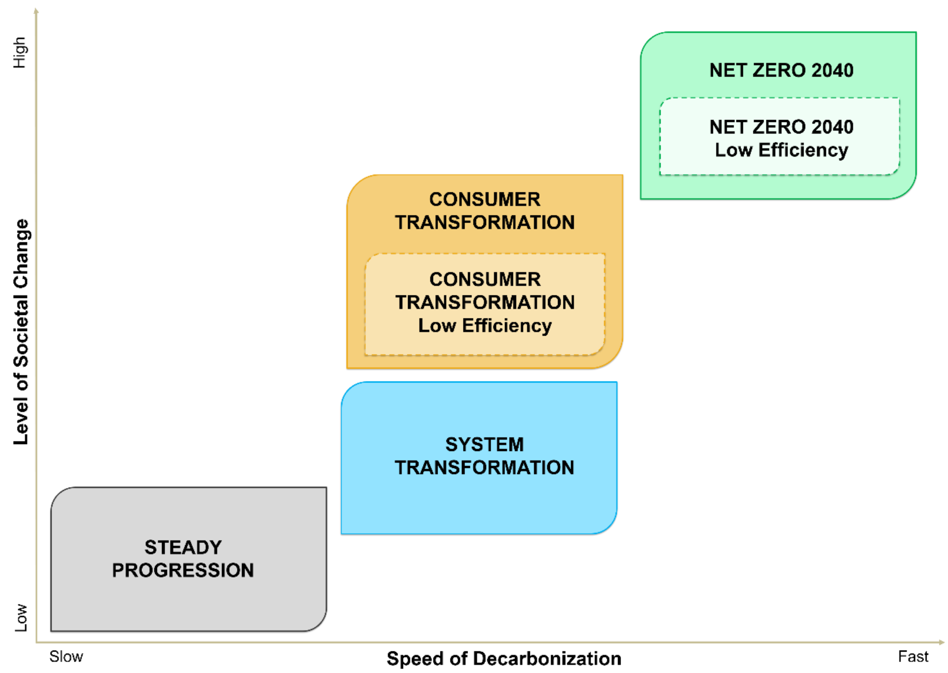

Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change

The four scenario worlds are structured as follows:

- **Steady Progression** is a low-ambitious electrification scenario that makes general progress towards decarbonization but falls short of the net zero 2050 goal. This scenario reflects minimal consumer behaviour change and is the slowest decarbonization scenario.
- **System Transformation** is a top-down scenario driven by policy-makers. It entails high levels of transportation electrification, but lower levels of heating electrification, energy efficiency and DERs.
- **Consumer Transformation** is a scenario in which consumers play a more prominent role in driving results. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. **"Low Efficiency" Consumer Transformation** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited. This sensitivity analysis provides a helpful view into the potential impact of energy efficiency on the distribution grid.

- **Net Zero 2040** is the highest ambition scenario, which is focused on meeting key policy targets early. This scenario aligns with the City of Toronto's TransformTO net zero 2040 goals, and leverages highly ambitious levels of efficiency, electrification, and DERs. **"Low Efficiency" Net Zero 2040** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited.

The low efficiency modified scenarios for Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies and strategies which are able to mitigate peak demand growth. These sensitivity analyses provide a helpful view into the potential impact of energy efficiency on the distribution grid, as well as insight into the highest levels of demand that Toronto Hydro's system could face in the journey to decarbonize by 2050.

2.1 Future Energy Scenarios Driver Projections

Each scenario world was constructed by combining uptake forecasts for a number of individual drivers of growth, generation, flexibility and efficiency. Each driver was modelled separately on a Low/Medium/High/Very High basis and then mapped to the scenario worlds. Table 1 shows the calibration of the various drivers for each scenario world. The sections that follow describe the drivers in more detail. For an in-depth explanation of each of the growth driver uptake scenarios, refer to the Future Energy Scenarios report at Exhibit 2B, Section D4, Appendix B.

Table 1: Growth, Generation, Flexibility and Efficiency Drivers within Scenario Worlds

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1.1 Core Demand

The majority of current electricity demand within Toronto can be categorized as underlying demand from domestic customers and industrial and commercial ("I&C") customers. Underlying demand refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excludes demand from new low carbon heating technologies such as electric vehicle charging or heat pumps. The latter are modelled as separate segments.

Collectively this underlying demand from these two sectors is referred to as the "core demand". Future core demand for these two sectors is primarily controlled by two key variables:

The total number of customers connected to the system – which is controlled by the size of the building stock (number of buildings); and

The energy intensity of the customers within those properties – which is assumed to be controlled by the uptake and efficiency of customer appliances.

2.1.2 Low-Carbon Transport

Future Energy Scenarios created consumer-choice uptake scenarios for electric vehicles across the following transport segments:

- Light duty battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV);
- Medium and heavy-duty electric vehicles;
- EV buses; and
- Electrified rail.

The low, medium and high scenarios were developed for each vehicle segment based on factors such as vehicle attributes (i.e. price, running cost, performance), consumer attributes (i.e. travel and charging patterns, socio-economic factors), charging infrastructure, and policy and incentives (i.e. grants, carbon tax, phase-out dates etc.).

2.1.3 Decarbonized Heating

Heating is modelled by assessing the business case for various heating technologies across the domestic and I&C building stock types. Future Energy Scenarios considered the following heating technology types in the modelling:

- Traditional fossil-fuel heating technologies (natural gas boiler, natural gas furnace, oil and LPG burners and coal burners);
- Air source heat pump;

- Ground source heat pump;
- Hybrid heat pump;
- Biomass furnace/boiler, and
- Electric heater.

Uptake and efficiency of the heating technologies is varied across the scenarios to represent the possible futures depending on costs, incentives, thermal efficiencies, technological development, and consumer behaviour.

2.1.4 Distributed Generation, Storage, and Flexibility

A broad range of distribution-level generation, storage, and flexibility technologies were considered as part of Future Energy Scenarios. Figure 2 below depicts the total set of technologies modelled. For each technology, four scenarios were developed (low, medium, high, and very high) to include the range of possible future scenarios. Based on technology suitability, system needs, supporting policies, and financial incentives, there are three dominant generation technologies for Toronto: solar PV (both rooftop and ground-mounted), non-renewable generation, and energy storage.

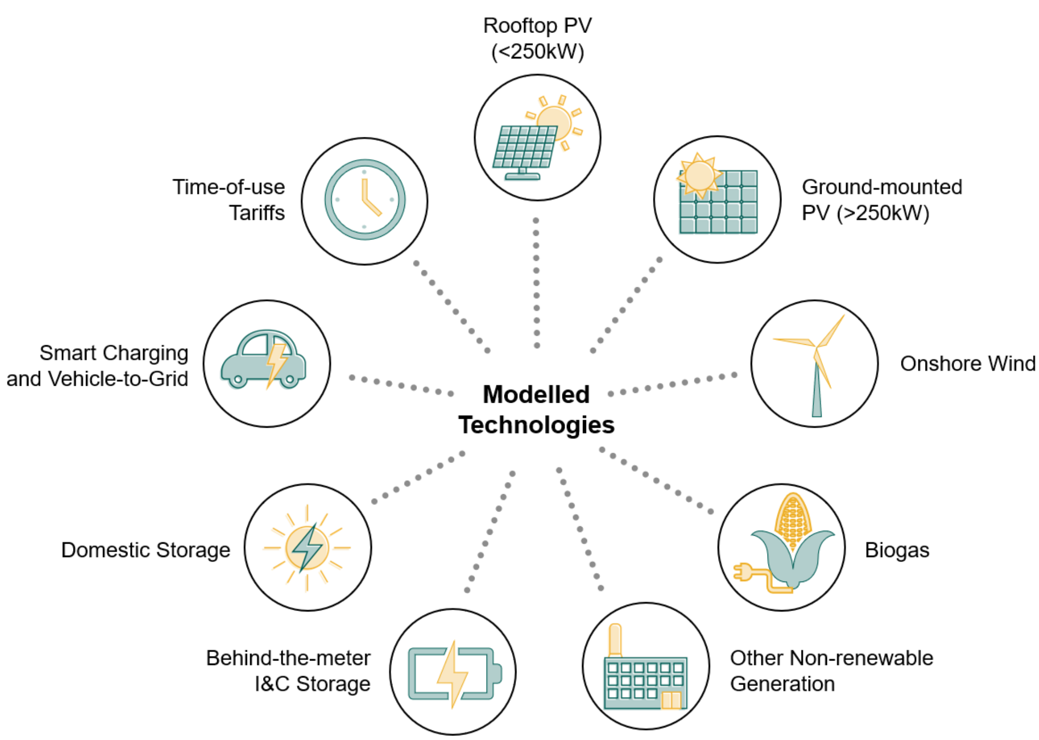

Figure 2. Distributed Generation, Storage, and Flexibility Technologies

2.2 System Impacts

The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across Toronto Hydro's distribution system.

The Future Energy Scenarios datasets were loaded into the model to create projections for the changing demand and generation on the system out to 2050. In order to provide a complete picture of the potential changes on the system, the Future Energy Scenarios model projects the annual consumption and peak electricity demand for the system's 88 terminal station bus pairs, as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in loading across the distribution system.

Figures 4 and 5 show the resulting peak system load for Toronto Hydro. The two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility, and renewable generation are realized. In the absence of these benefits being realized, the system peak loads by 2050 would be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figures 3 and 4. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management.

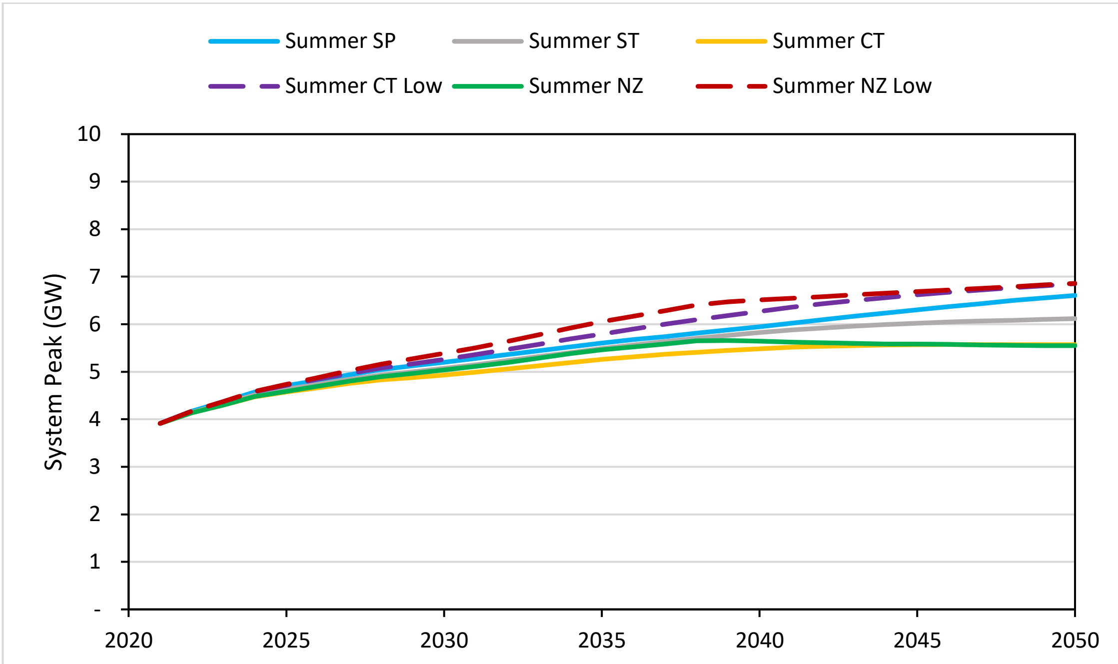

Figure 3: Summer System Peak for Scenario Worlds

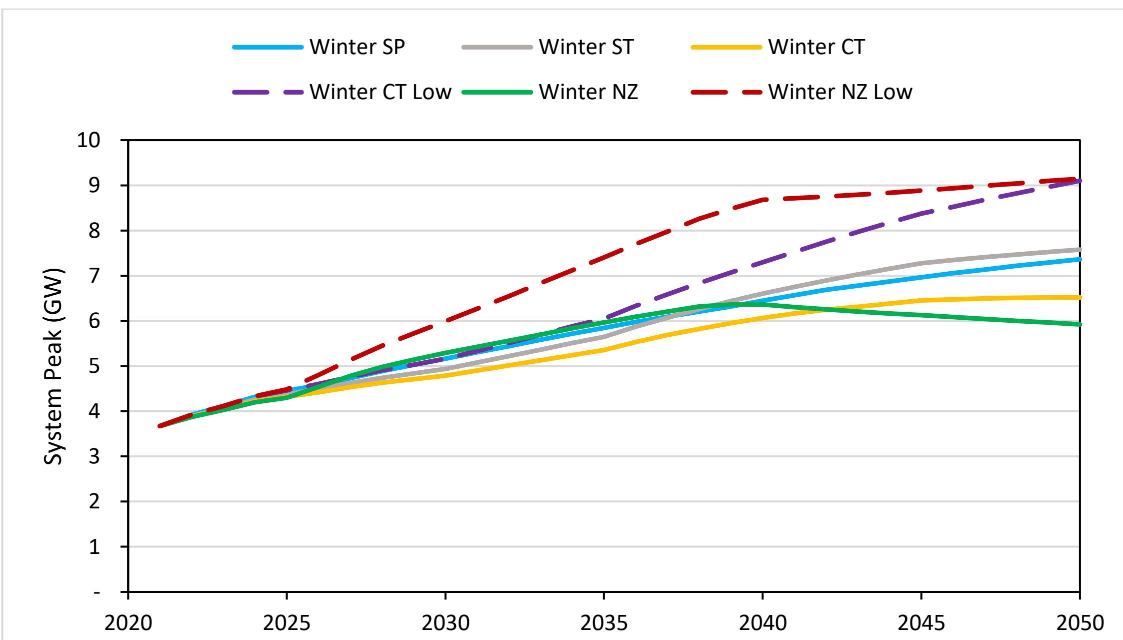

Figure 4: Winter System Peak for Scenario Worlds

3 Future Energy Scenarios – Key Takeaways

The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps.

The nature of load changes on the distribution system varies considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the what pathway of decarbonization is chosen by consumers or governments. The 2030s sees the system peak shift to winter with loads increasingly being driven by heat pump uptake and EVs. In this decade, load growth also starts to diverge across the scenario worlds, highlighting the need for early planning and capacity investments to ensure the distribution system is prepared for both near-term and long-term energy system changes.

The Future Energy Scenarios also highlight the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two "Low" scenario worlds shown in Figures 3 and 4.

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 2B
Section D4
Appendix B
ORIGINAL
(97 pages)

Future Energy Scenarios

Report for Toronto Hydro by

Element Energy, an ERM Group company

30th May 2023

Executive Summary

Introduction

The complexity of distribution system load forecasting is increasing significantly due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are affecting network management and planning. New demands emerging from the electrification of heat and transport, growing levels of distributed generation (including variable renewable generation) and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution businesses, particularly in relation to their future energy scenario planning and load projections. Through extensive previous work in this area, Element has developed a modern, state-of-the art tool known as the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in the field. The FES model has a strong track record of active use within the industry, including for the creation of various statutory outputs and reports under the scrutiny of the relevant energy regulators due to its base in robust modelling methodologies.

This report presents the Future Energy Scenarios prepared by Element Energy for Toronto Hydro and is the first of its kind for distribution companies in Canada. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. This is predicated upon a highly granular consumer choice-based analysis of future loading conditions at each individual transformer station bus, providing a strong evidence base for network planning and the evaluation of future infrastructure investments. This establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements.

The report first provides an outline of the scenario framework used for the Future Energy Scenarios and introduces the concept of ‘scenario worlds’. This is followed by an overview of the modelling methodology, focusing on the consumer choice models utilized by Element Energy. Next, the report details how these models were used to develop future uptake scenarios for each of the drivers of demand and generation considered in the FES Model. These drivers include, for example, electric vehicles (EV), energy efficiency measures and solar photovoltaic (PV) installations. Following this, the methodology for modelling the network impacts of these changes is introduced and key results are presented. Finally, the report presents the conclusions drawn from this work.

Scenario Framework

Projections were developed using Element Energy’s suite of bottom-up consumer choice and willingness-to-pay models. These were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, datasets, and policy. To capture the range of uncertainties in a coherent and meaningful way, four main ‘scenario worlds’ were developed, consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, three of which reach net zero emissions by 2050, and illustrate the best view of future energy system changes for a given set of economic, social and policy assumptions. At a high level, the four scenario worlds differ in terms of the speed of decarbonization and level of societal change they represent, as illustrated by Figure 1.

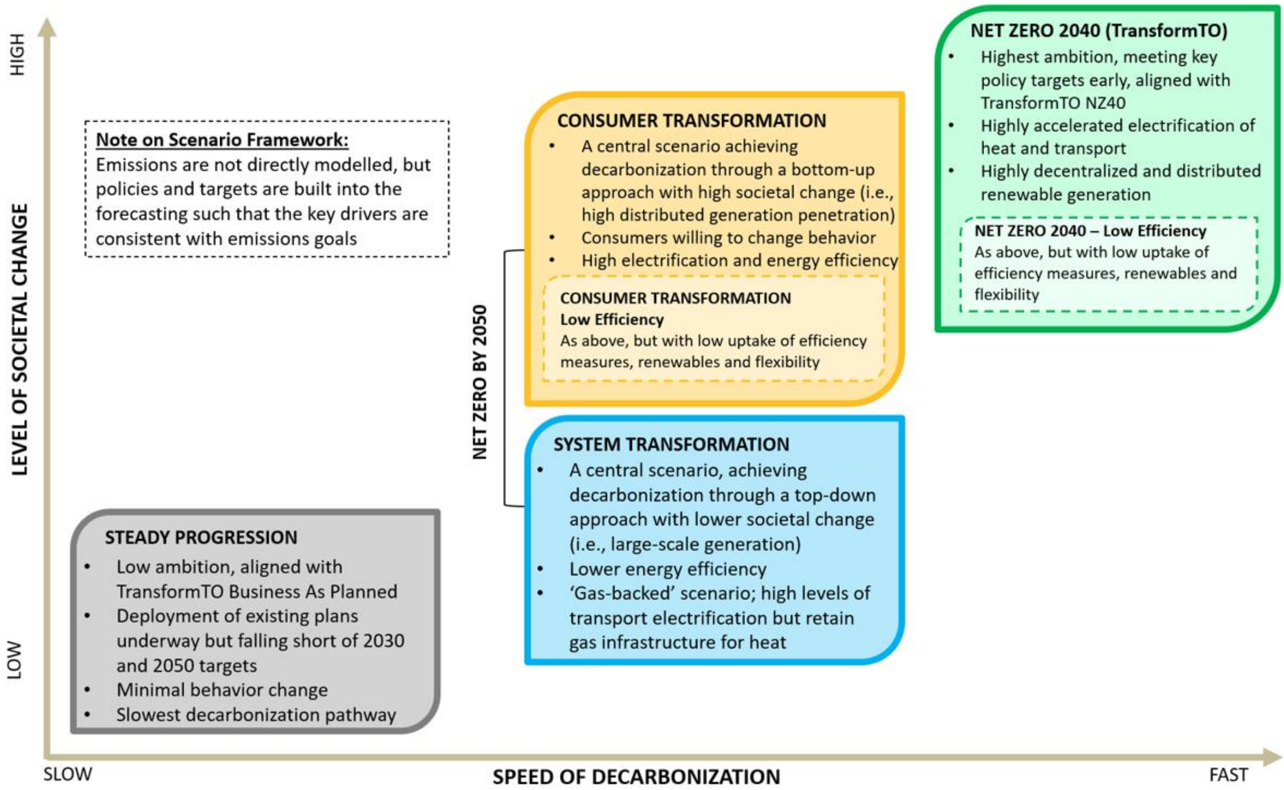

Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change.

Each of the four scenario worlds consist of a unique combination of uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. Element Energy's bottom-up consumer choice models produced three to four scenarios for every demand and generation driver, representing a range of possible futures for each technology. Based on the assumptions contained within them, these were then mapped to the overarching scenario worlds shown in Figure 1, so that each scenario world contains one scenario per technology.

The scenario worlds used in this work were developed through an assessment of existing sources that focus on the future of low carbon technologies in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios presented in this report, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four Future Energy Scenario worlds shown in Figure 1. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world which sees significant levels of electrification, behaviour change and efficiency.

[1] CER, Canada's Energy Future, 2021
[2] IESO, Annual Planning Outlook, 2022
[3] City of Toronto, TransformTO, 2021

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
   - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
   - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050.

Modelling Framework

The Future Energy Scenarios capture potential changes across a broad range of key sectors that are expected to impact upon network load. As described above, the projections were created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. In building these consumer choice models, historic deployment rates of technologies are analyzed to determine uptake levels, which are used to calibrate the model.

Where consumer choice modelling is applied within the Future Energy Scenarios, discrete choice modelling[4] is utilized. This is based on the concept that consumers try to maximise their 'utility', which is a monetized indicator representing the value of a technology to a consumer. Discrete choice models assess the perceived value to consumers of a range of competing technologies.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers into an equivalent monetary value, or 'utility', so that they can be compared quantitatively. This process is shown in Figure 2.

[4] Kenneth E. Train, Discrete Choice Methods with Simulation, 2002

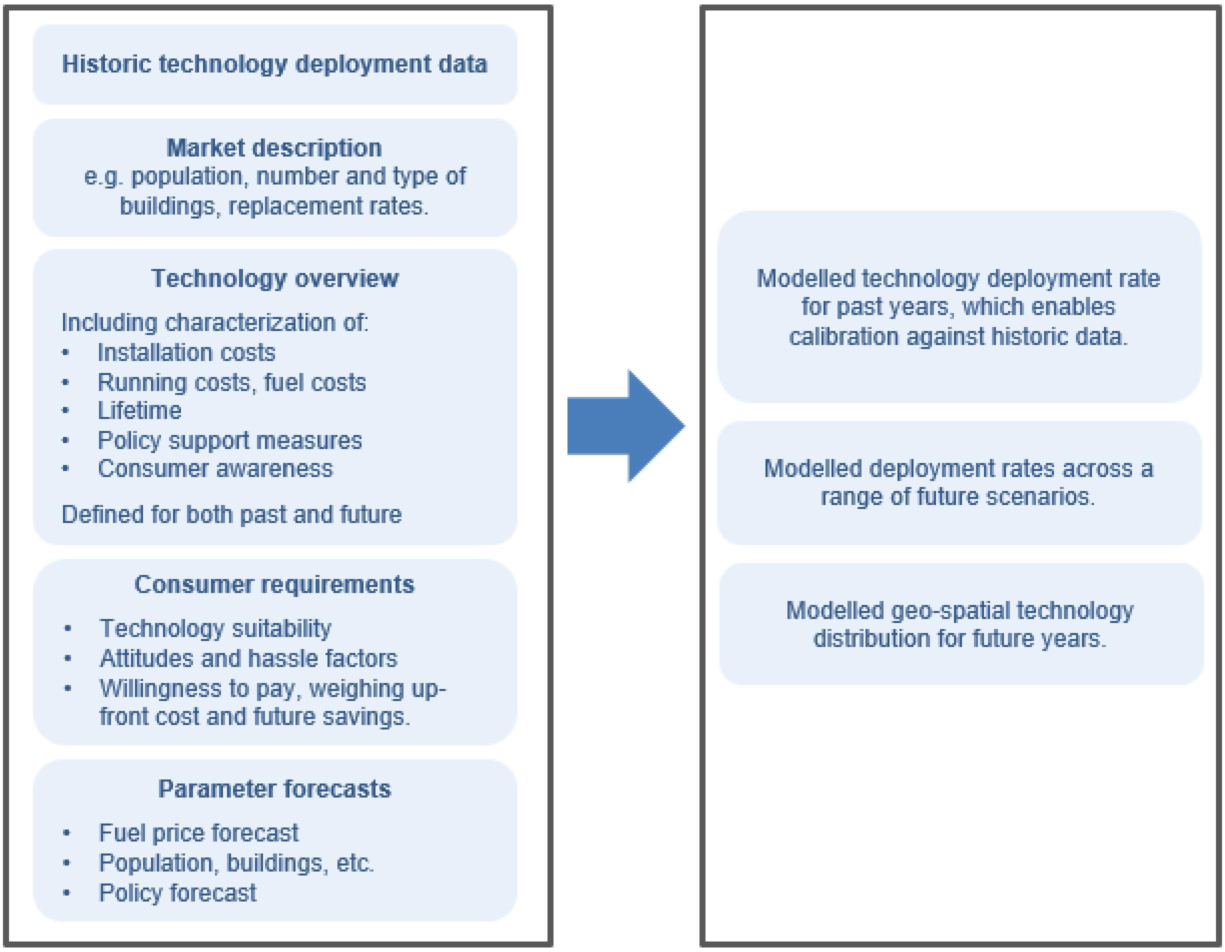

Figure 2: General approach to modelling future technology deployment.

The consumer choice models utilized in this work have been tailored to Toronto Hydro's network area to take into account specific local factors, such as policy measures (e.g. the Canada Green Homes Grant) and the breakdown of vehicle stock. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations.

Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as "core demand". At present, the majority of energy used for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to "core demand" in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in modelling future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options on future network loads under a range of scenarios.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, the peak instantaneous power demand experienced by the network generally also increases. To help reduce the amount of network reinforcement required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage as well as smart charging and vehicle-to-grid (V2G) options for electric vehicles. Energy storage is modelled as a distinct technology segment which can help to shift peak power loads by charging when demand is low and discharging when demand is high. Similarly, smart charging and V2G chargers can help to shift loads from EVs. Respectively, these act by managing when car batteries charge and enabling cars to discharge to the network at times of high demand, effectively acting as grid storage units. Without such management of charging, the demand from electric vehicles typically spikes during times of high network demand, contributing to high overall peaks at an asset and system level. Charging flexibility measures are captured within the modelling of transport demand by assuming different uptakes of smart charging and V2G in each scenario, and applying distinct load characteristics for each type of charging behavior.

The key sectors investigated in this analysis were core demand, heating, transport, generation, and energy storage via 17 unique technology segments and 72 different customer archetypes or classes. Analysis of each technology segment was carried out to a high level of geo-spatial granularity in order to assess the impact on each of the 88 individual transformer station buses selected for analysis within Toronto. Demand increases are expected to be driven primarily by the heating and transport sectors as a result of widespread electrification via the uptake of technologies such as EVs and heat pumps. Renewable generation projections in Toronto are dominated by solar PV, while energy storage is anticipated to play a role in domestic, industrial and commercial settings.

Load impacts of the demand, generation and storage sectors discussed above are aggregated to determine the total energy consumption and peak demand for each individual asset. This facilitates an assessment of when each asset may exceed its rated capacity, and by how much. This is a critical process for informing network planning and allowing Toronto Hydro to assess the costs and timescales of possible future infrastructure upgrades.

The modelling used to generate the Future Energy Scenarios for Toronto Hydro also highlights the importance of government policies in helping to achieve the relevant net zero targets in each case and further details of the illustrative policy assumptions that were utilized for each of the technology uptake projections are included in this report. The models used throughout the analysis can be updated to reflect future policy developments and market changes which will influence the uptake of low carbon technologies.

Network Impacts

The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across the Toronto Hydro distribution network.

The Future Energy Scenarios datasets were loaded into Element Energy's FES Model to create projections for the changing demand and generation on the network out to 2050. In order to provide a complete picture of the potential changes on the network, the FES model projects the annual consumption and peak electricity demand for the 88 assets on the network as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in network loading across Toronto.

The load modelling process used by the FES Model can be divided into four main calculation stages as illustrated in Figure 3: technology counts; annual consumption and generation; profile shapes and peak demand; and scaling calibration.

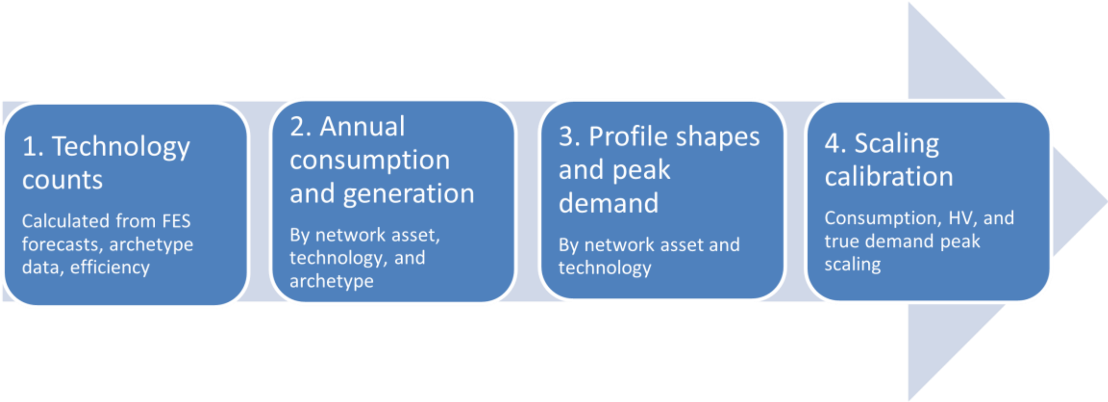

Figure 3: The main stages of the load modelling process.

Technology counts define the quantity of each technology in a given year, and their distribution across the network; in the cases of generation and storage technologies, these figures are given in terms of connected capacity rather than number of units. These figures are used, along with data regarding the characteristics of each technology, to calculate the energy consumption and generation values (MWh) each year. Peak power demand and generation (MW) is subsequently established through the application of load profiles, which describe how the energy consumption/production of each technology is distributed across the year, defined for each month at a half-hourly resolution (Figure 4). Finally, the scaling step calibrates modelled results by aligning them with real network load data for the base year provided by Toronto Hydro.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be determined by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted. Load profiles are also used in the FES model to capture the impacts of flexibility measures. For example, the FES model applies distinct load profiles for smart charging and V2G that reflect how electric vehicles are able to shift charging demand away from times of peak load.

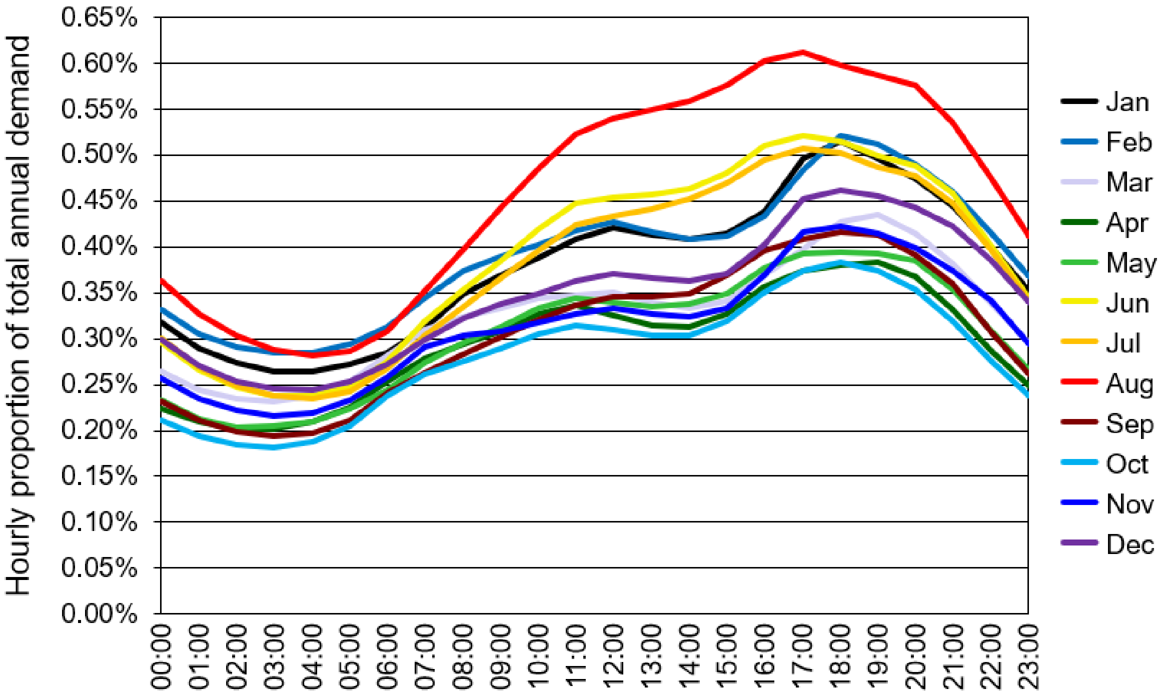

Figure 4: Example load profile: load profiles for domestic core demand.

The resulting peak network load for Toronto Hydro is shown in Figure 5, which illustrates how the two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility and renewable generation[5] are realised. If this is not the case, the network peak loads by 2050 are expected to be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figure 5. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in absolute peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management. This demonstrates the potential to avoid significant reinforcement costs and disruption throughout Toronto Hydro's network while pursuing decarbonization.

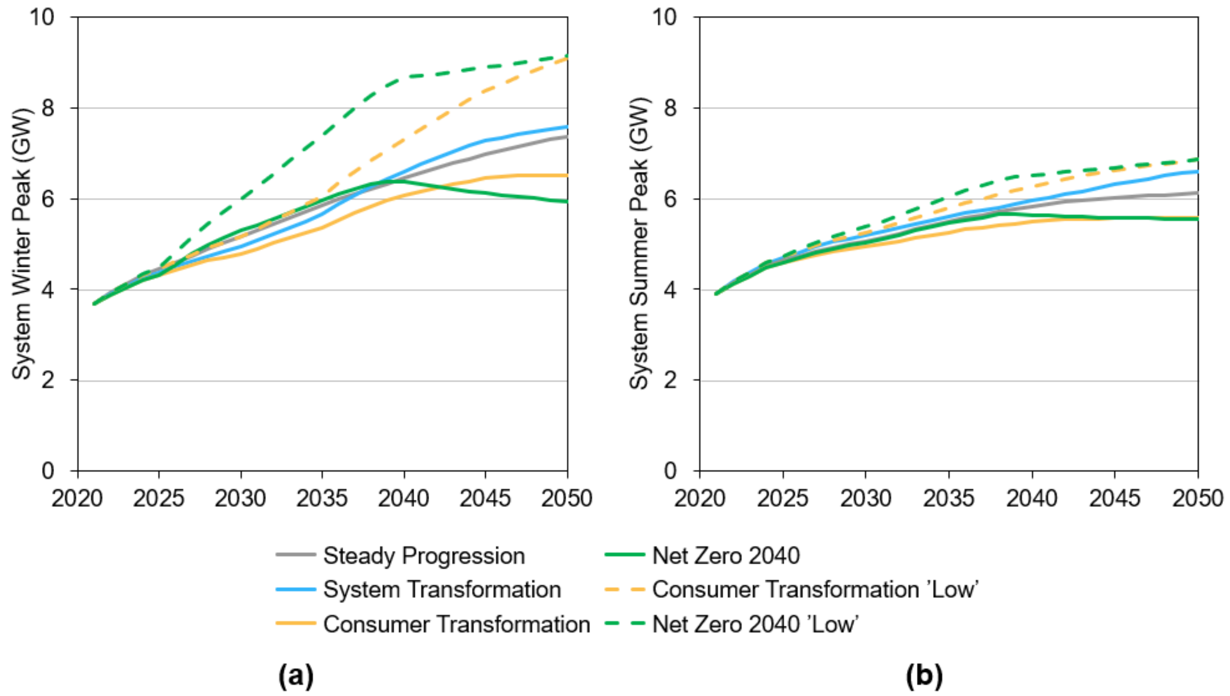

Figure 5: Network peak true demand in (a) winter and (b) summer in the four scenario worlds and two sensitivity scenarios.

In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily due to high levels of air conditioning demand which constitutes a large portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating. The 2030s see the time of network peak shifting to winter, with loads increasingly being driven by heat pump uptake and electric vehicles. As these technologies become more established, they are adopted in large numbers, especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s; however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

[5] Figure 5 shows the network-level peak *true demand* (i.e. gross), and so only the effect of behind-the-meter renewables (such as rooftop solar) would be seen in this plot. The sensitivity scenarios consider low uptake of both behind-the-meter and utility scale distributed generation.

Conclusions

This work has found that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency in every modelled scenario world. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to electric vehicles across all vehicle types. Similarly, all domestic, commercial and industrial buildings are expected to derive heat from some form of electrified technology by 2050 in all of the net zero compliant scenario worlds.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is the identification of the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two sensitivity scenario worlds shown in Figure 5. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network, showing the value of efficiency measures and demand flexibility.

Toronto Hydro’s Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance as the Future Energy Scenarios demonstrate that policy support will be essential to the attainment of a 2040 or 2050 net zero target. There are many factors that can influence this at all levels of the energy system, but the modelling shows that policy is one of the higher impact options for accelerating the pace of change.

All scenarios modelled indicate a significant increase in peak demands across the Toronto Hydro network relative to current levels, highlighting the importance of early planning and preparation for the anticipated changes this will involve for the network. Figure 5 illustrates that the extent by which peak demands will increase across the network, particularly beyond 2030, is dependent on the pathway via which net zero targets are achieved. Further, the sensitivities applied to Consumer Transformation and Net Zero 2040 demonstrate the importance of efficiency measures, renewable generation and flexible demand technologies in limiting peak demand growth. Therefore, maintaining an up-to-date understanding of the latest government policies, technological advancements, evolving supply chains and changing consumer attitudes is crucial for planning the low-carbon energy transition. Regularly updating network projections with the latest available data and learnings is important for anticipating changes in technology deployment levels and the implications this will have for network planning as we transition to a low carbon future.

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Acronyms

AC	Air conditioning
ASHP ATA	Air-source heat pump: air-to-air
ASHP ATW	Air-source heat pump: air-to-water
BAP	Business as Planned (TransformTO Scenario)
BEV	Battery electric vehicle
BNEF	Bloomberg New Energy Finance
CDM	Conservation and Demand Management
CGA	The Canadian Gas Association
ECCo	Element Energy's Electric Car Consumer Model
EV	Electric vehicle
FES	Future Energy Scenarios
GSHP	Ground-source heat pump
HV	High voltage
Hybrid ASHP	Hybrid air source heat pump
I&C	Industrial and commercial
ICI	Industrial Conservation Initiative
IESO	The Independent Electricity System Operator
LDC	Local distribution company
LPG	Liquified petroleum gas
NAICS	North American Industrial Classification System
NZ40	Net Zero by 2040 (TransformTO Scenario)
OEB	Ontario Energy Board
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RPP	Regulated Price Plan
RNG	Renewable natural gas
SUV	Sports utility vehicle
ToU	Time-of-Use
TTC	Toronto Transit Commission
V2G	Vehicle-to-grid
ZEV	Zero emissions vehicle

1 Introduction

The complexity of distribution system load forecasting is increasing significantly in Ontario and globally due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are driving changes in how these networks are managed and how capacity, investment and revenue planning is implemented. New demands emerging from the electrification of heat and transport, growing levels of distributed generation including variable renewable generation, and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

In this context, Toronto Hydro and Element Energy have developed the Future Energy Scenarios to facilitate a more detailed understanding of how these various drivers will change and interact over time. By utilizing long-term scenario-based load modelling, Toronto Hydro is able to frame the range of potential developments and understand the conditions in which each is expected to take place. The scenario-based approach to load modelling also enables Toronto Hydro to test various sensitivities around future levels of demand, generation and flexibility to increase the robustness of Toronto Hydro's planning strategies.

1.1 Toronto Hydro

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licenced by the Ontario Energy Board to serve the City of Toronto. Toronto Hydro has approximately 787,000 residential, commercial and industrial customers and distributes about 18% of the electricity consumed in Ontario.

Toronto Hydro recognizes that the energy sector is on the cusp of transformative change. In order to tackle climate change through decarbonization, electricity is expected to serve critical new roles, including fueling transportation and buildings. Toronto Hydro also recognizes that the pace and timing of these changes will be driven by a complex interplay of technological developments, consumer choice and policy. While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps, the role of low emission gas and the scale of local vs. bulk electricity supply). This reality means that system load forecasting is becoming more complex for distributors like Toronto Hydro and must manage various interlinked growth drivers in an environment of high uncertainty.

To help manage these challenges, Toronto Hydro engaged Element Energy to develop the Future Energy Scenarios model. The Future Energy Scenarios offer a range of plausible trajectories on the path toward decarbonization.

Toronto Hydro supported the development of the Future Energy Scenarios model by providing data and information to Element Energy, as requested. Toronto Hydro did not develop the Future Energy Scenarios model or underlying methodology and relied on Element Energy's experience and expertise to guide the project.

1.2 Element Energy

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution business, particularly in relation to their future energy scenario planning, projections and load modelling. We bring together a talented and dedicated team to address the problem of climate change and the transition to low carbon energy. We ensure our analysis is fully evidence based and provide grounded advice on what is required to achieve the change to zero carbon energy systems. We focus on enabling technological, social and policy solutions to the problem of climate change and planning for the impacts these solutions have on our changing energy networks.

The success of Element Energy's demand, generation, consumption, and customer load modelling tools is based on our commitment to ensuring that our high-resolution scenario load modelling tools and outputs are robust, easy to use, accurate and customized to the specific needs of each distribution business. With the changing requirements on electricity distribution networks and the impact of factors such as embedded generation, energy storage, changing customer behaviour, new technology adoption, gas substitution, tariff reform and load control, we believe it is important to provide increased visibility of the impact of these factors under various future scenarios. This has necessitated the development of a robust, consumer choice-based load modelling approach that has the capability to produce reliable projections at a level of asset and customer resolution that has not previously been available to distribution businesses. We have implemented this approach for various distribution companies and other key stakeholders in the sector over the past 15 years and we bring the value of this experience and the existing tools and datasets we have developed to our work for Toronto Hydro.

Importantly, our extensive previous work in this area means that we have a modern, state-of-the art tool, the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in this area, with a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. The FES Model is also widely used by the various electricity distribution companies we work with to assess projections from their respective market operators and other key stakeholders in the sector.

1.3 Report Structure

This report provides an overview of the Future Energy Scenarios (FES) developed for Toronto Hydro. The report is structured to first outline the scenario framework and explain how individual scenarios are brought together to create four different possible future scenario worlds. Next, the report details how future scenarios were developed for each of the drivers of demand and generation considered in the FES. These drivers include, for example, the uptake of electric vehicles, energy efficiency measures and solar photovoltaic (PV) installations, etc. Finally, the report presents the key conclusions drawn from this work. The report is structured as follows:

Section 2 outlines narratives for four different future worlds and details how the different future scenarios for each of the key drivers are combined to produce these scenario worlds.

Section 3 explains the modelling framework, the application of bottom-up consumer choice approaches to developing uptake trends, and the customization process to capture local factors in Toronto.

Section 4 describes how the different individual uptake scenarios were developed for the key drivers of demand and generation, including the modelling methodology and the geospatial disaggregation across Toronto Hydro’s operating region.

Section 5 presents the network impacts of the different scenario worlds, explaining why the trajectories follow different paths, and what this means in terms of real energy system developments.

Section 6 presents the conclusions drawn from this work.

2 Scenario Framework

The scenario framework is the method used by Element Energy to represent the range of uncertainties in the low carbon energy transition. This approach involves defining four **scenario worlds** that represent different energy system pathways, three of which reach net zero emissions by 2050. These pathways represent different positions on two main axes: speed of decarbonization and level of societal change (Figure 6Figure 6). Each of the four scenario worlds was constructed by combining uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. To capture a broad range of different possible futures, three to four scenarios were produced for each driver and subsequently mapped to the scenario worlds (Table 1Table 1).

The scenarios worlds used in this work were developed through an assessment of existing sources that focus on the future of the low carbon transition in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. Another key source was the framework used by the National Grid in the UK, which defines scenario worlds according to their level of societal change and speed of decarbonization. This framework served as a starting point for establishing, and visualizing, the difference between the scenario worlds, considering their positions on these two axes (Figure 6Figure 6).

A consumer choice-based approach was taken to modelling that aims to understand the types of customers across the network and thereby reflect the regional differences that may arise as part of the transition to a low-carbon society. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four scenario worlds. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world, which sees significant levels of electrification, behaviour change and efficiency.

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
    - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
    - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net

Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050. Figure 6 shows a description and comparison of the scenario worlds, positioned relative to each other along axes denoting the requisite societal changes and the rate of decarbonisation achieved.

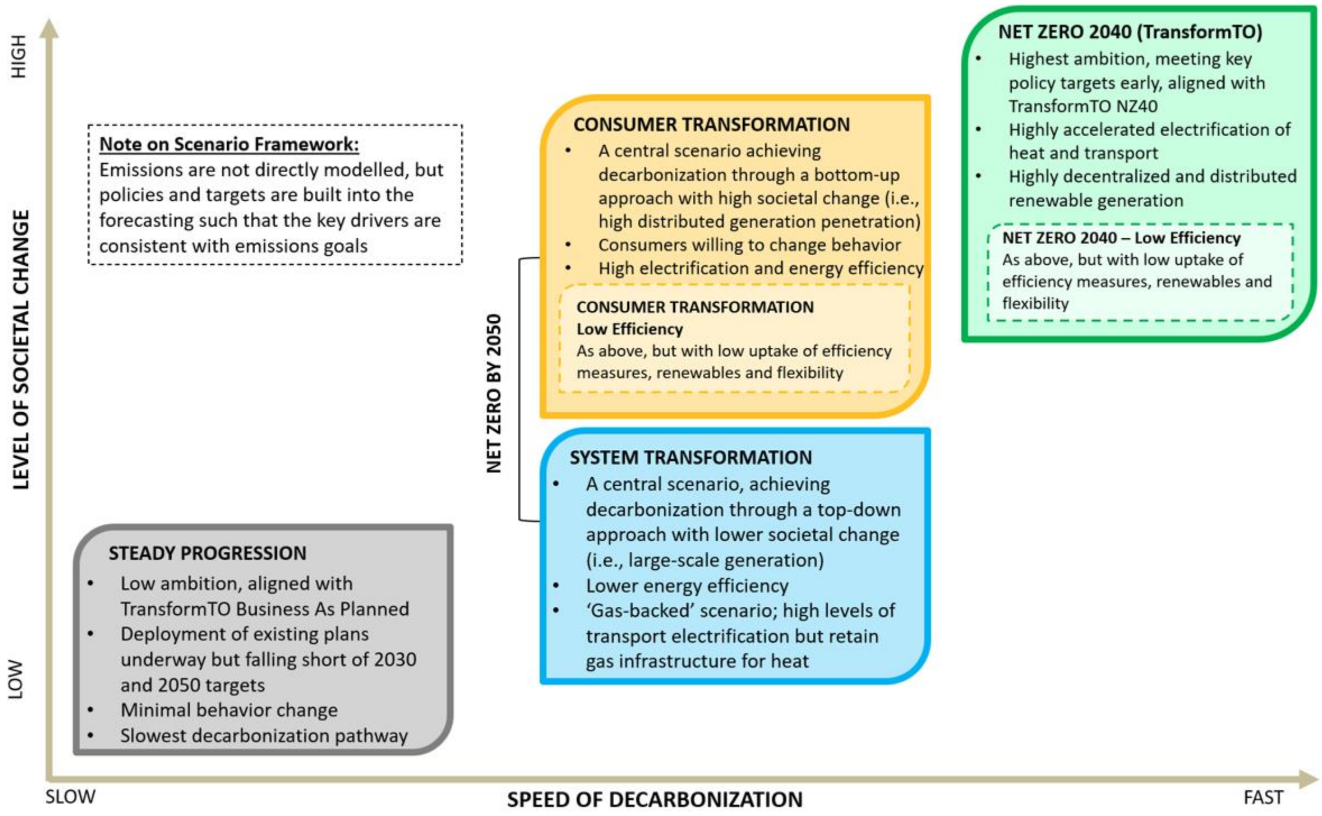


Figure 6: Scenario worlds defined on two axes: speed of decarbonization and level of societal change.

Table 1: Technology uptake scenarios that make up each of the four scenario worlds and the "Low" sensitivity cases applied to Consumer Transformation and Net Zero 2040.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1 Scenario World Overview

SP

Steady Progression

The Steady Progression scenario world is aligned with the TransformTO *Business as Planned* (BAP) scenario, in which some progress is made towards net zero targets, but most sectors fall short of full decarbonization. This sees the deployment of existing plans but does not achieve 2030 and 2050 targets. The slow pace of change is largely a result of less ambitious energy policy and a lower level of consumer behaviour change.

By 2050, heating is still largely dominated by natural gas heaters, with a limited uptake of heat pumps and electric heating. There exists little policy to incentivize low carbon heating or to remove fossil fuel options from the market. In both domestic and I&C sectors, efficiency improvements are slow and capture only a basic level of home retrofit. The transport sector sees faster advancement in the low carbon transition, but still fails to fully decarbonize. The majority of cars and light trucks are electric by 2050, however uptake is inhibited by a lack of policy change and high battery prices.

Renewable generation sees a considerable increase from current levels, mostly driven by solar PV. However, wind and biogas generation see negligible uptake and renewable capacity still falls well below the levels required to replace non-renewable generation, which is not phased out.

ST

System Transformation

System Transformation is a central scenario world that achieves decarbonization through a top-down approach, reaching net zero by 2050. This assumes lower energy efficiency, lower societal change, more large-scale generation, and retention of gas infrastructure for low carbon heating (RNG and biogas).

Heating is decarbonized primarily through electrification; however, a considerable portion of heating systems switch to hybrid heat pumps, making use of retained gas infrastructure. Electricity grid demand from heating is consequently lower, however, this is offset by relatively poor energy efficiency improvements. Heating projections were designed to align with the projections developed by the Canadian Gas Association.

Transport follows a full electrification pathway, with all vehicle types converting to electric powertrains by 2050 or before. These changes are driven by falling technology costs, an internal combustion engine vehicle ban in 2035, and a more ambitious carbon tax policy.

Distributed renewable generation capacity sees a moderate increase; however, electrification is assumed to be primarily facilitated by increases in larger transmission-connected generation. Similarly, grid flexibility sees some advancements, with vehicle-to-grid slowly replacing standard smart charging.

CT Consumer Transformation

Consumer Transformation is the second central scenario, achieving decarbonization primarily through bottom-up societal change rather than top-down system change. Shifts in consumer behaviour occur faster and earlier, with consumers increasingly prepared to engage with new smart technologies and flexibility markets. Widespread electrification is aided by high renewable generation penetration across the network, and steady improvements in energy efficiency.

Transport follows the same pathway as System Transformation, following a full electrification route that sees complete decarbonization by 2050. Similarly, the heating sector relies entirely on electrification, with ambitious policies introduced early on to incentivize heat pumps and ban fossil fuel systems. The gas grid is gradually decommissioned and, therefore, hybrid heat pumps are used only as a transition technology.

Since both heat and transport follow ambitious electrification pathways, electricity supply will need to scale up at a similar rate. Therefore, this scenario world sees a higher uptake in distributed renewable generation, driven primarily by falling technology costs. Non-renewables phase out completely by 2030, with this capacity replaced primarily by solar PV, wind, and biogas generation. Increases in generation are coupled with increases in efficiency, storage capacity and engagement in flexibility markets, facilitating a transition to a smarter energy system.

Consumer Transformation – Low Efficiency

The Low Efficiency sensitivity scenario is included to investigate the effects of coupling electrification on the scale of Consumer Transformation with low uptake of efficiency measures, flexibility and renewable generation. This will lead to higher peak loads and so provides useful insight for Toronto Hydro.

NZ2040 Net Zero 2040

Net Zero 2040 is the most ambitious scenario world and has been created to align with the TransformTO NZ2040 scenario. Key policy targets are met early, and electrification of heat and transport are accelerated such that full decarbonization is achieved by 2040. The approach taken is highly decentralized, with very high uptake in distributed generation and strong engagement from consumers. In order to develop these scenarios, it should be noted that underlying consumer choice models had to be manually tweaked to align with the required level of ambition.

Electric vehicle adoption follows a sharp uptake trajectory, driven by an evolving carbon tax policy, and an early ban on internal combustion engine vehicles in 2030. To reach full decarbonization by 2040, policy schemes to incentivize scrappage of older non-zero emissions vehicles are assumed in this scenario. Gas heating is banned in both existing and new homes by 2025, and financial incentives for low carbon heating continue until the mid-2030s, resulting in full electrification of heat by 2040.

Renewable generation scales to its highest potential within Toronto, helping to meet rapid increases in electricity demand across all sectors. Flexibility measures such as energy storage are also deployed at scale, helping to shift demand away from peak hours and reduce reinforcement requirements.

Net Zero 2040 – Low Efficiency

As described above for Consumer Transformation, a Net Zero 2040 Low Efficiency sensitivity scenario is included to investigate the effects of coupling the highest modelled electrification ambition with low uptakes of efficiency measures, flexibility and renewable generation. This will lead to the highest peak loads and so provides useful insight for Toronto Hydro.

3 Modelling Framework

3.1 Bottom-Up Consumer Choice Modelling

Element Energy has extensive experience with consumer choice modelling and has gathered a detailed understanding of which financial and non-financial parameters are relevant to describing consumer behaviour and modelled technology uptake. Element Energy has previously conducted detailed studies exploring the drivers for the uptake of various low carbon technologies, based on techniques such as willingness-to-pay analysis and consumer choice studies. The datasets from these studies have been used to determine the relative importance of the various technology attributes and uptake drivers.

Where consumer choice modelling is applied within the Future Energy Scenarios, the modelling for a given technology type generally follows the structure shown in Figure 7. This modelling approach is classified as discrete choice modelling[6]. Discrete choice models address a range of competing technologies, such as different vehicle types or heating technologies, and determine which technology is the most appealing to certain consumer types. Discrete choice modelling is based on the concept that consumers try to maximize their 'utility', which is a monetized indicator representing the value of a technology to a consumer. As technology attributes vary over time, they can be updated to follow market trends (changes in costs, subsidies, etc.). Changes in the economic evaluation of technology attributes allow for the modelling of market trends.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers is into an equivalent monetary value, or 'utility', so that they can be compared quantitatively.

[6] Kenneth E. Train, Cambridge University Press, 2002, "Discrete Choice Methods with Simulation".

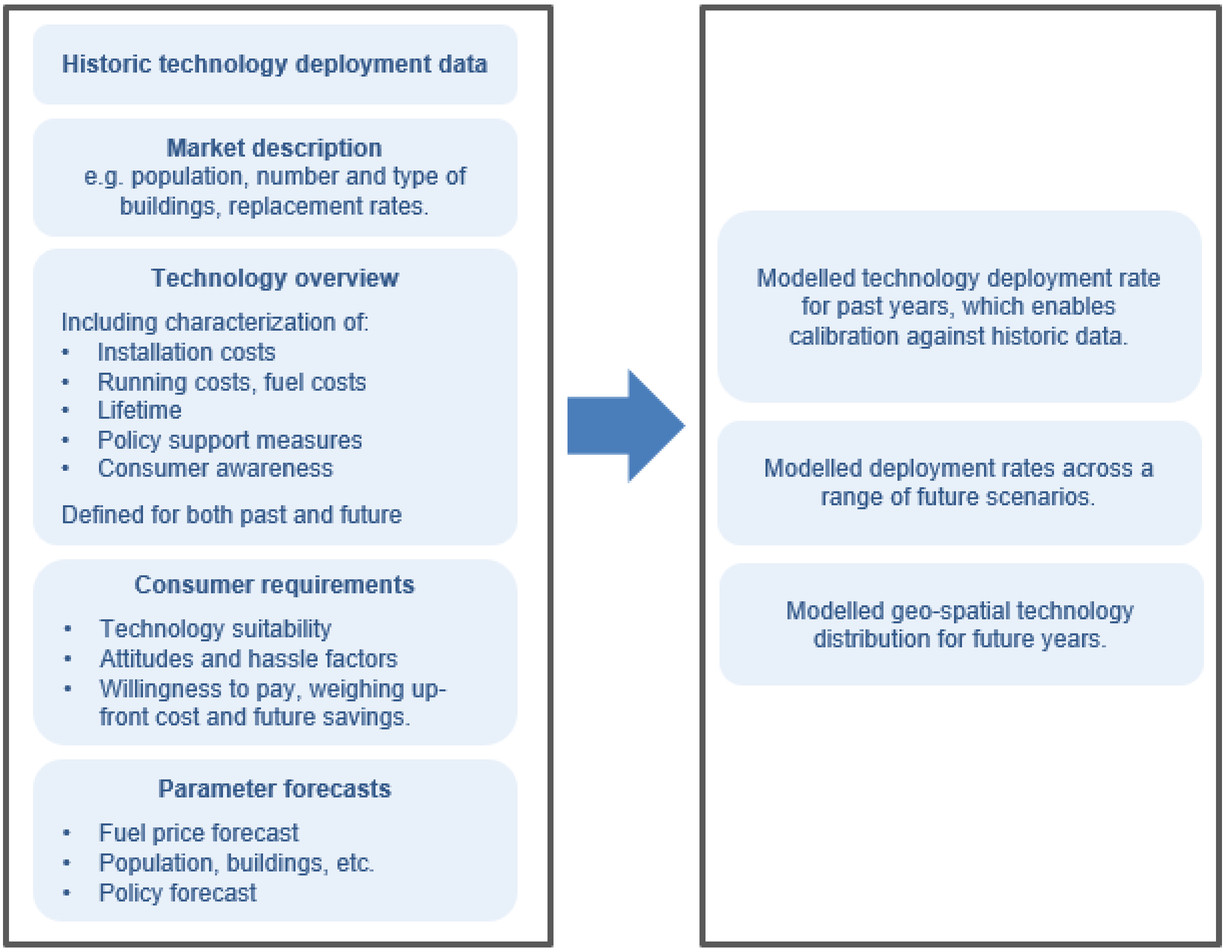


Figure 7: General approach to modelling future technology deployment.

This approach allows uptake trajectories to be based on real-world conditions (technology characteristics and costs) and actual purchasing decisions (including non-financial barriers such as charging infrastructure availability for electric vehicles or hassle barriers for heat pumps) rather than aspirational targets.

As shown in Figure 7, the first step is to gather and analyze all available datasets that describe historic deployment rates. This provides an understanding of the historic uptake levels at the most granular geospatial resolution possible. These datasets also support model calibration by enabling a correlation of how many units were deployed under historic market conditions. The subsequent modelling steps involve a variety of other parameters (such as market size, technology definition and consumer requirements), which are used to calculate a modelled purchase decision for each consumer type.

The consumer choice model evaluates the following for each year:

- The number of consumers making a purchase decision (by consumer type).
- Which technologies are purchased by consumer type, considering:
    - Financial parameters: capital cost, operational cost, taxes, fuel cost, revenues, policy incentives, etc.
    - Technology suitability and consumer awareness.
    - Hassle factors and attitudes around installation and adoption.

The modelling tools employ a tailored modelling logic to address the characteristics of the market and decision-making processes depending on the low carbon technology in question. In Section 4, the specific modelling methodologies for each technology included in this analysis are covered in more detail.

3.2 Local Factors and Customization to Toronto

Toronto Hydro's distribution area covers the city of Toronto. For planning purposes, the city is divided into 140 regions known as neighbourhoods[7], shown below in Figure 8. These neighbourhood were defined based on Statistics Canada census tracts and have a minimum population of at least 7,000 to 10,000.

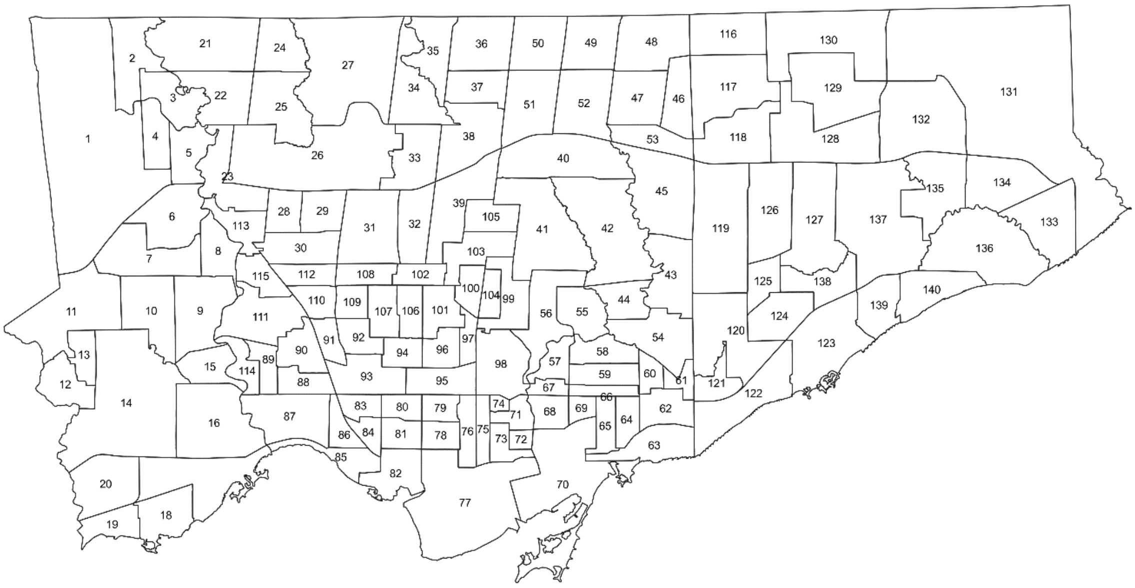


Figure 8: Toronto neighbourhoods.

Many of the drivers modelled in this work are resolved to neighbourhood level. In some cases, (e.g. electric vehicles), these are then further mapped to specific transformer station buses for the purposes of load modelling. For others, such as those based on building stock archetypes (e.g. core demand and heating technologies), modelling is performed using an archetype approach and relies on the asset-level connection counts from Toronto Hydro.

The consumer choice models utilized in this work have been adapted for Toronto Hydro to take into account specific local factors, such as policy measures (e.g. Canada Green Homes Grant) and the breakdown of vehicle stock as discussed in Section 4.3. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations, discussed in Section 4.3.6, and an assessment of the most suitable locations for onshore wind turbines, discussed in Section 4.4.3.

[7] City of Toronto, About Toronto Neighbourhoods, 2022. *Note that since the time of analysis, some neighbourhoods have been split up because of very high population growth. Effective after April 12, 2022, the number of neighbourhoods in Toronto is 158.*

4 Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as “core demand”.

At present, the majority of energy for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to “core demand” in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in projecting future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options (see Section 4.4) on future network loads under a range of scenario options.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, generally the peak instantaneous power demand experienced by the network will also increase. To help reduce the amount of network reinforcement required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage, smart charging and vehicle-to-grid options for electric vehicles, as well as time-of-use tariffs. Energy storage is modelled as a distinct technology segment which can help to shift power loads by charging at times of low grid utilization and discharging during peak hours. Similarly, smart charging and vehicle-to-grid options can help to shift loads from EVs by managing when car batteries charge and allowing them to act as electrical storage units. This is captured as a sensitivity within the modelling of transport demand by assuming different charging behaviours for electric vehicles in Toronto.

The report sections below provide further details on the assumptions, scenarios and modelling methodology used in the analysis of core demand, heating, transport, generation and flexibility, and how these are used to establish the scenario framework used for projecting loads across the Toronto Hydro network out to 2050.

4.1 Core Demand

The majority of current electricity demand within the Toronto Hydro network can be categorized as underlying demand from either domestic customers or industrial and commercial (I&C) customers. Underlying demand here refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excluding demand from new low carbon technologies such as electric vehicle charging or heat pumps. Collectively this underlying demand from domestic and I&C customers is referred to as the “core demand” on the network. Future core demand for domestic and I&C customers is primarily dictated by two key variables:

- The total number of customers connected to the network, which is assumed to be controlled by the size of the building stock; and
- The energy intensity of the customers within those properties, which is assumed to be controlled by the uptake and efficiency of customer appliances.

This concept is illustrated in Figure 9. The following section details the modelling used to characterize Toronto’s current and future core demand.

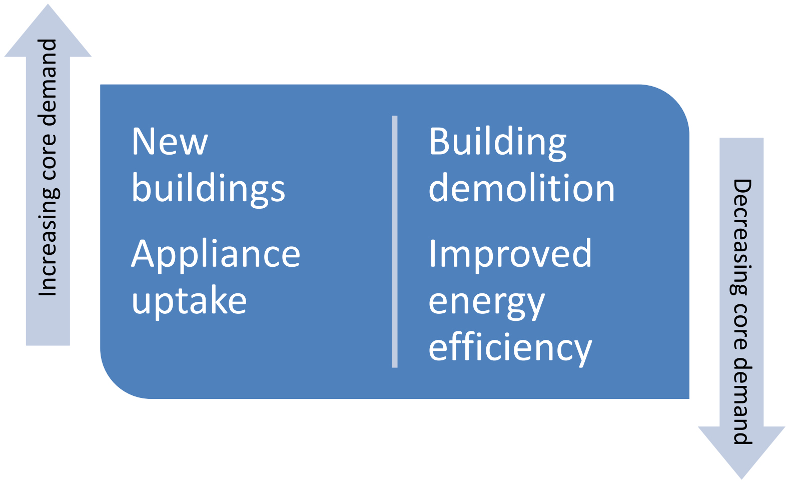


Figure 9: Illustration of core demand drivers and their effects.

The mapping of the different core demand parameters to the scenario worlds is given below in Table 2

Table 2: Domestic and I&C efficiency scenario mapping.

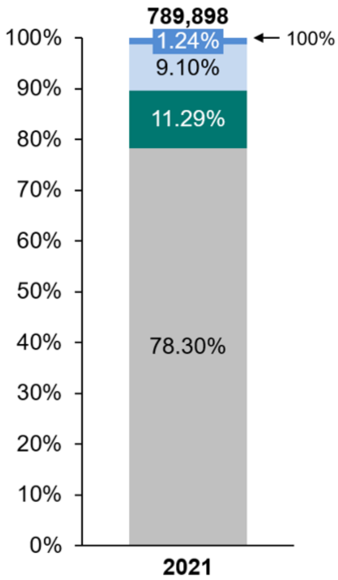
Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic Electrical Efficiency	Low	Medium	High	Low	High	Low
I&C Electrical Efficiency	Low	Medium	High	Low	High	Low
Appliance growth	Single Projection					
Domestic Building Stock Growth	Single Projection					
I&C Building Stock Growth	Single Projection					

4.1.1 Archetype Definitions

Understanding the energy usage of different building types across the modelled region is essential for accurately characterizing the core demand. Customers on the Toronto Hydro network are classified into 11 “rate classes” based on different use cases and sizes, six of which are of particular interest from the perspective of modelling domestic and industrial core demand. Table 3 summarizes the rate classes, and Figure 10 shows the breakdown of Toronto Hydro’s connections in the relevant rate classes (as denoted in Table 3). The majority of connections are residential.

Table 3: Toronto Hydro customer rate class definitions

Customer Type	Toronto Hydro Rate Class
Domestic	Residential
	Competitive Sector Multi-Unit Residential (CSMUR)
Industrial and Commercial (I&C)	General Service (GS) < 50kW
	GS 50 – 999kW
	GS 1 – 5 MW
	GS >5 MW (Large Users)
Other *(not in scope of FES analysis)*	*Street Lighting*
	Unmetered Scattered Load
	Standby Power
	microFit
	Retail Services



Rate Class	Connections	%
Customers over 5MW	54	0.01%
Customers between 1MW-5MW	494	0.06%
Customers between 50-999KW	9,768	1.24%
Customers under 50KW	71,887	9.10%
Multi-Unit Residential	89,209	11.29%
Residential	618,486	78.30%

Figure 10: Breakdown of relevant rate classes across the Toronto Hydro network.

Much of the analysis relating to core demand and low carbon technology uptake is contingent upon the use of building archetypes, also called classes, which build upon the connection data (split by the rate classes shown in Table 3) provided by Toronto Hydro. Archetypes allow the energy usage characteristics of a wide array of users to be considered in the analysis, providing high levels of regional variation while also supporting analytical efficiency. The building stock within Toronto Hydro’s region has been split into 32 domestic and 40 non-domestic archetypes, each defined by a set of relevant characteristics. The process and resulting distribution are explained in more detail below.

Domestic Archetypes

The 2016 Census of Population[8] provides household statistics at neighbourhood resolution. This dataset was used to segment the domestic building stock into groups of four different structural types (single detached houses, double or row houses, low-rise apartments, and high-rise apartments) and four age categories (pre-1960, 1960-1980, 1980-2010, post-2010). The Census data contains records of more domestic properties than there are connections within Toronto Hydro's residential and multi-unit residential rate class data. This is because there are some residential properties, such as apartment blocks, which in some cases connect to the network as bulk-metered General Service connections within Toronto Hydro's rate classes. The bulk-metered residential properties are allocated to I&C archetypes in this analysis, while the number of buildings within the domestic archetypes matches the total number of residential and multi-unit residential rate class connections.

Figure 11 shows the distribution of residential and multi-unit residential rate class connections (i.e. domestic connections) across the Toronto neighbourhoods, per Toronto Hydro's rate class data[9].

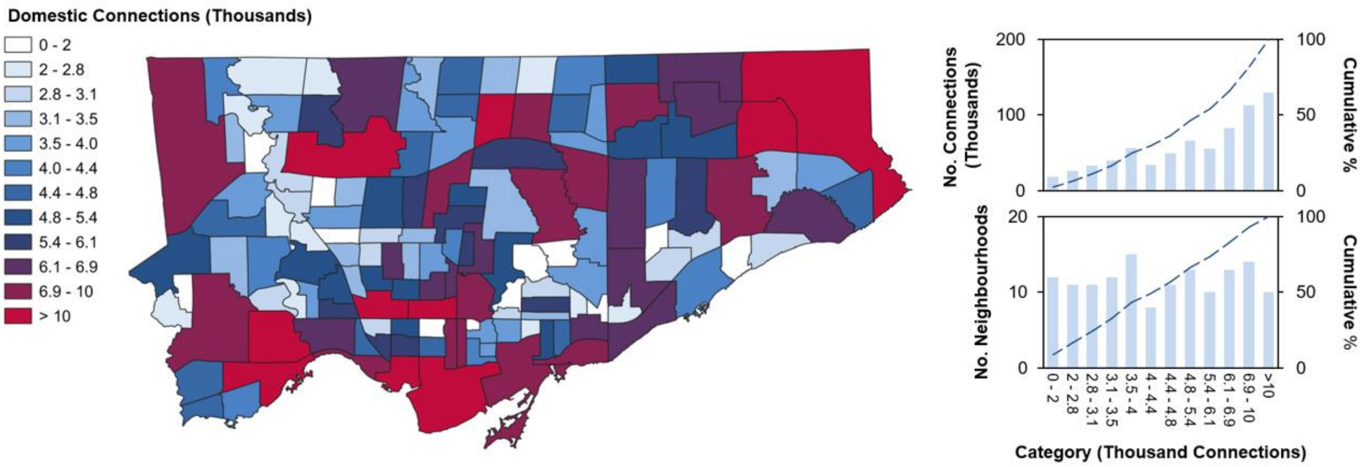


Figure 11: Distribution of domestic connections across Toronto neighbourhoods[9].

The distribution of dwelling types across neighbourhoods varies considerably, with more densely populated regions of the city having a higher proportion of apartment style homes utilizing multi-unit residential connections. This distribution of dwelling types (see Figure 12) has a significant impact on the uptake of various demand technologies seen in the scenarios.

[8] Statistics Canada, The Census of Population – Neighbourhood Profiles, 2016
[9] Toronto Hydro, Rate Class connection statistics, 2022

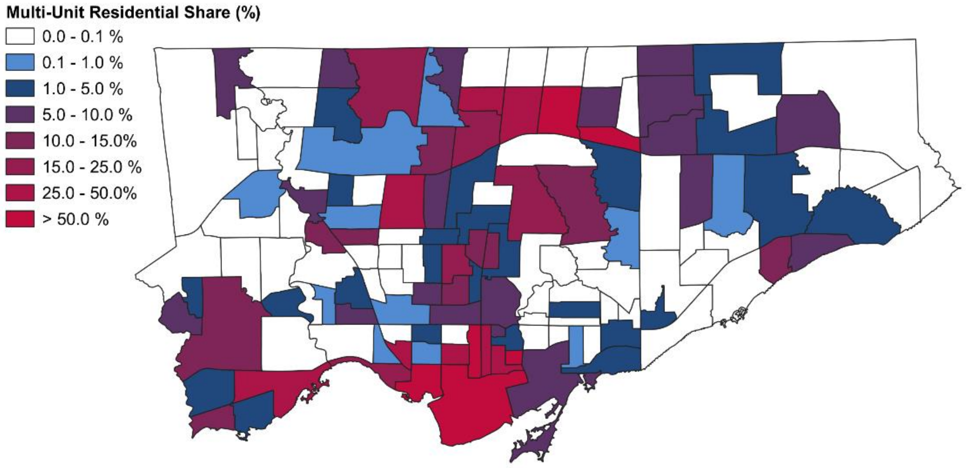


Figure 12: Share of multi-unit residential connections within Toronto Hydro's domestic rate classes.

The Toronto Hydro rate class data does not contain any additional information on the types of buildings present within the stock. Using neighbourhood and ward-level census data[8], as well as data from TransformTO[3] and The Survey of Household Energy Use[10], the connection counts were subdivided according to several parameters as follows (it is assumed that the distribution of building descriptors among the census households is retained in the Toronto Hydro rate class dataset for the purposes of subsequent calculations).

The parameters used to subdivide the stock into archetypes are heating fuel type (gas, electric, other), building age and the structural types listed above. These parameters were selected for the segmentation as buildings of similar structural type and age have similar energy usage characteristics. These factors also provide a reasonable indicator for which low-carbon heat source a building may be suited.

Archetypes are not expected to have the same share of heating fuel types – for example the proportion of homes currently using electric heating is higher within apartments than detached houses. Data from the Survey of Household Energy Use was used to determine the prevalence of existing heating fuels within each housing type.

It was found that the majority (>90%) of the building stock in Toronto currently uses natural gas as a heating fuel. Gas fuelled archetypes were subdivided into the four structural categories given above, while archetypes fueled by other means required less granularity (owing to their small share of the overall stock) and were hence categorized as houses or apartments. The breakdown of the archetypes' characteristics is illustrated in Figure 13. This leads to 32 domestic archetypes in total, consisting of 16 gas heating archetypes, 8 electric heating ones and 8 other heating archetypes as follows:

- **Gas heating**: 1 [Fuel Type] x 4 [Building types] x 4 [Age Categories] = 16 archetypes
- **Electric heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes
- **Other heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes

[10] Natural Resources Canada, Survey of Household Energy Use Data Tables, 2015

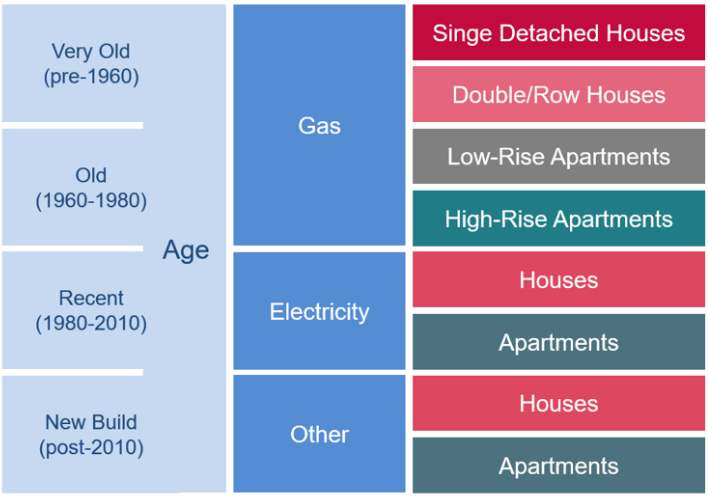


Figure 13: Breakdown of defining characteristics for domestic archetypes.

The distribution of archetypes within the Toronto Hydro rate classes is shown below in Figure 14[11].

The homogeneity of domestic multi-unit residential connections as high-rise apartment blocks is shown in Figure 14a, explaining the prevalence of this rate class in the City's urban centres in Figure 12. There is a relatively even split of building ages in Figure 14b, and the high proportion of gas heating discussed above can be seen clearly in Figure 14c.

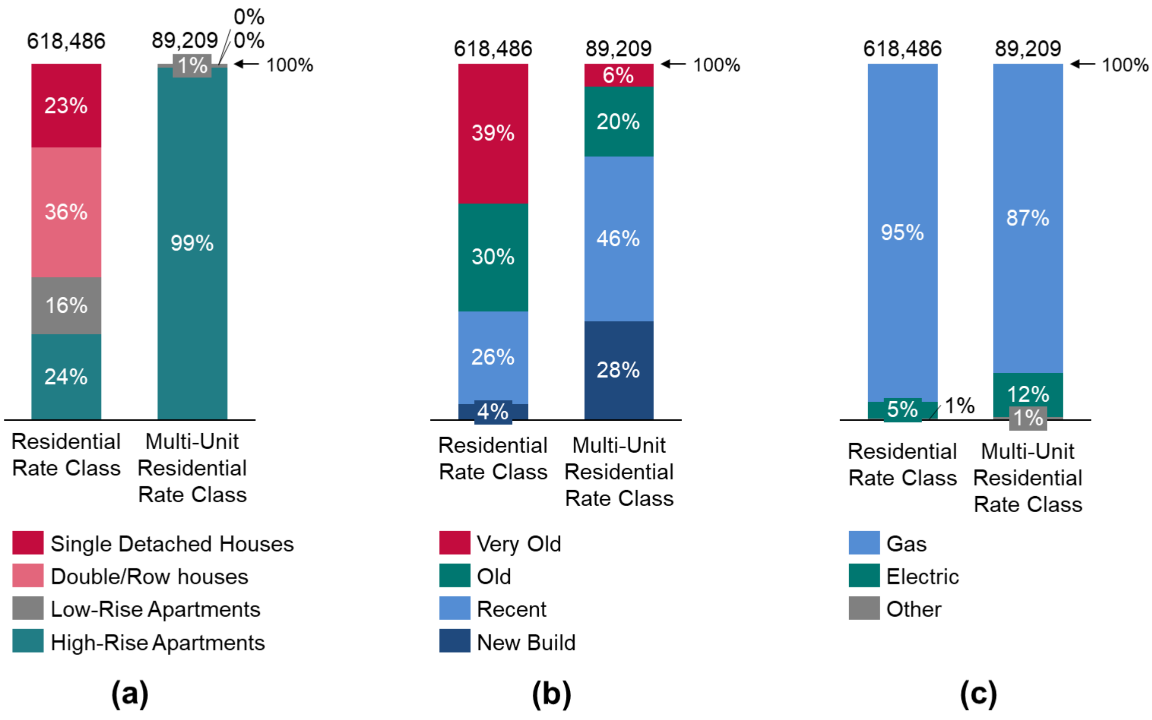


Figure 14: Distribution of Toronto Hydro's domestic building stock by (a) structural type; (b) age; and (c) current heating fuel (2021).

[11] There are a number of domestic properties which, owing to their metering arrangements and the handling of rate classes within the modelling, are categorized within I&C Multi-Unit Residential archetypes, and these are not accounted for in Figure 14.

Industrial and Commercial Archetypes

Figure 15 shows the distribution of employees across the city, in line with City of Toronto employment figures for 2020. The data shows that the majority of neighbourhoods contain relatively few employees, while most employees work in a few specific neighbourhoods. 70% of the neighbourhoods are home to fewer than 10,000 employees each, while 30% of the city's workforce is contained within just six (of 140) neighbourhoods (see inset graphs in Figure 15). There are two main centres of employment in the city: one in the city centre (bottom centre of the map) and one in Etobicoke North (top left of the map).

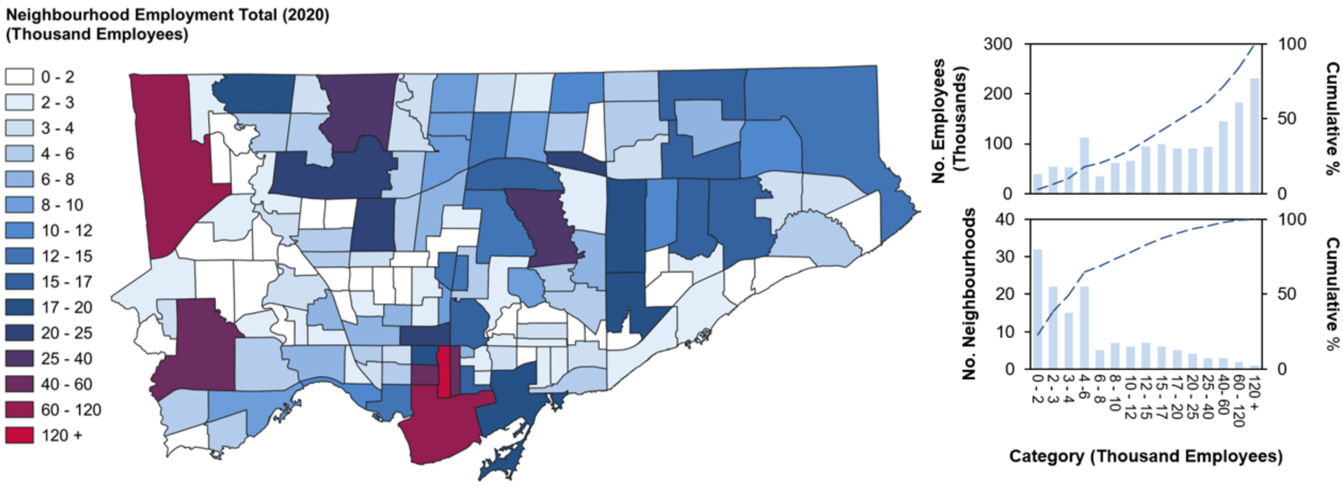


Figure 15: 2020 Distribution of Employees in Toronto[12].

The data also showed the number of establishments (i.e. workplaces) per neighbourhood per NAICS[13] sector which, when combined with the employee counts in Figure 15, can give an indication of the size of I&C buildings in different regions of the city. This dataset is shown below in Figure 16, presented as employees per establishment.

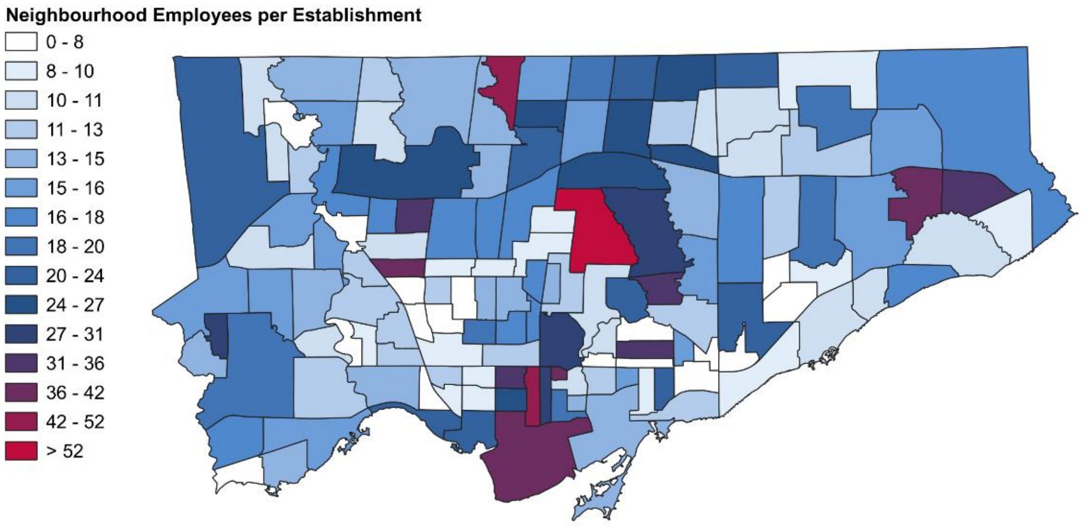


Figure 16: Employees per Establishment, 2020[12].

The dataset shown in Figure 15 is important because the derivation of the I&C building stock growth trend, as described in Section 4.1.2, is based upon employment projections. The growth in employment is assumed to

[12] City of Toronto, Toronto Employment Survey, 2020
[13] North American Industrial Classification System [NAICS & SIC Identification Tools | NAICS Association]

be in proportion to the growth in buildings in each neighbourhood, and therefore the employee density shown in Figure 16 is also implicitly retained in that analysis.

The sectoral split of employees and establishments in Toronto referenced above is shown below in Figure 17. Note that the full list of 21 NAICS sectors was condensed into seven simplified sectors for the purposes of this analysis.

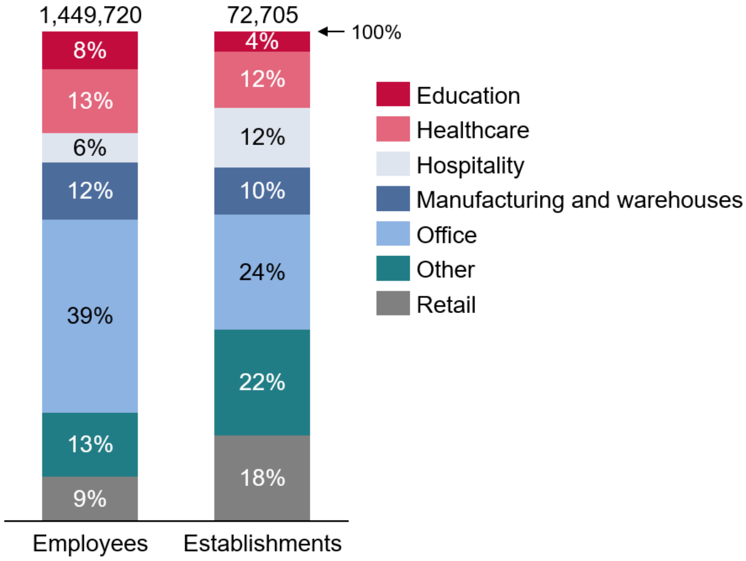


Figure 17: Simplified sectoral split of employees and establishments in 2020[12].

The seven simplified NAICS sectors described above formed the basis of the archetypes developed for this analysis. In addition to these seven, some multi-unit residential buildings are categorized as I&C connections in this analysis because they connect to the network via bulk-metered General Service connections, rather than individually metered multi-unit residential connections (see Table 3). Other characteristics considered were the fuel type (split into gas, electricity and other), and age (split by existing and new build). Note that it has been assumed for simplicity that all new builds in all scenarios will be fuelled either by gas or electricity. The breakdown of the archetypes' characteristics is illustrated in Figure 18. This leads to 24 existing and 16 new build archetypes as follows:

- **Existing:** 1 [Age Category] x 3 [Fuel Types] x 8 [Sectors] = 24 archetypes
- **New Build:** 1 [Age Category] x 2 [Fuel Types] x 8 [Sectors] = 16 archetypes

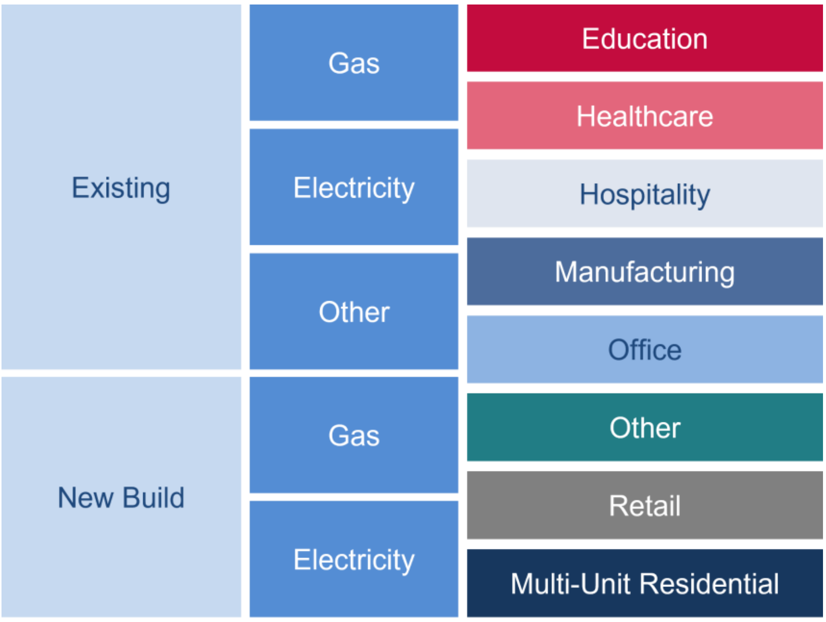


Figure 18: Breakdown of defining characteristics for the I&C archetypes.

Note that the archetypes are not characterized by rate class – customer counts for each non-domestic archetype were produced for all four I&C rate classes (see Table 3). To achieve this, a mapping between rate classes and NAICS sectors was produced (i.e. defining which NAICS sectors would be expected to contain which rate classes). The number of NAICS establishments present within the data differed slightly in each neighbourhood to the number of connections reported by Toronto Hydro. As such, the proportions of each sector were retained from the NAICS data but the overall total number of connections within each rate class was assigned according to the data provided by Toronto Hydro.

The resulting distribution of archetypes then formed the starting point for the analysis of I&C core demand and building stock growth in Toronto.

4.1.2 Building Stock

The number of buildings connected to the distribution network has been modelled as the net result of two competing factors – demolition of the existing stock and the rate of new build completions in each sector. As with the building archetyping, the building stock trends are split into domestic housing and I&C establishments.

Domestic Building Stock

Neighbourhood level net domestic growth projections (to 2041), based on the City of Toronto 2013 provincial growth plan were used for this analysis. The scenario referred to as the 2012 neighbourhood growth plan ("GP2012 NH"), has been used to model domestic stock growth. The data was extrapolated from 2041 to 2050 and mapped to the domestic housing archetypes discussed in Section 4.1.1.

Archetype specific (i.e. house and apartment) growth rates consistent with those contained in GP2012 NH were then applied to Toronto Hydro's domestic connection counts, using the distribution of dwelling types from the domestic archetypes. As such, the overall modelled growth differs slightly from the GP2012 NH trend, because the distribution of homes (and consequently the growth of the stock) in that dataset differs from that in the modelling presented in this report.

A 2008 study by Watson and Associates[14] on behalf of the City of Toronto contains historical data and projections around the ratio of demolitions to new builds across different housing types. The demolition rate derived from the report is applied to the net growth seen in each neighbourhood to find the total number of demolitions across the city (and implicitly the gross number of new builds). Figure 19 summarizes how the data described above were combined to produce a stock growth projection.

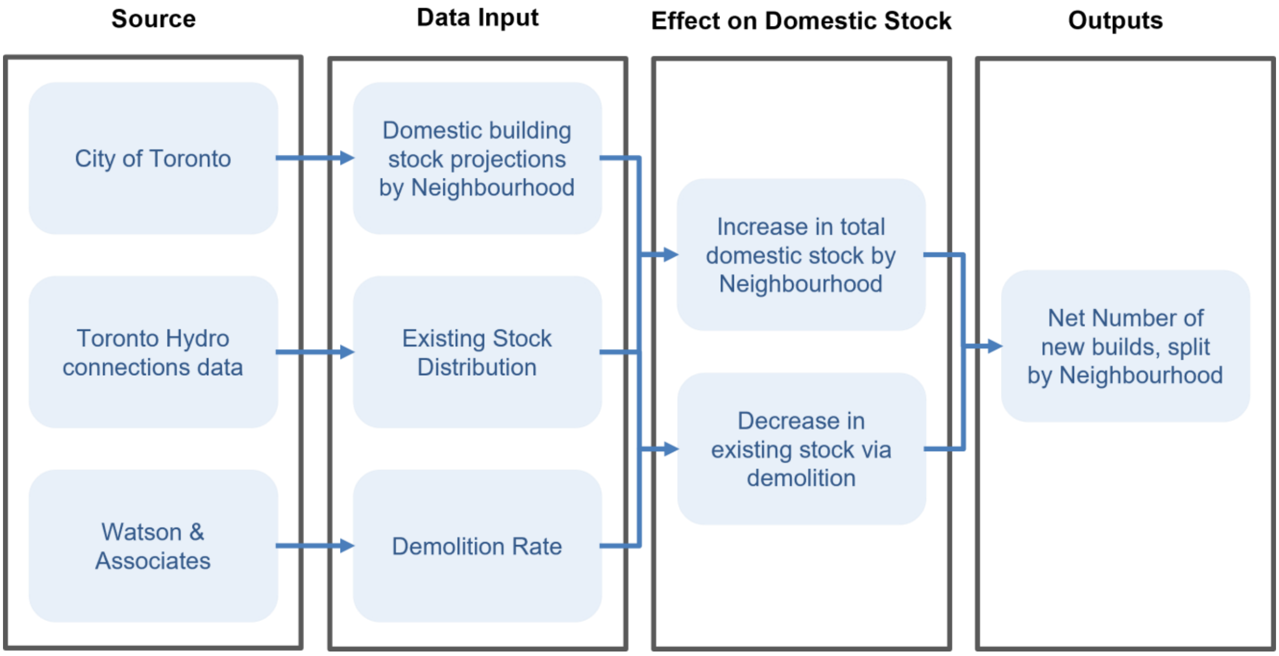


Figure 19: Method for developing domestic building stock growth projection.

Figure 20 shows the modelled net housing stock growth derived from the data sources described above. Growth (consistent with GP 2012NH) is applied to new builds only, while demolition is applied to existing stock only. The majority of growth is concentrated in apartments, which is also consistent with the neighbourhood growth plan.

[14] Watson & Associates, City of Toronto Development Charge Background Study, 2008

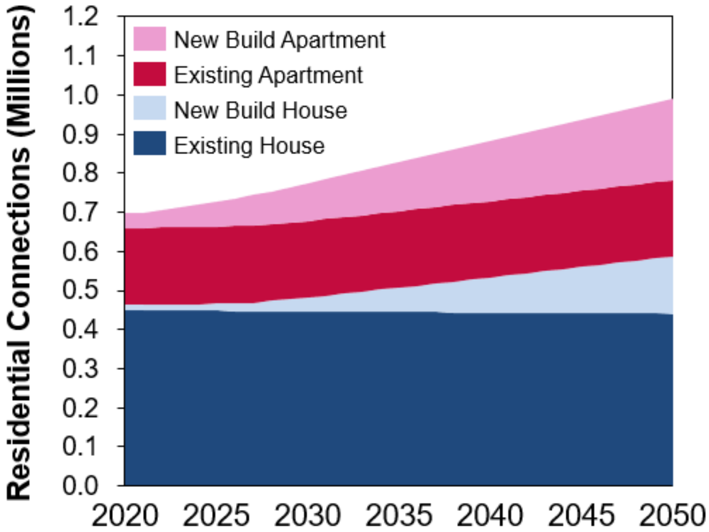


Figure 20: Modelled residential stock growth, split by dwelling type and age, rebased to Toronto Hydro connection counts in 2021.

Figure 21 shows a comparison of the overall modelled growth rate relative to that of the GP2012 NH data, TransformTO and the Canadian Ministry of Finance's population projection, showing a general alignment between the modelled approach and that of the data available in literature.

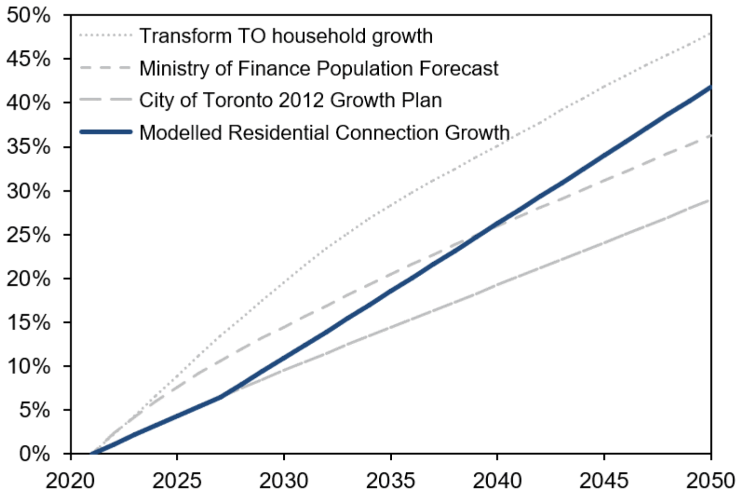


Figure 21: Comparison of modelled growth with different Toronto housing and population projections.

Figure 22 shows the modelled distribution of domestic buildings across the city in the base year and 2050. The differing building stock growth rates in action across different neighbourhoods can be seen by comparing the 2021 and 2050 distributions.

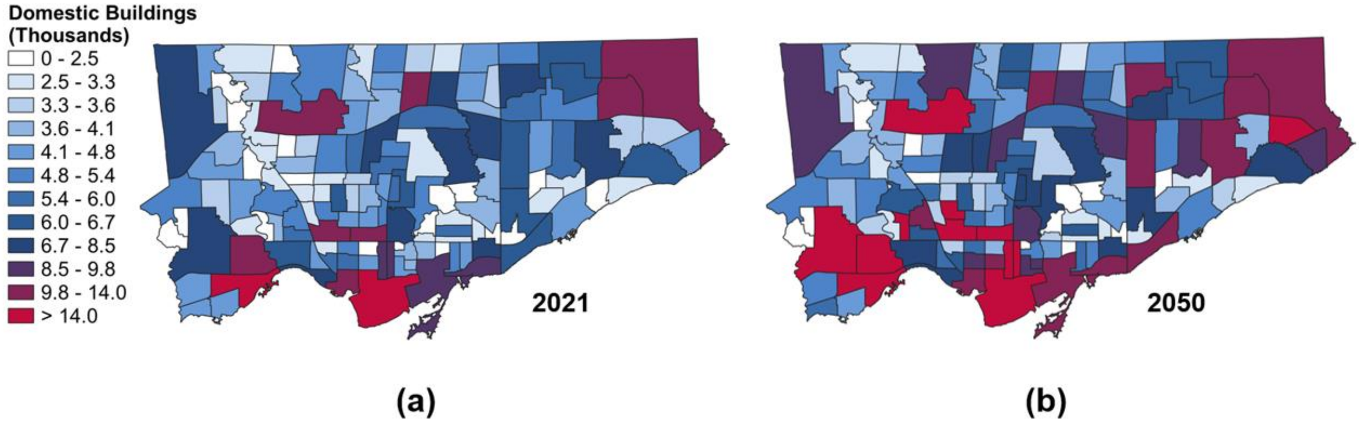


Figure 22: Maps of domestic building stock in (a) 2021 and (b) 2050.

Industrial and Commercial Building Stock

The analysis for I&C building stock was also based upon multiple data sources. The high-level process is displayed below in Figure 23.

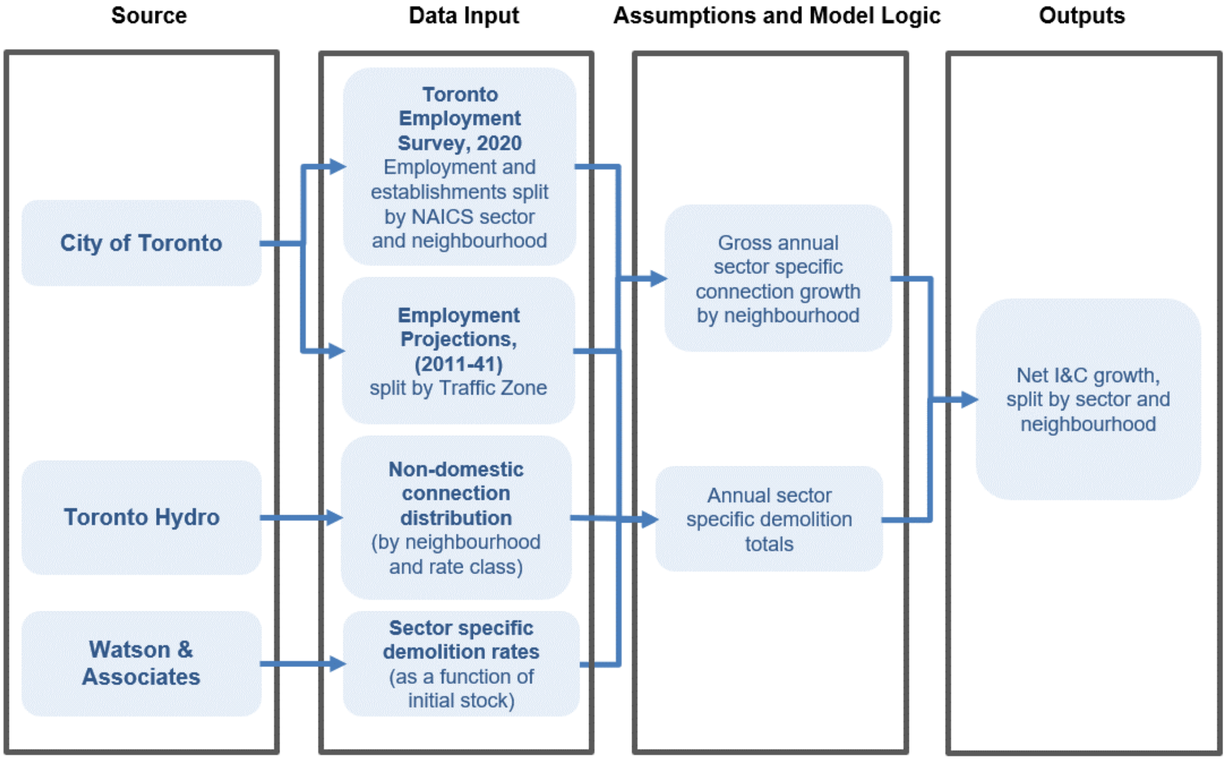


Figure 23: Method for developing the industrial and commercial building stock growth projection.

Alongside the employment statistics discussed in Section 4.1.1, City of Toronto industry employment projections from 2011 to 2041, split by Traffic Zones, were used in the I&C building stock growth analysis[15]. These projections contained five scenarios, combining different rates of economic growth and the projected impacts of the SmartTrack rail system[16]. These are summarized in Table 4 and Figure 24. Scenario 1 (medium growth, no SmartTrack) has been used as the basis for the FES analysis.

Table 4: Synopsis of City of Toronto employment projection scenarios.

Scenario	Growth	SmartTrack
Scenario 1	**Medium**	**False**
Scenario 2	Medium	True
Scenario 3	Low	False
Scenario 4	Low	True
Scenario 5	High	True

[15] Toronto Data Management Group, Traffic Zones Boundary Files, 2006 (Toronto Hydro's network area covers 677 traffic zones).
[16] City of Toronto, SmartTrack Stations Program, 2021

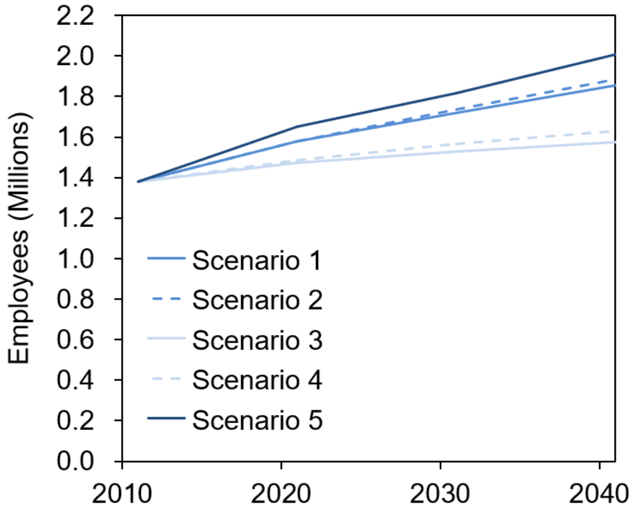


Figure 24: City of Toronto employment projection scenarios, 2011-2041.

The growth rate given by the medium growth employment projection described above has been used as a proxy for net I&C stock growth. The neighbourhood level NAICS sector split from the 2020 Employment Projection conducted by the City of Toronto was used to disaggregate the growth into neighbourhood regions. This was then rebased, using the neighbourhood distribution of the I&C archetypes discussed in Section 4.1.1.

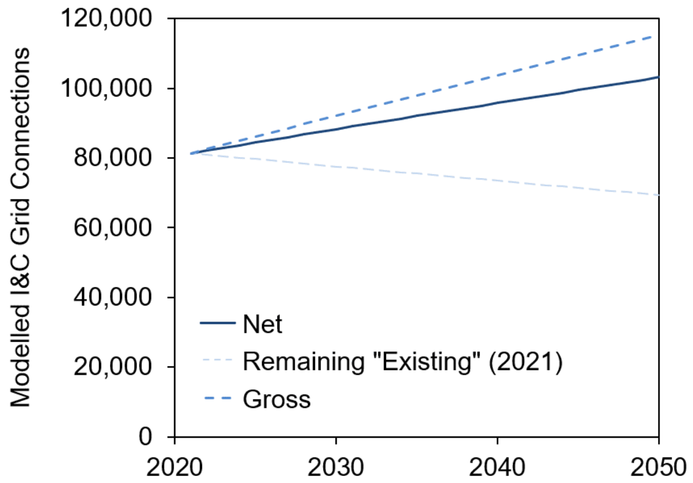


Figure 25: Modelled total I&C building stock projection.

Figure 26 shows the distribution of I&C buildings across Toronto in the base year and 2050. Unlike the domestic stock growth (shown in Figure 22), I&C building stock remains distributed around the city in a manner similar to the present day, with most growth occurring in regions which already have a high concentration of commercial buildings. High voltage I&C connections (defined as those in rate classes Customers between 1MW-5MW and Customers over 5MW) are excluded from this analysis. The growth in demand from these customers is modelled based on Toronto Hydro's assessment of the connections expected to come online in the near future.

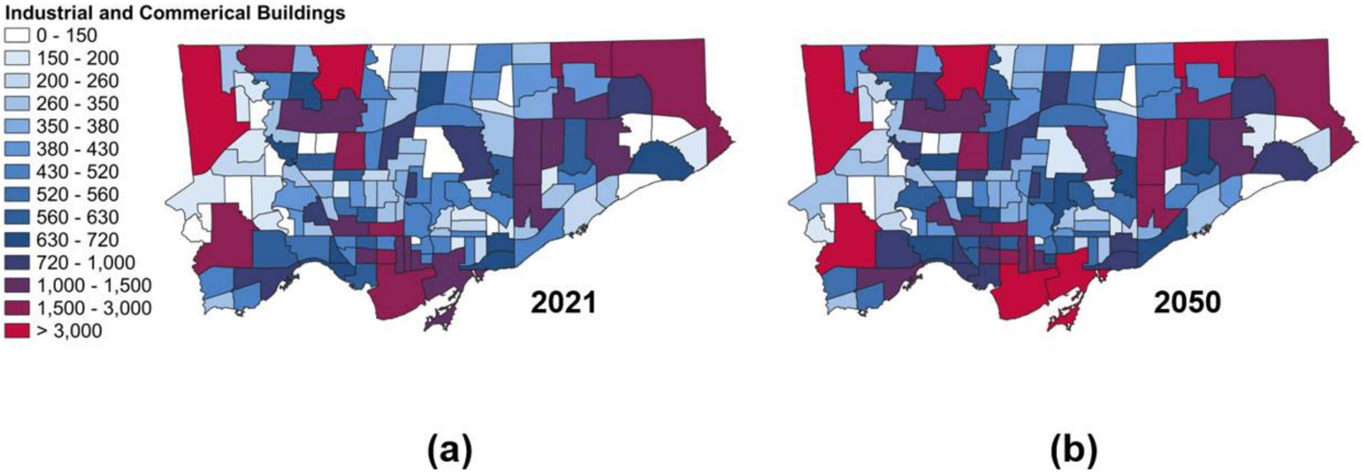


Figure 26: Maps of modelled I&C building distribution in (a) 2021 and (b) 2050.

4.1.3 Core Electrical Efficiency

Domestic Appliance (Non-Heat) Efficiency Projection

The domestic electrical efficiency projections were developed using appliance turnover as the mechanism for energy use reduction. Within the modelling, consumers are assumed to upgrade to a new appliance at the end of an average appliance lifetime, either to:

- an appliance with an average improvement in energy consumption, which was based on the Canada-wide energy use dataset containing annual energy consumption by appliance type; or,
- the most efficient available appliance, the energy consumption of which was taken from the Energy Star website.

Figure 27 shows the high-level methodology used to generate the domestic appliance efficiency projections.

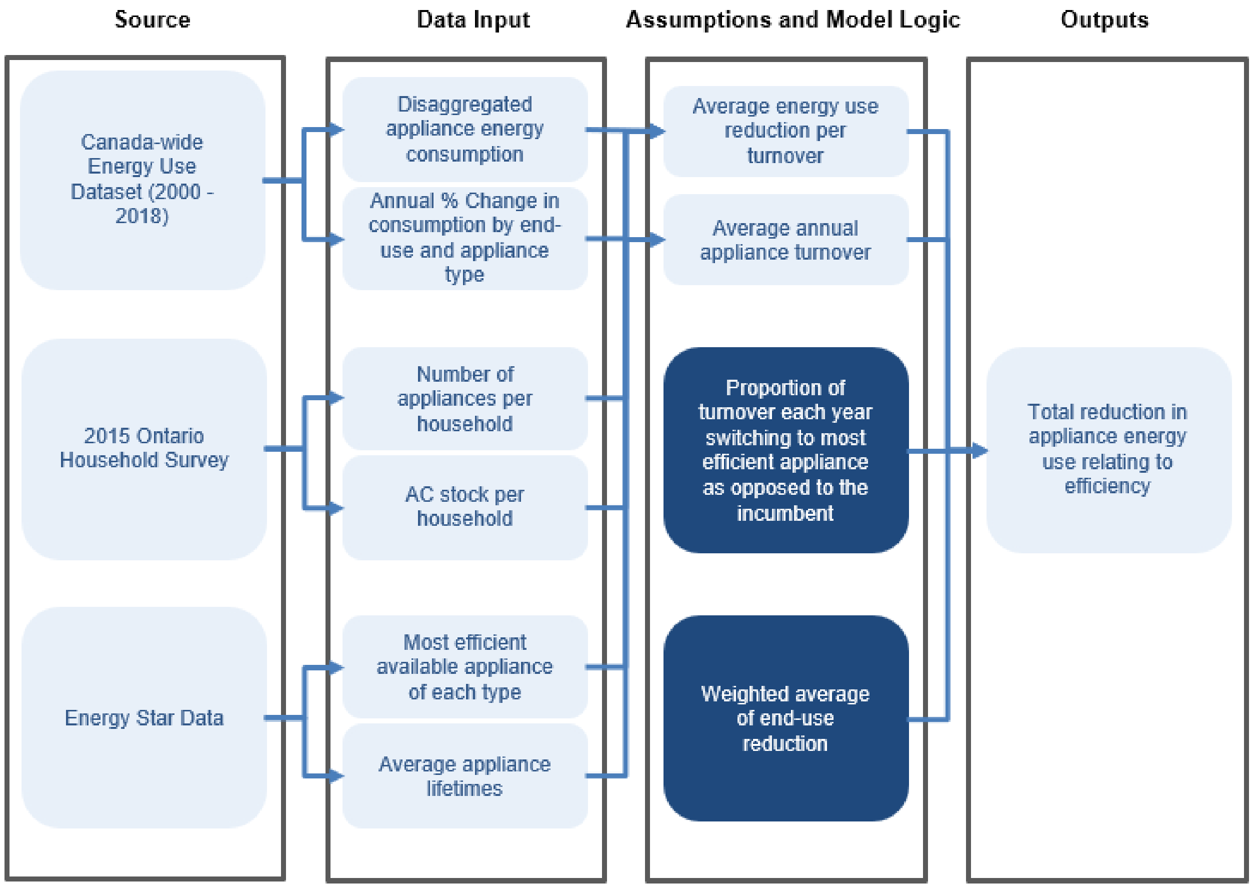


Figure 27: Domestic appliance efficiency projection methodology[17,18,19,20].

Using 2018 Conservation and Demand Management (CDM) data provided by Toronto Hydro, it was determined that the average participation rate of a residential appliance program was 1.5% of the total residential customers. In 2018, five residential appliance programs were available to consumers. As such, the Low scenario was formulated such that 7.5% of annual appliance turnover was to the most efficient appliance, in line with potential CDM intervention impacts. The remaining scenarios are summarized in Table 5 below.

[17] National Resources Canada, Canada-wide Energy Use Dataset | Energy Efficiency Trends Analysis Tables, 2000 – 2018
[18] National Resources Canada, 2015 Survey of Household Energy Use (SHEU-2015) Data Tables , 2015
[19] National Resources Canada, Energy Star | Choosing and Using Appliances With EnerGuide, 2013

Table 5: Scenario assumptions for domestic appliance efficiency projections.

Scenario	Description	Energy use reduction by 2050
Low	1.5% x 5 = 7.5% of annual turnovers switch to most efficient appliance	11%
Medium	Intermediate reduction between Low and High	24%
High	100% of appliances are turned over to most efficient by 2050	37%

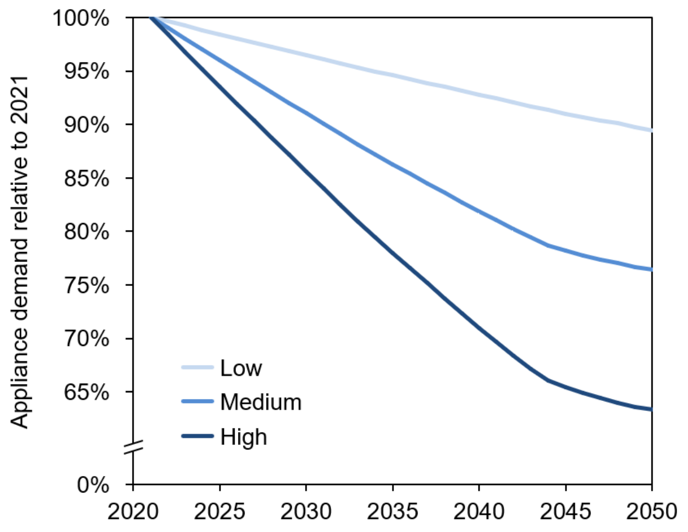


Figure 28: Domestic appliance (non-heat) energy demand reduction relative to 2021.

As shown in Figure 27, a key data input in generating the domestic appliance energy efficiency projections was the average number of appliances per household. These data were obtained from the National Comprehensive Energy Use Database[20] and are shown in Table 6.

Table 6: Historic average number of appliances per household.

Appliance	Per household stock (2018)
Refrigerator	1.28
Freezer	0.50
Dishwasher	0.57
Clothes washer	0.76
Clothes dryer	0.79
Range	1.00
Air conditioning (AC)	0.86[21]
Small appliances	17.35

An appliance growth projection was generated, where the per household stock for all appliances (excluding AC and small appliances) was assumed to be constant throughout the modelled time period, based on the observation that there was minimal historic growth in these appliances. Conversely, for AC and small appliances, a continuation of recent historical trends was assumed as shown in Figure 29.

[20] Natural Resources Canada, Residential Sector Canada Table 37: Appliance Stock by Appliance Type and Energy Source

[21] Toronto Public Health, Protecting Vulnerable People from Health Impacts of Extreme Heat, July 2011

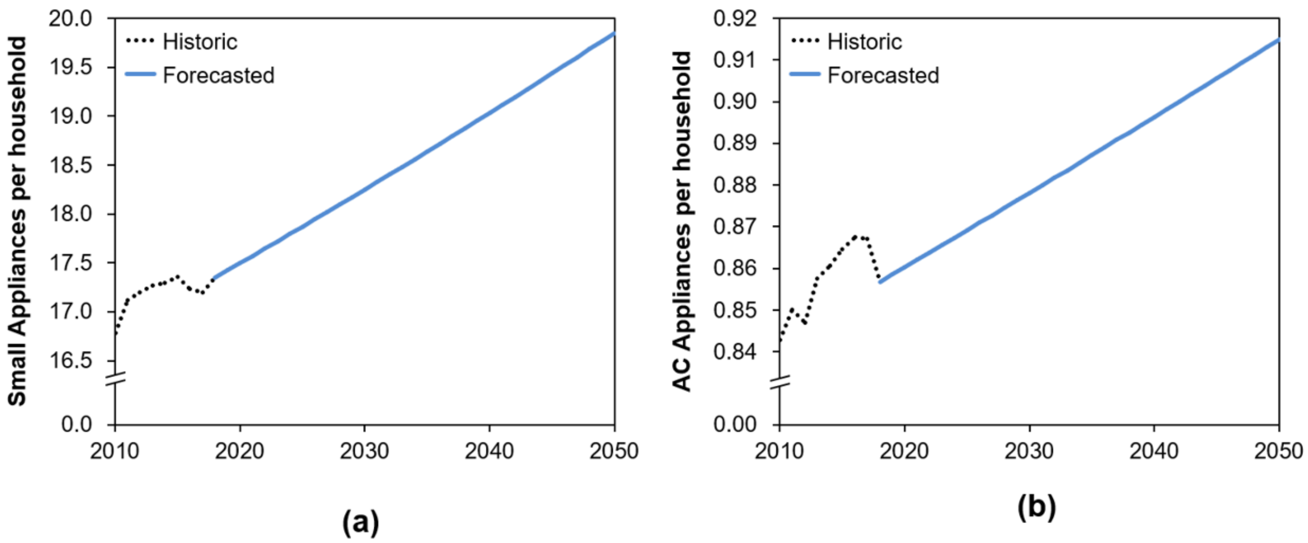


Figure 29: Growth projection for (a) small appliances and (b) AC units per household.

Industrial and Commercial Electricity (Non-Heat) Efficiency Projection

Figure 30 shows the high-level methodology used to create the I&C electricity efficiency projections. The same methodology was utilized for the I&C thermal efficiency projection, discussed in further detail in Section 4.2.3.

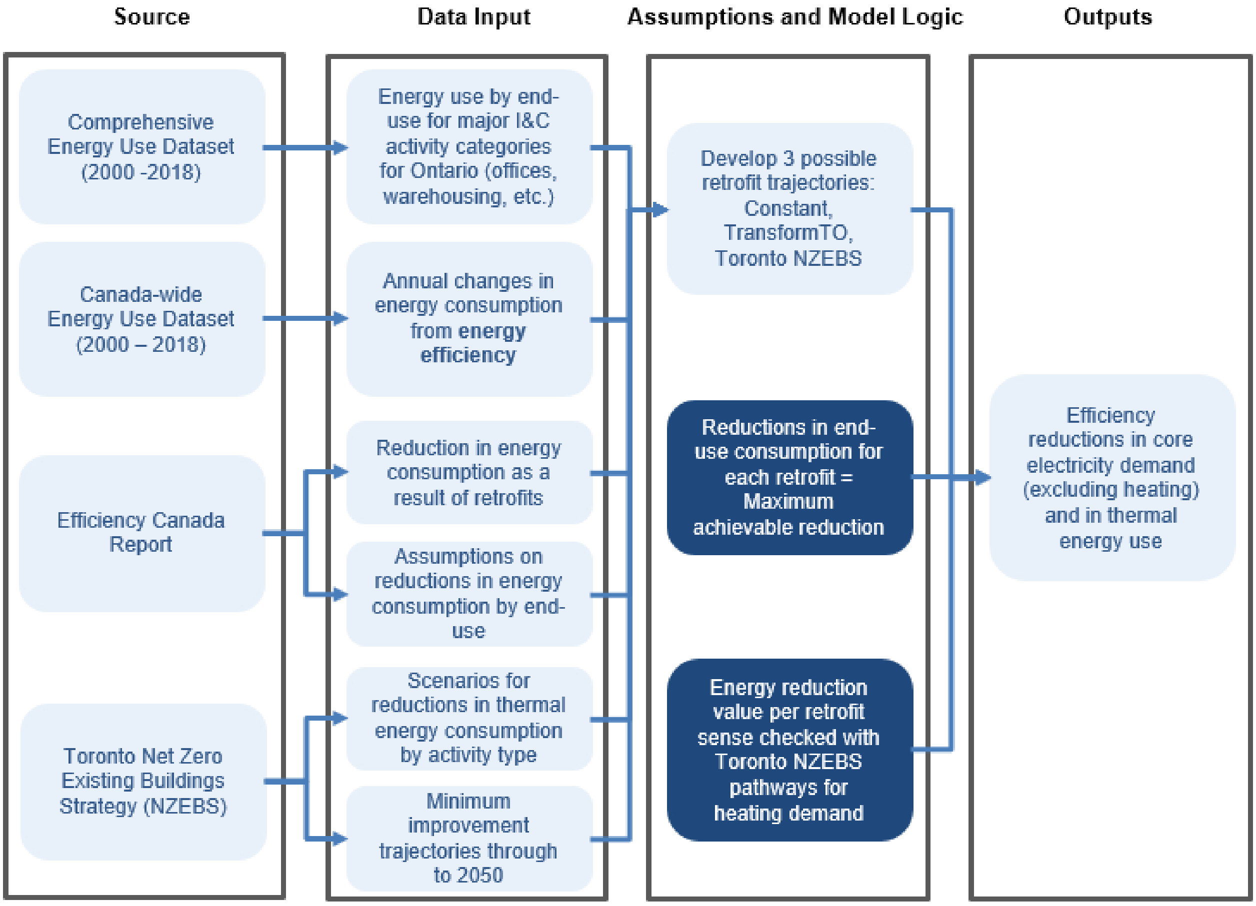


Figure 30: Methodology for I&C electricity and thermal efficiency Projections[22,23,24,25].

Canada-level data on the annual change in energy consumption from energy efficiency was used to develop the Low scenario, which follows a continuation of historic trends. For the Medium and High scenarios, energy use reductions were assumed to be driven by retrofits, with the reduction values by end-use taken from a report by Efficiency Canada and Carleton University[24]. The authors state that the retrofit reductions cited "go further than most current practice but stop well short of current best-practice deep retrofits", and thus can be categorized as an intermediate between incremental improvements and best in class improvements. The differentiation between the Medium and High scenarios were the retrofit rates, with the Medium scenario accomplishing 60% retrofits by 2050 and the High scenario achieving 100% retrofits in the same timeframe. Table 7 below summarizes the scenario descriptions that serve as the basis for the electricity efficiency projection. Figure 31 shows the resulting scenario projections out to 2050.

Table 7: Scenario description and electrical (non-heat) energy use reduction by 2050 relative to 2021.

Scenario	Description	Non-heat electrical reduction in 2050
Low	Continuation of historic energy efficiency trends	5%

[22] Natural Resources Canada Comprehensive Energy Use Database (2000 – 2018) | Commercial/Institutional Sector – Ontario
[23] Natural Resources Canada, Canada-wide Energy Use Database (2000 – 2018) | Total End-Use Sector - Energy Use Analysis
[24] Efficiency Canada and Carleton University, Canada's Climate Retrofit Mission, June 2021
[25] City of Toronto, City of Toronto NetZero Existing Buildings Strategy and Technical Appendix, 2021

Scenario	Description	Non-heat electrical reduction in 2050
Medium	Intermediate trend (66% retrofits by 2050)	18%
High	NZ40 rate (100% retrofits by 2050)	27%

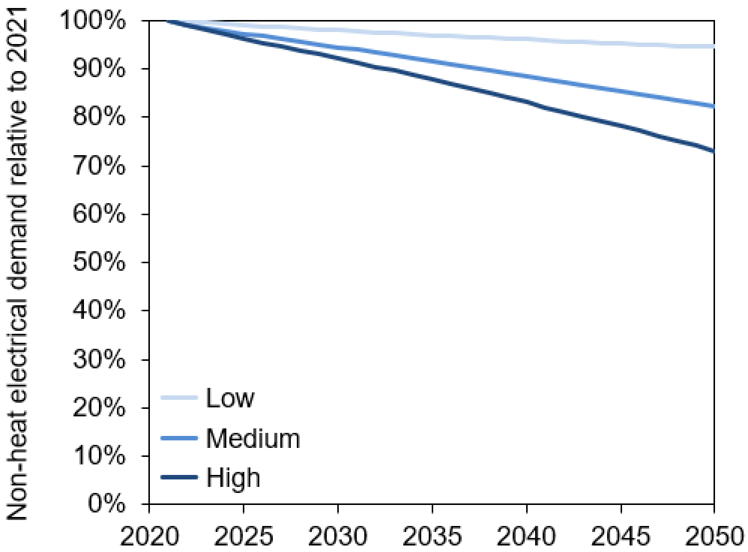


Figure 31: I&C projections for electricity (non-heat) energy demand reduction relative to 2021.

4.1.4 Flexibility Measures

Time-of-use (ToU) tariffs and energy storage are the primary flexibility measures relevant to core demand in this analysis. The approach to modelling the impact of ToU tariffs in the core demand projections is described below, while the modelling of domestic and I&C battery storage is discussed in more detail separately in section 4.5.

Under the Regulated Price Plan (RPP), a large fraction of domestic and small commercial customers (91%) in Toronto were on ToU tariffs before September 2020. In October 2020, the Consumer Choice regulation issued by the Ontario Energy Board (OEB) enabled price plan switching for RPP customers which has resulted in a reduction in the fraction of customers on the ToU plan[26], as shown in Figure 32.

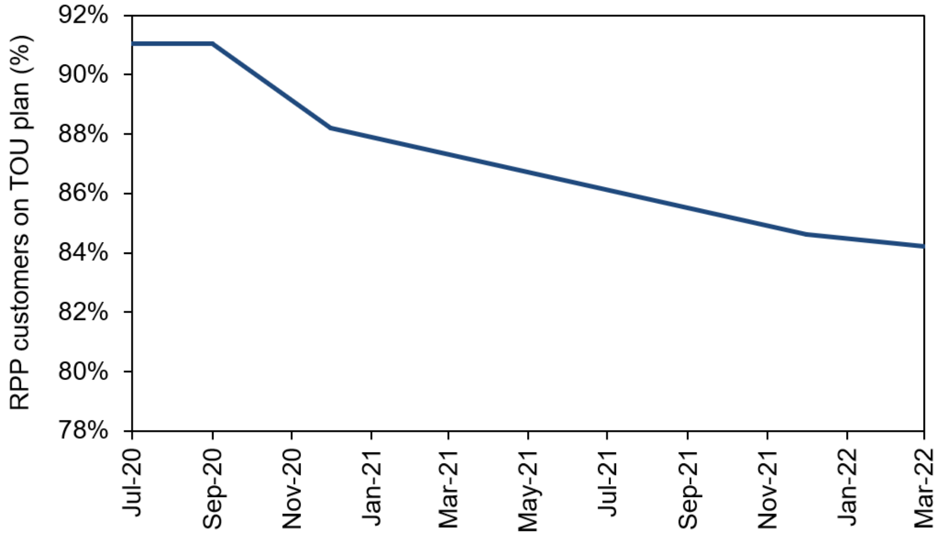


Figure 32. Price plan switching of eligible customers between ToU and tiered rate plans since the introduction of Consumer Choice, Ontario, Canada.

It is worth noting that a large portion of the observed switches occurred in the first few months after the regulation was implemented (47%). The latest available update on switching is from March 2022, which shows that 84% of eligible RPP customers remain on ToU tariffs. The current level of ToU tariff penetration across the Toronto Hydro network is captured in the modelling through the core demand profiles used (see Section 5.1). The March 2022 level of ToU tariff uptake is maintained throughout the modelling period for all scenarios.

[26] Ontario Energy Board (OEB), Frequency of Regulated Price Plan Switching Under Consumer Choice, 2021

4.2 Low Carbon Heating

There are two main pathways to decarbonize heat, each relying on varying levels of electrification and gas decarbonization. The key themes in each of these pathways are described in Figure 33.

Two main pathways to decarbonize heat

High Electrification	**Decarbonized Gas**
A high electrification scenario promotes electrification of heat using an increasingly decarbonized electricity grid. There is a high uptake of **heat pumps**. All heat is electrified, and the gas grid is decommissioned.	A decarbonized gas scenario promotes the conversion of the gas grid to hydrogen or other low carbon gases (e.g., biomethane). Buildings remain predominantly heated by **gas boilers and/or furnaces,** shifting from natural gas to low carbon alternatives.

In addition, **district heating** and **energy efficiency** can play a role in both pathways.

Figure 33: Heat pathway diagram.

The High Electrification and Decarbonized Gas scenarios represent two extremes of the future; in reality, the pathway for heat decarbonization in Canada, and Toronto particularly, could be a mix of these components, with different regions potentially opting for different technological solutions.

We developed scenarios for key drivers of the transition to low carbon heating, as laid out in Table 8. For energy efficiency and heating technologies, four scenarios representing incremental levels of ambition were generated using Element's consumer choice modelling (described in Section 4.2.1). The efficiency scenarios relate to the level of uptake of fabric improving efficiency measures among the region's building stock Note that "Early High" is used for heating technology uptake as opposed to "Very High" – this is because the scenario reaches the same level of heating technology deployment as the "High" scenario, but at a faster rate. As with other sectors, these technology specific uptake scenarios have then been mapped to a corresponding scenario world, as shown in Table 8.

Table 8: Scenario world mapping for low carbon heating.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic thermal efficiency	Low	Medium	High	Low	Very High	Low
I&C thermal efficiency	Low	Medium	High	Low	Very High	Low
Domestic heating technologies	Low	Medium	High		Early High	
I&C heating technologies	Low	Medium	High		Early High	
Gas heating in 2050	High	Medium (due to hybrid heat pumps)	None		None	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	

4.2.1 Modelling Approach

As discussed in Section 3.1, bottom-up consumer choice models were used to determine the uptake of decarbonized heating technologies. This analysis was predicated upon the locationally granular building stock trajectories (for domestic and non-domestic building types) described in Section 4.1.2. The domestic and I&C building trajectories were treated separately because their growth is driven by distinct factors.

Element Energy has a heating technology uptake model that assesses the business case of various heating technologies (Figure 34Figure 34) for different domestic and I&C building stock archetypes. In this model, the heating technologies are assumed to have a set lifetime (15 years for all scenarios), at the end of which the consumer chooses which technology to replace it with based on various factors. These factors include the following:

- Technology prices (capital costs and operational costs) including the available grants.
- Fuel and electricity costs.
- Thermal efficiencies for each archetype.
- Awareness of technology for domestic and I&C consumers.
- Willingness-to-pay for each archetype.
- Government policy.

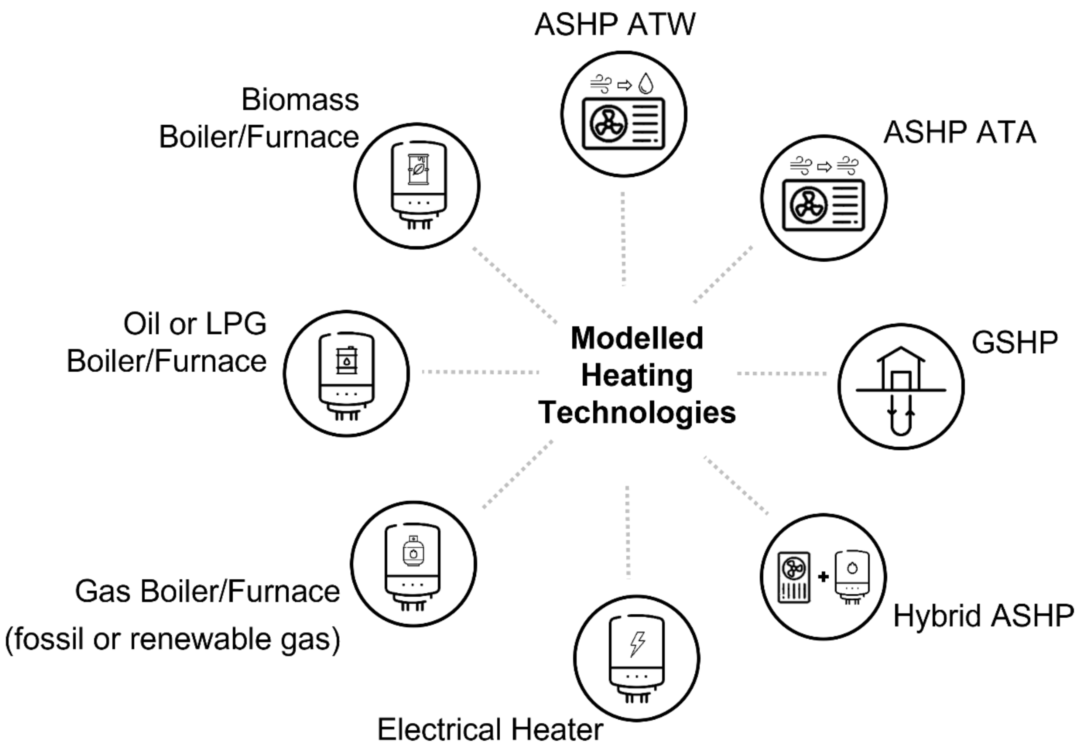


Figure 34: Modelled heating technologies.
Acronyms: ASHP ATW: air source heat pump – air to water; ASHP ATA: air source heat pump – air to air; GSHP: ground source heat pump; Hybrid ASHP: hybrid air source heat pump.

District heating is not classified as a distinct heat source in the consumer choice model, since the fundamental technologies used for heat generation are no different than those used in centralized applications; what differs is the distribution system. In addition to this, the driving factors leading to district heat uptake are more complex than for other low carbon heating options – uptake is related to variables beyond an individual consumer's choice or control, such as the heat density of the city, the proximity to existing or future significant sources of waste heat, or a region's planning laws. Considering Toronto specifically in conjunction with these general factors, two further points led to the decision to exclude district heating from our analysis of heat decarbonization in this case:

- Currently, fewer than 1% of buildings in Toronto are heated by district heating[3].
- Future rollout of district heating would affect the location and clustering of electrical loads, rather than the overall demand. At the geospatial resolution of this modelling (neighbourhoods and municipal stations), the impact of this is expected to be very small.

4.2.2 Policy Assumptions

As existing fossil fuel technologies are currently cheaper to install and run in many cases, top-down government intervention is assumed to be essential to drive uptake of decarbonized heating technologies.

IESO's Pathway to Decarbonization[27] reflects a ban on fossil fuel heating in new homes by 2030 and existing homes by 2035. This suggests that the most likely policy intervention going forward to decarbonize heat will be to phase out heating technologies that depend on high carbon fuels such as gas, oil and LPG. Element Energy's previous engagement with building-level heat professionals suggests that, if such policy interventions are to occur, they will first target new builds, followed by off-gas existing buildings, followed by on-gas existing buildings, depending on the general policy ambition.

[27] The Independent Electricity System Operator, Pathway to Decarbonization – Assumptions for Feedback, March 2022

Table 9 lists the assumed dates for when different existing heating technologies are phased out in order to reach net zero by either 2040 or 2050 depending on scenario. These dates apply to both domestic and I&C customers.

Table 9: Ban dates for choosing Business As Usual heating fuels in building types (new builds or existing builds).

Scenario	Existing heating fuel	New builds	Existing buildings	Ban date on Hybrid Heat Pump
Low	Gas	2035	No restrictions	No restrictions
	Oil & LPG	2035	2035	2035
Medium	Gas	2030	2035	No restrictions
	Oil & LPG	2030	2030	2030
High	Gas	2030	2035	2035
	Oil & LPG	2027	2027	2027
Early High	Gas	2025	2025	2025
	Oil & LPG	2025	2025	2025

Canada's Greener Homes Grant

The Canadian Greener Homes grant, effective from December 2020, grants up to $5,000 towards heat pumps and energy efficiency measures. The scheme can be used for a selection of low-carbon technologies, including those not used for heating (e.g. solar PV). The heat pump technologies that are supported by the scheme are listed below:

- Air-Source Heat Pump: Air-to-Air (ASHP ATA).
- Air-Source Heat Pump: Air-to-Water (ASHP ATW).
- Ground-Source Heat Pumps (GSHP).

There is currently no support for hybrid heat pumps under this scheme. The Greener Homes Grant is expected to last at least 7 years since its initiation, but this may be extended. Within our heating technology uptake scenarios, four policy scenarios were created describing a potential future for the Greener Homes Grant. These scenarios differ by level of support by technology, the heating technologies that are supported by the scheme and the scheme end date. The scenario mapping is shown in Table 10 below.

Table 10: The Greener Homes Grant policy support and duration assumed for each technology and scenario.

Scenario	GSHP	ASHP	Hybrid ASHP	End date
Low	$5,000	$4,000	$0	2027
Medium	$5,000	$4,000	$4,000	2030
High	$5,000	$4,000	$0	2030
Early High	$5,000	$4,000	$0	2035

4.2.3 Thermal Efficiency

Domestic Thermal Energy Efficiency Projection

For each building archetype, thermal efficiency trajectories were developed that then fed into the heat pump and load modelling on an archetype-specific basis. These trajectories are based on the following three components for each scenario:

- The baseline thermal demand of each archetype.
- The post-retrofit thermal demand of each archetype.
- The retrofit rate.

The baseline thermal demand was determined using data from the National Energy Use Database[28]. A post-retrofit thermal demand was then established for each archetype and scenario. For the Medium and High scenario, this is based on thermal demands after comprehensive building retrofits by building type and age based on a report by Efficiency Canada and Carleton University[24]. These were broadly aligned with post-retrofit demands for different building types from The City of Toronto's Net Zero Existing Buildings Strategy[29] (NZEBS), falling within the range of their *Recommended* and *Aggressive* scenarios. For the Very High scenario, which aligns with TransformTO's[3] Net Zero by 2040 (NZ40) scenario, deeper retrofits are assumed for each archetype, aligning with a total building energy efficiency gain of 75%. In the Low scenario, lower efficiency gains are assumed, and the post-retrofit thermal demand is aligned to TransformTO's Business as Planned (BAP) scenario, with a total building energy efficiency gain of 35%.

The retrofit rate represents the proportion of buildings retrofitted by year. The Low and Very High scenario retrofit rates are drawn from TransformTO BAP and NZ40, respectively. The High scenario retrofit rate is based upon the progress rate from NZEBS, while the Medium scenario retrofit rate sits midway between the Low and the High scenarios. Figure 35 shows the proportion of buildings retrofitted by 2050 for each scenario.

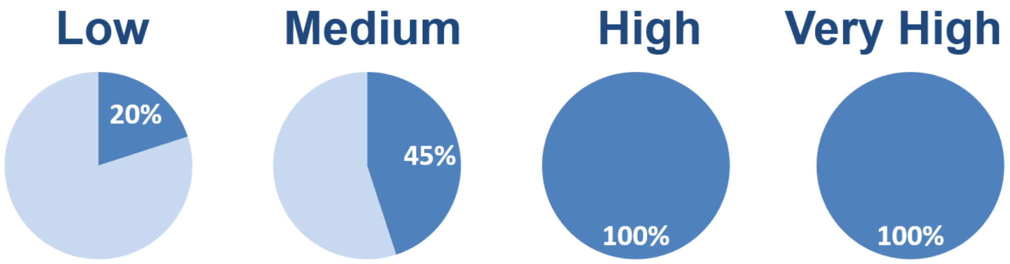


Figure 35: Proportion of domestic buildings retrofitted by 2050 by scenario.

The resulting thermal energy efficiency projections are shown below in Figure 36. Due to the deeper retrofits assumed in order to align the Very High scenario with TransformTO's NZ40 scenario, the overall thermal demand reduction achieved in the Very High scenario is higher than the citywide reduction of 73% put forth by the *Aggressive* scenario from the Toronto Net Zero Existing Buildings Strategy.

[28] Natural Resources Canada, National Energy Use Database – Ontario, 2018
[29] The City of Toronto, Net Zero Existing Buildings Strategy, May 2021

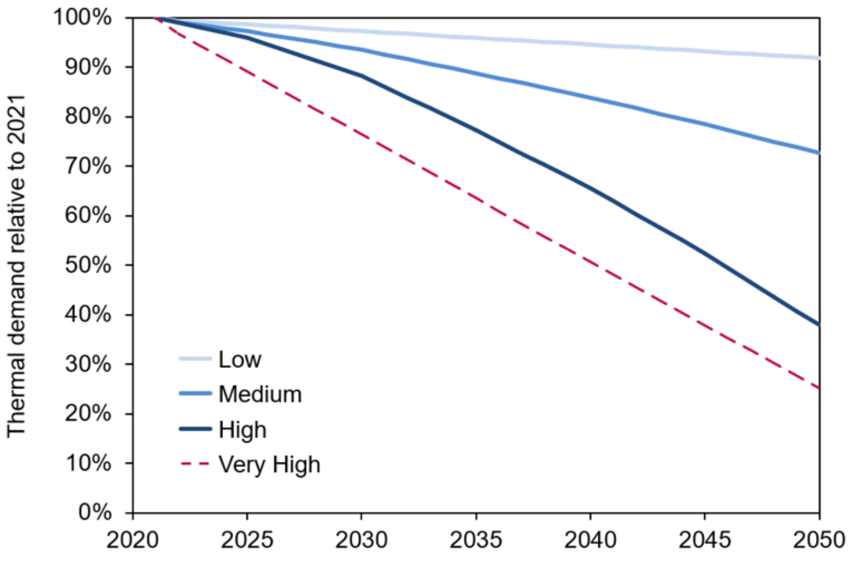


Figure 36: Domestic thermal energy efficiency projections out to 2050.

Industrial & Commercial Thermal Efficiency Projection

The baseline thermal demand by I&C archetype was determined using Ontario-level data from the Comprehensive Energy Use Dataset[28]. For the Low scenario, reductions in demand (and retrofit rate) are a continuation of energy use reductions from energy efficiency as taken from the Energy Efficiency Trends Analysis Tables of the National Energy Use Database[17]. The Medium and High scenarios base thermal demand reduction on retrofits, where the post-retrofit thermal demands by archetype were determined using the percentage reduction in thermal demand by end use from the Efficiency Canada and Carleton University report. These values are broadly aligned with the values from the *Recommended* pathway of The City of Toronto's Net Zero Existing Buildings Strategy. The retrofit rate for the High scenario is taken from the *Aggressive* pathway of The City of Toronto's Net Zero Existing Buildings Strategy, while the Medium scenario retrofit rate is the average of the BAP rate of TransformTO and the rate of the High scenario. Table 11 below shows the scenario descriptions that serve as the basis for the thermal efficiency projections. A Very High scenario was incorporated which matches the TransformTO NZ40 retrofit rate and retrofit reduction values. This represents a particularly ambitious scenario option since it exceeds the 60% reduction used in the *Aggressive* pathway of the Toronto Net Zero Existing Buildings Strategy which is based on "best in class" retrofits.

Table 11: Scenario description and thermal energy use reduction by 2050 relative to 2021.

Scenario	Description	Heating reduction in 2050
Low	Continuation of historic energy efficiency trends	10%
Medium	Intermediate trend (66% retrofits by 2050)	22%
High	NZ40 rate (100% retrofits by 2050)	33%
Very High	NZ40 rate and NZ40 reduction value	75%

The resulting thermal efficiency projections are shown below in Figure 37.

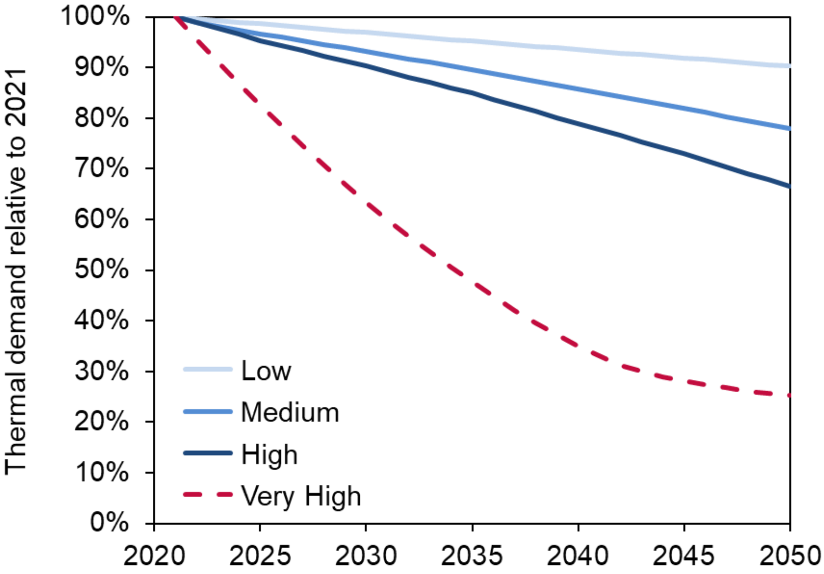


Figure 37: I&C thermal efficiency projections out to 2050.

4.2.4 Uptake Modelling Results

Element Energy's in-house consumer choice model was used to develop four scenarios for the uptake of low carbon heating across the domestic and I&C sectors, as described in Section 4.2.1. These scenarios represent a wide range of decarbonization ambition, resulting in varied levels of the uptake of heat pumps. The trajectories for the uptake of full electric heat pumps are shown below in Figure 38. The following sections detail the modelling assumptions and results for each of these scenarios.

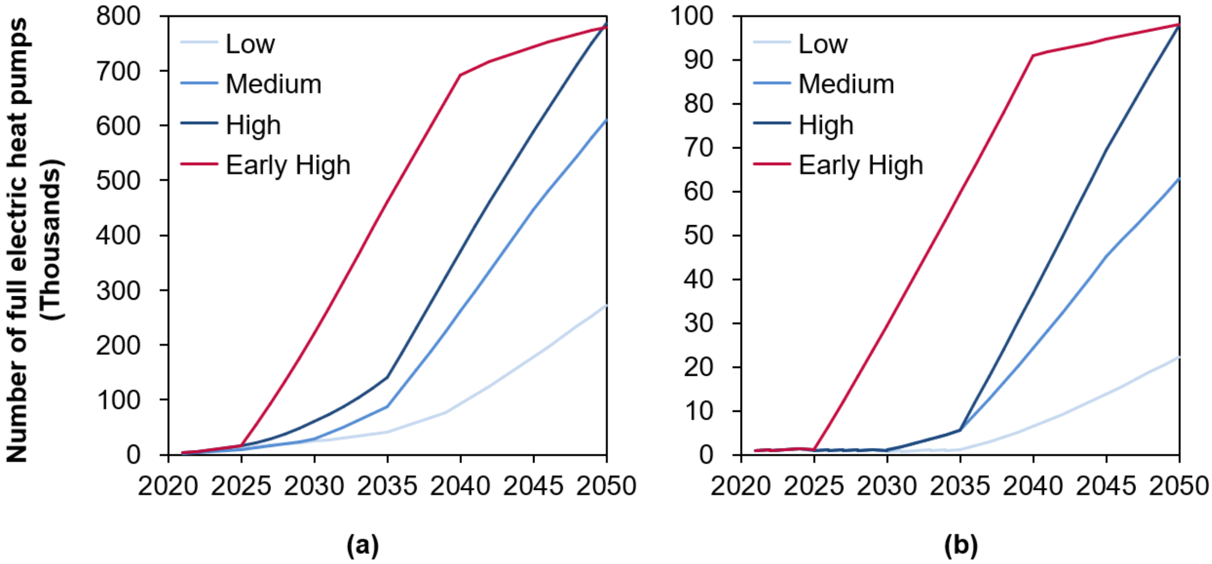


Figure 38: Comparison of full electric heat pumps modelled out to 2050 between scenarios for the (a) domestic and (b) I&C building stock.

Low Scenario - Steady Progression

In the Low scenario two policy interventions are considered, a ban on fossil fuel heating in new homes from 2035 and a ban on fossil fuel heating in off-gas properties from 2035 (Table 12Table 12). Additionally, the Greener Homes Grant is not assumed to last longer than the currently proposed duration of 7 years (from 2020). A low rollout in energy efficiency measures is modelled in this scenario. The resulting heating technology breakdown can be seen in Figure 39. This scenario fails to fully decarbonize the heating sector which still relies heavily on natural gas in 2050. The heat pumps that come into operation are predominantly in the new build and off gas grid sectors. Since there is no I&C sector support from the Greener Homes Grant, there is little financial motivation for heat pump uptake until policy forces the switch. This scenario suggests that without government intervention, the business case for gas heating will remain strong, resulting in low uptake of low-carbon heating technologies.

Table 12: Scenario assumptions for low-carbon heating technology uptake in the Low Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2035	No restrictions	No restrictions
Other fossil fuel-based heaters	2035	2035	2035
Greener Homes Grant end date	2027	**Energy efficiency rollout scenario**	Low

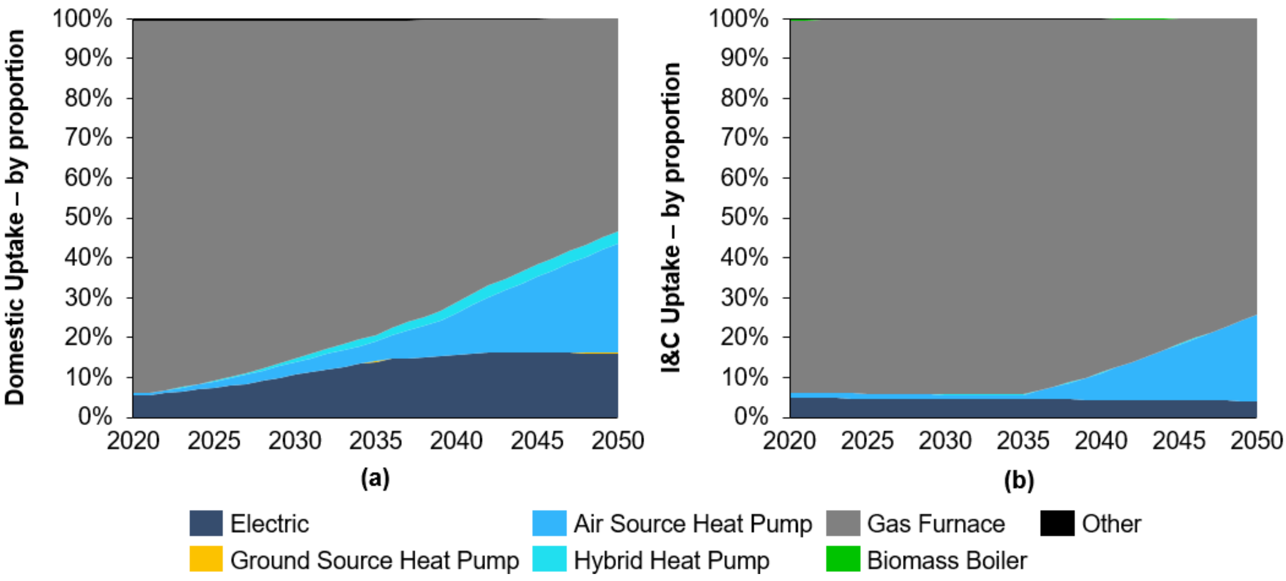


Figure 39: (a) Domestic and (b) I&C low carbon heating technology uptake - Low Scenario.

Medium Scenario – System Transformation

The Medium scenario is a gas-backed scenario and is based upon the *Hybrid Heating* pathway from The Canadian Gas Association's (CGA) report on pathways to achieving net zero building stock by 2050[30]. The report outlines three different decarbonization scenarios: *Efficiency*, *Hybrid Heating* and *Renewable Gases*. Each of these pathways are designed to meet net zero by 2050 by relying on the following factors to varying degrees depending on the scenario:

- Energy efficiency improvement programs.
- Stricter building regulations.
- Heat pumps (including hybrid heat pumps).
- Use of 'renewable gases', particularly renewable natural gas (RNG).
- Emissions offsets.

Table 13 shows the level of emissions reduction achieved in each of the three scenarios via the above drivers, according to the analysis.

Table 13: Canadian Gas Association Pathways showing the proportion of present-day emissions removed.

CGA Scenario	Gas demand reductions	Renewable gases	Emissions Offsets
Efficiency	43%	43%	14%
Hybrid Heating	56%	35%	9%
Renewable Gases	30%	55%	15%

The *Hybrid Heating* pathway has the lowest reliance on emissions offsets (as well as renewable natural gas) and was selected to inform the gas-backed Medium scenario in this analysis.

In the Medium scenario the ban on fossil fuel heating in new builds is brought forward to 2030 and existing off-gas properties can no longer choose non-gas fossil fuel heating from 2030 (Table 14Table 14). Existing on-gas properties are no longer able to select gas heating from 2035. To simulate the *Hybrid Heating* pathway in the consumer choice model, hybrid heat pumps are not phased-out from sales at this date, unlike in the other net zero compliant scenarios. Additionally, an extension to the Greener Homes Grant to support hybrid heat pumps as well as pure electric ones is modelled. A medium rollout of energy efficiency measures is modelled in this scenario.

Table 14: Scenario assumptions for low-carbon heating technology uptake in the Medium Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	No restrictions
Other fossil fuel-based heaters	2030	2030	2030
Greener Homes Grant end date	2030 with hybrids	**Energy efficiency rollout scenario**	Medium

[30] The Canadian Gas Association, Potential Gas Pathways to Support Net Zero Buildings in Canada, October 2021

In the Medium scenario a considerable proportion of heating systems in both the domestic and I&C sectors switch to hybrid heat pumps, making use of retained gas infrastructure (Figure 40Figure 40). It is worth noting that the source of the gas is not modelled for these scenarios; however, for the Medium scenario to be consistent with the 2050 net zero target, all fossil natural gas would need to be replaced with renewable natural gas, per the CGA's recommendations.

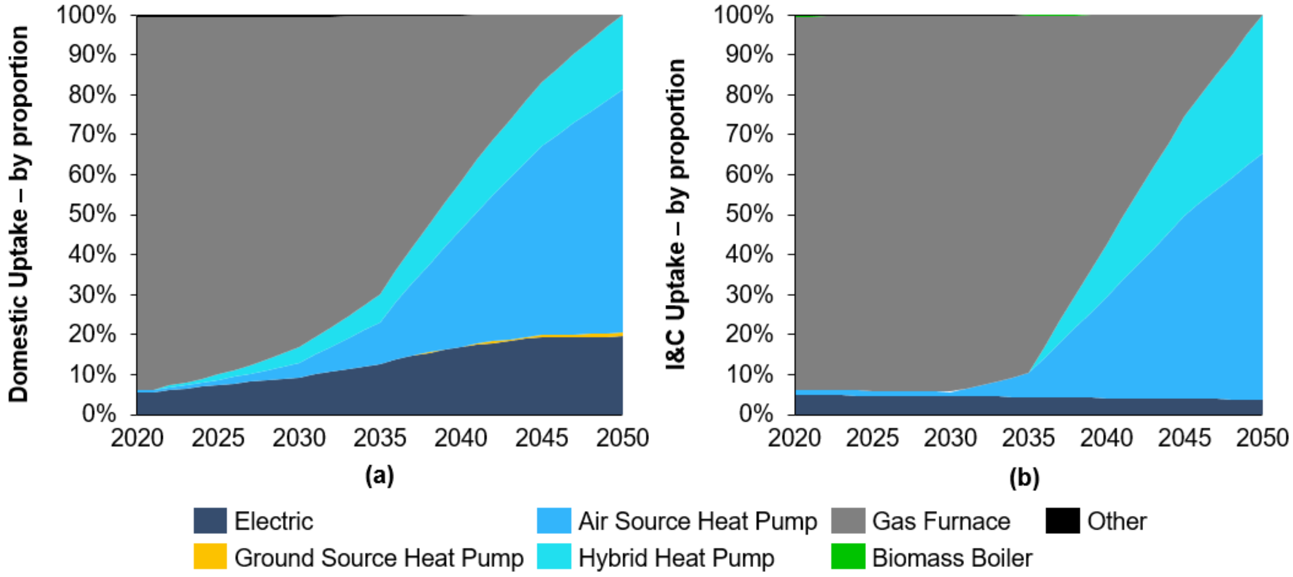


Figure 40: (a) Domestic and (b) I&C low carbon heating technology uptake - Medium Scenario.

High Scenario – Consumer Transformation

The High scenario relies on the full electrification of the heating sector. Like the Medium scenario, an extension to the Greener Homes Grant to 2030 is modelled; however, this is modelled without the additional support for hybrid heat pumps in this scenario. A ban on gas heating in new builds is enforced in 2030, with the ban on other fossil fuel heating brought forward to 2027, for existing and new builds (Table 15Table 15). In 2035, a ban on gas boilers is enforced for existing buildings, which includes switching to gas hybrid heat pumps. These bans, coupled with an assumption of a 15-year average lifetime of heating technologies, ensures a complete phase out of gas heating by 2050. A high rollout of energy efficiency measures is modelled in the High scenario. The resulting heating breakdown in Figure 41 shows that, for both the domestic and I&C sectors, the entire building stock is either using electric heating or fully electric heat pumps by 2050.

Table 15: Scenario assumptions for low-carbon heating technology uptake in the High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	2035
Other fossil fuel-based heaters	2027	2027	2027
Greener Homes Grant end date	2030	**Energy efficiency rollout scenario**	High

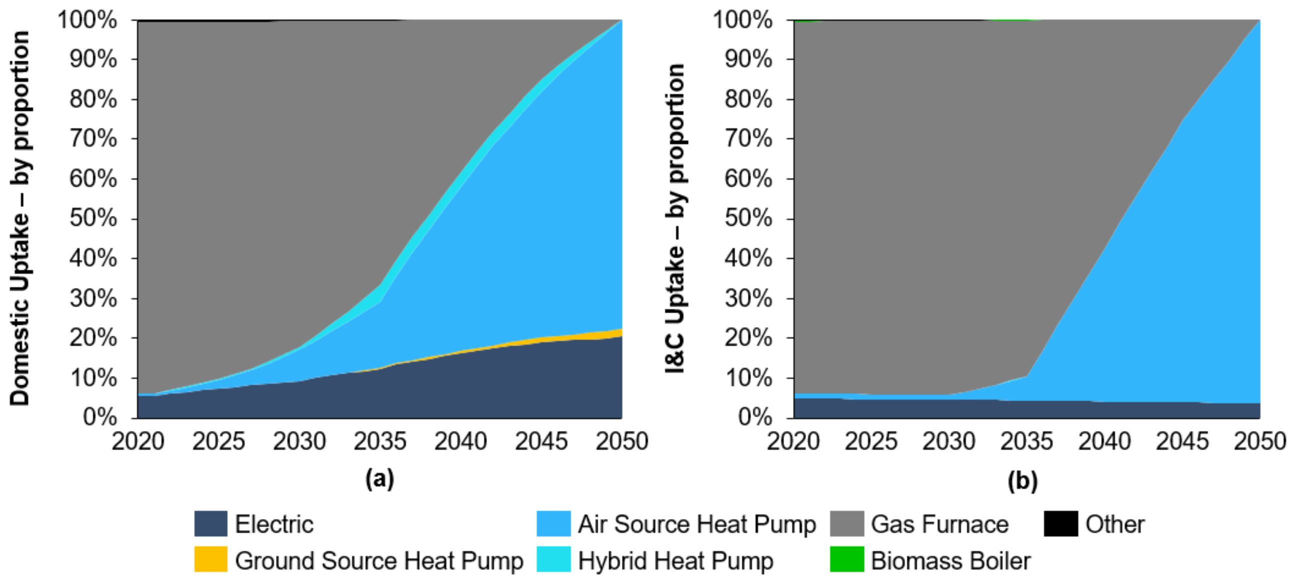


Figure 41: (a) Domestic and (b) I&C low carbon heating technology uptake - High Scenario.

Early High – Net Zero 2040

The Early High scenario reflects the highest government ambition in the scenarios modelled, with a 2040 net zero target. The scenario assumptions used in this scenario reflect early government action, with an all-encompassing ban on gas and other fossil fuel heating in 2025. The Early High scenario assumes a further extension of the Greener Homes Grant beyond the Medium and High scenarios to 2035, without any support for hybrid heat pumps (Table 16Table 16). A very high rollout of energy efficiency measures is also modelled in this scenario. The resulting heating technology breakdown in Figure 42 shows a fully electrified heating system by 2040 in both the domestic and I&C sectors.

Table 16: Scenario assumptions for low-carbon heating technology uptake in the Early High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2025	2025	2025
Other fossil fuel-based heaters	2025	2025	2025
Greener Homes Grant end date	2035	**Energy efficiency rollout scenario**	Very High

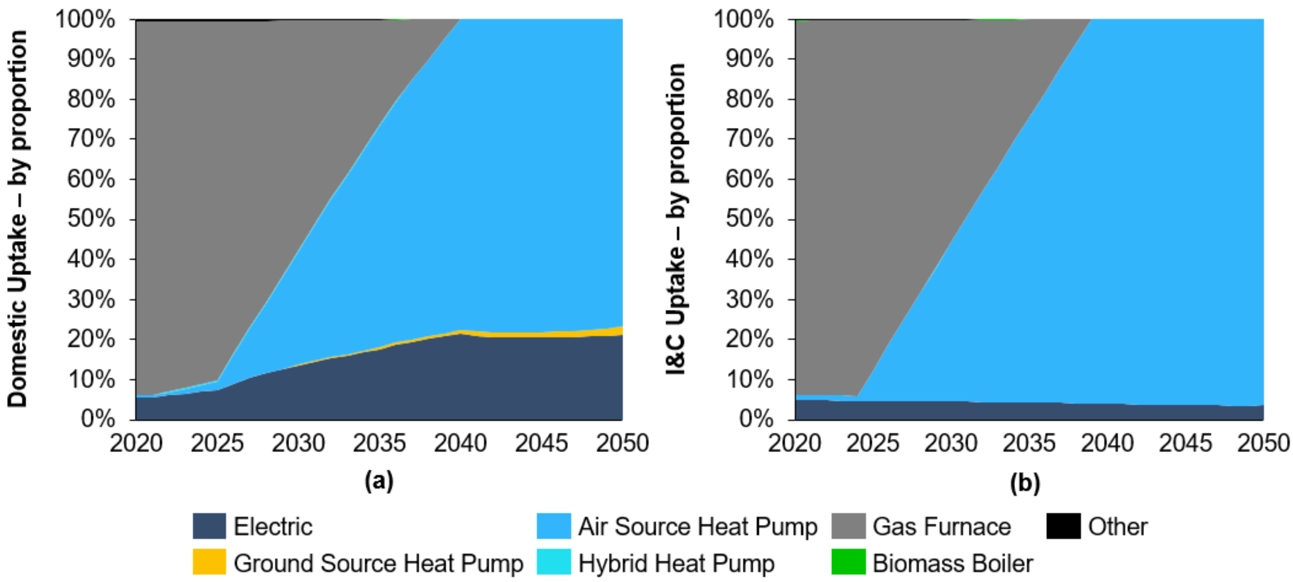


Figure 42: (a) Domestic and I&C (b) Low carbon heating technology uptake - Early High Scenario.

4.3 Electrification of Transport

There are several modes of transport relevant to Toronto, and in a similar manner to domestic and I&C buildings, different factors and market forces influence the manner in which different transport segments will decarbonize. Hence the penetration of electric vehicles (EVs) for each segment may differ in a given scenario world. The different sizes and requirements of transport types also lead to different technology mixes within sectors once decarbonized, as well as different assumptions for the energy required per unit of distance travelled. The main technology routes considered in the scenarios are summarized below in Figure 43.

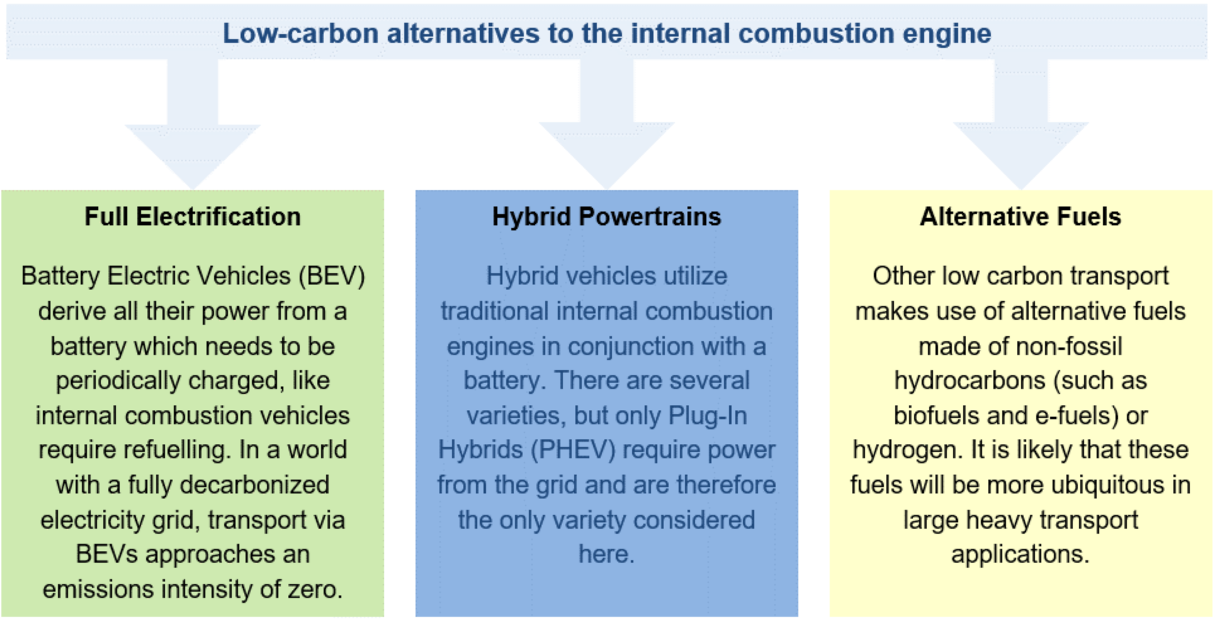


Figure 43: Main transport decarbonization pathways.

For the purposes of this analysis, transport has been segmented into Cars and Light Trucks, Medium- and Heavy-Duty Trucks, Buses, and Rail. Section 4.3.1 explains the electric vehicle uptake modelling process in more depth, while Section 4.3.6 gives an overview of how charging demand from these vehicles is allocated across the network. A summary of the penetration of electrified transport solutions in each of the four scenario worlds is given below in Table 17. The assumptions contained within each scenario are detailed in Sections 4.3.2 to 4.3.5 and 4.3.7.

Table 17: Scenario world mapping for transport electrification.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Cars and Light Trucks	Low	Medium	Medium		High	
Medium- and Heavy-Duty Trucks	Low	Medium	Medium		High	
Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart Charging & V2G	Low	Medium	High	Low	High	Low

4.3.1 Modelling Approach

Electric Car Consumer Model (ECCo)

Element Energy's "Electric Car Consumer model" (ECCo) was used to generate bottom-up technology uptake scenarios for cars and light trucks, which consist of a varying mixture of full electric, hybrid and alternative-fuels based transport options. The model splits the private-individual and corporate-fleet customer bases into 18 archetypes based on attributes such as affluence and willingness-to-pay. The model then contains a parametric representation of consumer behaviour which was developed based on primary research conducted on a sample of 2,000 new car buyers. Within the model, consumers are "presented" with showrooms of future vehicles. Based on the real-world behaviour of the survey participants and the characteristics of consumer types within the model, the model reaches a purchase decision for each modelled individual which is likely to reflect real behaviour. For each model year the different consumer archetypes purchase an array of powertrains, which are typically observed to trend towards low-carbon options over time as the cost of these options fall. These results are then aggregated across all customer archetypes and converted to a total number of new car sales each year, which can also be converted to an overall share of the car stock held by a given technology.

Element Energy has refined this model over the course of the last decade, and it has been used extensively by clients in the UK including the Department for Transport and several electricity distribution businesses. The consumer choice approach it utilizes has consistently been shown to be more effective and accurate than other common approaches such as diffusion models and cost-comparisons. Figure 44 illustrates a high-level overview of the inputs and outputs of ECCo's modelling process.

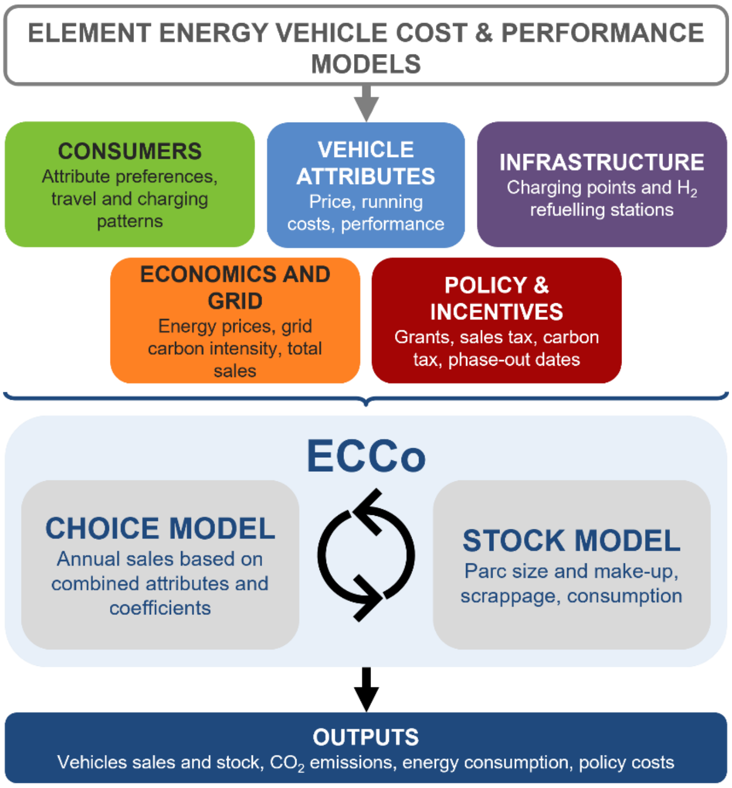


Figure 44: Schematic showing the process utilized by the ECCo model.

The modelling was tailored specifically to reflect the car ownership rates for different vehicle types in Canada and the physical attributes of the car types were also tailored to reflect the averages seen in the Canadian market. Inputs relating to vehicle economics such as tax rates, policy incentives and energy prices were aligned to those applicable in Toronto, including the Canadian Government's incentives for zero-emissions vehicles (iZEV) scheme[31] (the assumptions used align with April 2022 policies). Details of Toronto's infrastructure (such as gas station and charge point locations) were also taken as an input.

This process was able to produce detailed Low, Medium, and High electrification uptake scenarios for Toronto's car and light truck stocks, containing a detailed breakdown of the percentage share of battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) and other fuel types prevalent within the transport stock from the base year (2021) to 2050.

Base Year Vehicle Stock

The base year car and truck stock in Toronto and its composition was found from a range of data sources. Statistics Canada publishes provincial level registration data[32] which splits the stock by car type (passenger vehicle, pickup trucks, etc.) and powertrain (gasoline, diesel, battery electric, etc.). Vehicles are also often split into classes for the purposes of analysis and legislation. For this study, the United States Federal Highways Agency system for car and truck classification is used, where vehicles are assigned to one of eight generic classes. Classes 1-2 contain passenger cars, light trucks, sports utility vehicles (SUVs) and people-carriers, while vehicles in classes 3-8 are medium- and heavy-duty trucks. The separate treatment of different vehicle classes is important to this analysis because the energy consumed per unit distance travelled by an EV, which is a key driver in the uptake model, differs between classes.

It is worth noting that the available data for Toronto lacked detail pertaining to specific use-cases or classes of individual vehicles, apart from a 2016 dataset from the Ontario Data Catalogue[33] which details the stock of commercial and private vehicles (with no additional granularity). Therefore, it has been assumed that the full population of private vehicles from this dataset consisted of classes 1-2 only, while all commercial stock consisted of classes 3-8. This is a reasonable assumption since the vehicle types in classes 1-2 and 3-8 are most frequently used in private and commercial capacities, respectively. In reality, there will be some overlap which is not possible to capture in this analysis.

In lieu of Toronto level data which could provide a more granular classification of the commercial vehicles, a provincial level breakdown published by Statistics Canada[32] has been used to derive the composition of the stock. This dataset categorizes vehicles by weight brackets, rather than vehicles class. As such, vehicles weighing less than 4.5 tonnes were categorized as classes 1-2 (Cars and Light Trucks); vehicles weighing between 4.5 and 15 tonnes were mapped to classes 3-7 (Medium-Duty Trucks); while vehicles weighing more than 15 tonnes were classified as class 8 (Heavy-Duty Trucks, such as semi-trailer trucks). The breakdown of the stock at the Ontario level has been assumed to be equivalent to that of Toronto.

In addition, the vehicle stock is further split into BEVs, PHEVs and non-EVs. This was based on Ontario level data on zero emission vehicle sales from 2017 onwards, also from Statistics Canada[34]. The implicit assumption within this is that all vehicles in this dataset have remained operational until the base year. The overall process is illustrated below in Figure 45.

TransformTO data[3] was used to derive an annual growth factor for the stock of cars and light trucks, which was applied to the base year stock (derived as described above) to give an absolute total number of cars and light trucks in the city each year. The total stock growth trend does not vary between scenarios.

[31] Government of Canada, Incentives for Zero-Emissions Vehicles (iZEV), April 2022
[32] Statistics Canada, Vehicle registrations by type of vehicle, September 2020
[33] Ontario Data Catalogue, Vehicle Population Data 2016, March 2019
[34] Statistics Canada, New zero-emission vehicle registrations, January 2022

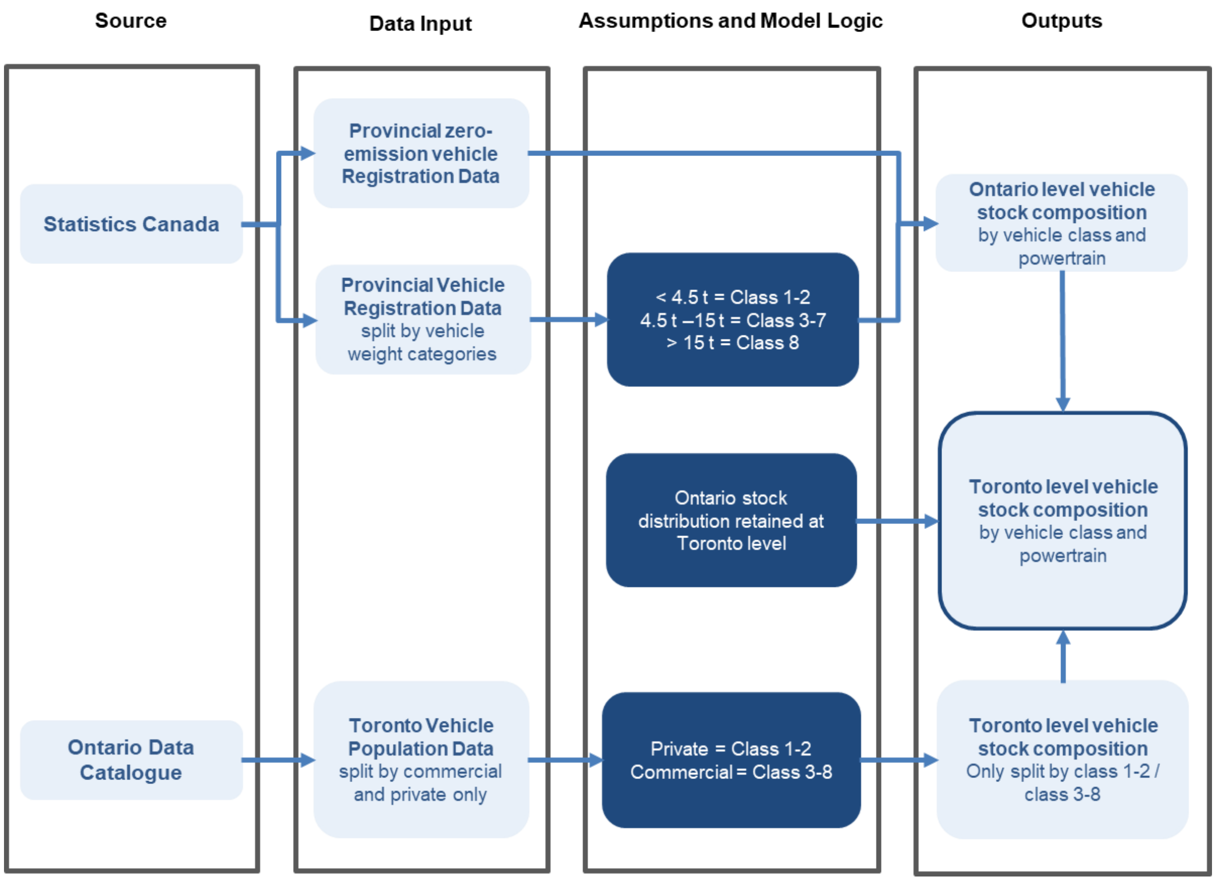


Figure 45: Methodology for deriving Toronto vehicle stock (cars and all truck types).

The bus stock in Toronto is owned and operated by the Toronto Transit Commission (TTC), who publish data regarding the makeup of their fleet including models, powertrains, age and depot locations in their annual Service Summary[35].

As of January 2022, there were 2,357 buses operational in the city, 79% of which were diesel powered. These buses span nine bus depots across Toronto. Under the assumption that all BEV and PHEV buses would charge solely at their designated depots, it is foreseeable that the peak impact of buses in specific areas of the grid could be significant, and hence is worthy of further analysis as described in Section 4.3.4.

[35] Toronto Transit Commission, Service Summary 2021, January 2022

4.3.2 Cars and Light Trucks

ECCo was used to model the development of the car stock from the common starting point derived as described in Section 4.3.1. By varying the assumptions related to policy, vehicles costs and infrastructure, three uptake scenarios for BEVs and PHEVs were developed representing a range of ambition levels. The trajectory for the total number of these types of cars in Toronto is shown below in Figure 46. The mapping of these scenarios to the overall scenario worlds is included in Table 17.

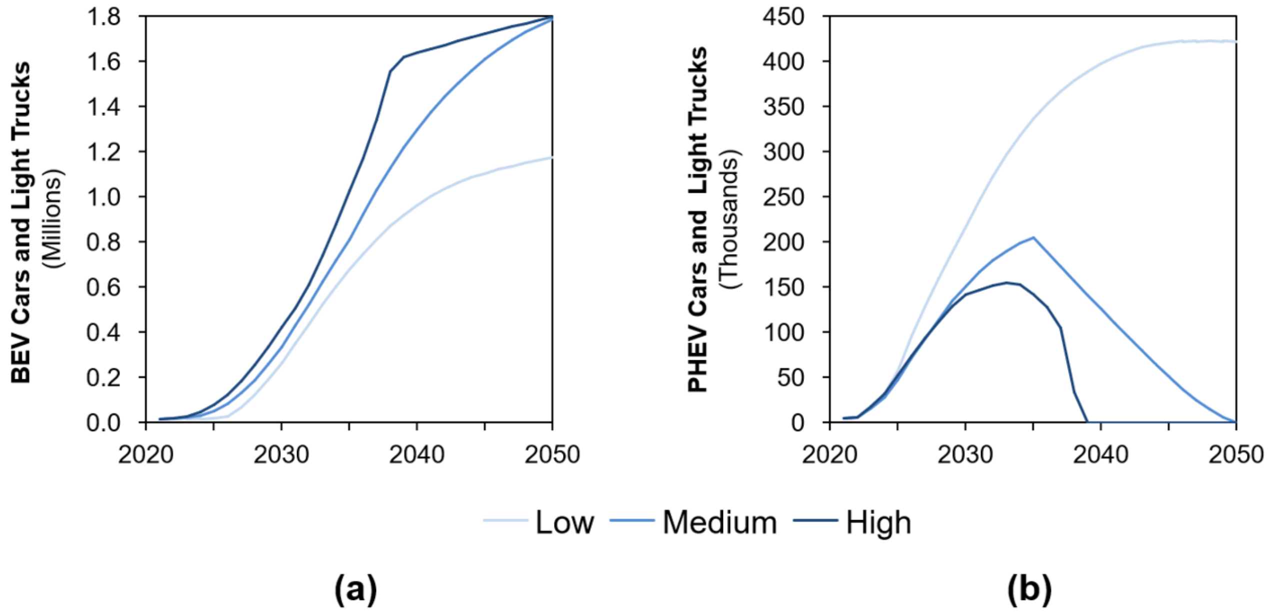


Figure 46: Comparison of Low, Medium and High stock profiles for (a) BEV and (b) PHEV cars and light trucks.

The above figure shows that the Medium and High scenarios differ primarily in the pace of their rollout of BEVs, with the Medium scenario relying more heavily on PHEVs as a transitional technology and for longer than the High scenario. However, the end states of both scenarios are comparable, with nearly 100% of the stock becoming fully electrified in both – meaning a rapid phase-out of hybrid and internal-combustion vehicles through the 2030s and 2040s.

Meanwhile, the Low scenario represents a markedly different view of the future of the transport sector. In this scenario, Toronto does not phase out hybrid or non-electric vehicles by 2050, implying a significant continued reliance on fossil fuels.

The assumptions underpinning each of the above trajectories, as well as a more detailed view of the stock breakdown in each case, are given below.

Low Scenario – Steady Progression

Table 18 describes the assumptions used in the Low scenario. A combination of low fossil fuel prices and high battery costs means that adoption of an EV would likely not be economically favourable for most consumers. Meanwhile, there is no top-down policy initiative established which could galvanize activity in the market, and as a result uptake is limited. In addition, the introduction of BEV SUVs and light trucks is delayed until 2023 and 2025, respectively, reflecting potential near-term supply constraints.

Table 18: Assumptions in Low electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; current carbon tax policies[36]
Battery Cost		BNEF 2021; "High" price until 2024[37]
Non-zero emissions vehicles (non-ZEV) ban		N/A
Accelerated Non-ZEV removal period		N/A
Delay BEV introduction until	Cars	N/A
	SUVs	2023
	Light trucks	2025

Figure 47 shows the composition of Toronto's EV stock in the Low scenario, showing the continued reliance on non-BEVs and the stalled introduction of BEV SUVs and light trucks until the mid 2020s.

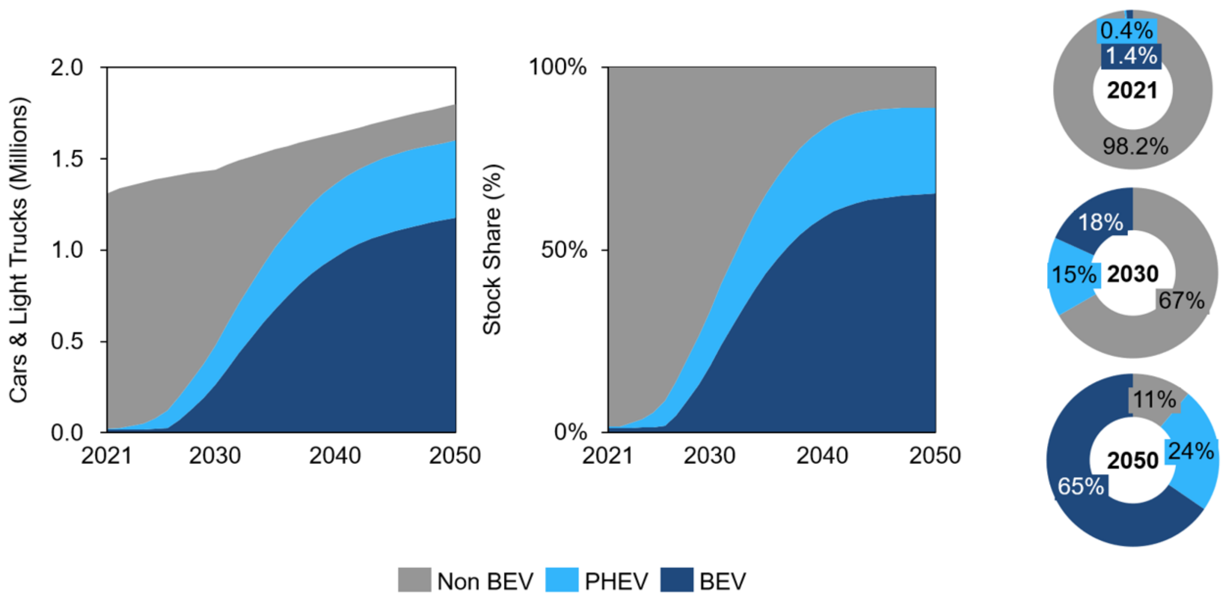


Figure 47: Low EV stock scenario – technology breakdown.

[36] Canada Energy Regulator, Canada's Energy Future, 2021
[37] Bloomberg NEF, Electric Vehicle Outlook, 2021

Medium Scenario – System Transformation & Consumer Transformation

Table 19 contains details the assumptions within the Medium scenario. As with the Low scenario, it is assumed that oil prices are low while battery prices remain high; but a non-ZEV sales ban is enacted from 2035 onwards. In addition, carbon taxation is increased from present levels, meaning the strength of the economic incentive to divest from fossil fuels increases. These factors have the effect of pushing consumers towards lower carbon options, resulting in a gradual and sustained phase out of non-BEVs. The effect of the non-ZEV phase out can be seen prominently on the PHEV trend in Figure 46b, where the curve begins to decline rapidly from 2035 onwards. Unlike the Low scenario, the Medium scenario does not delay the introduction of battery-electric SUVs and light-trucks.

Table 19: Assumptions in Medium electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021; “High” price until 2024[37]
Non-ZEV ban		2035
Accelerated Non-ZEV removal period		N/A
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto’s EV stock in the Medium scenario, showing the near complete decarbonization of this segment of transport by 2050.

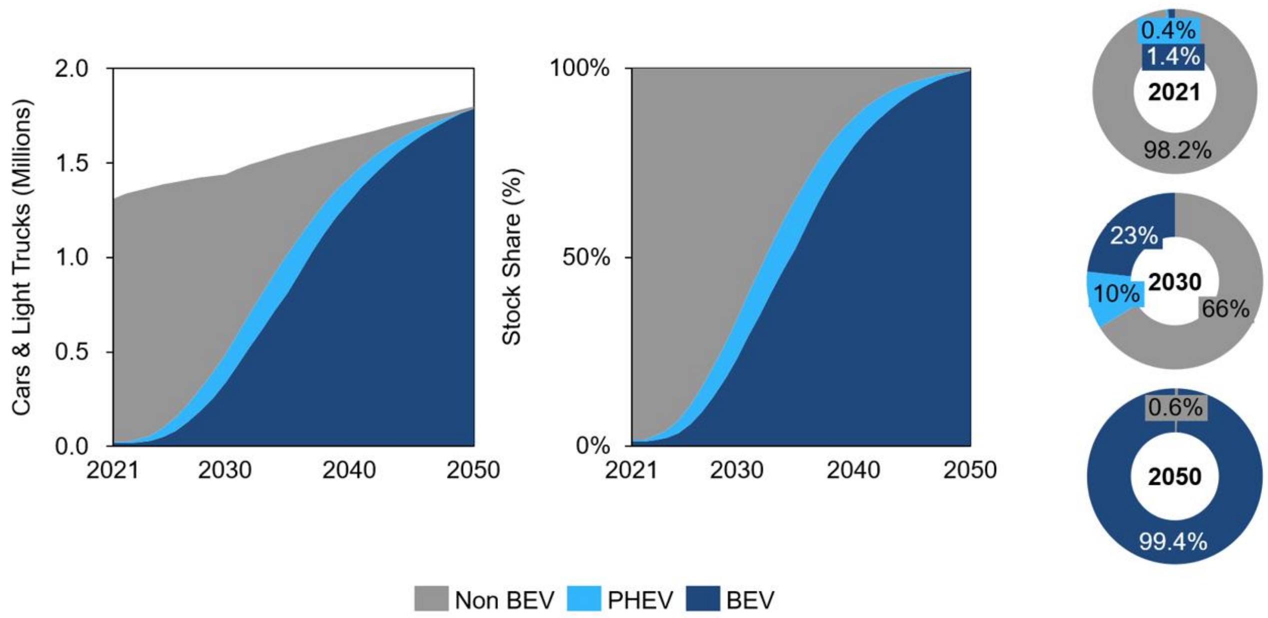


Figure 48: Medium EV stock scenario – technology breakdown.

High Scenario – Net Zero 2040

The High scenario, utilized in the Net Zero 2040 scenario world, is the most ambitious of the three scenarios. The High scenario assumes that fuel prices are high and battery costs are more favourable, meaning that consumers are more likely to decide to invest in an EV given the improved economics of this purchase decision. The carbon taxation scheme used in the Medium scenario is also retained here. Further, the non-ZEV ban applied in the Medium scenario is brought forward to 2030 (see Figure 46b) and is followed by a period of accelerated non-ZEV removal from Toronto to meet the 2040 net zero target. This could potentially be implemented via a policy mechanism such as a scrappage scheme or similar intervention. Table 20 summarizes the assumptions used in the High scenario.

Table 20: Assumptions in High electric transport uptake scenario.

Input		Assumption
Fuel Cost		High crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021[37]
Non-ZEV ban		2030
Accelerated Non-ZEV removal period		2030-40
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto's EV stock in the High scenario, showing the total decarbonization of this segment of transport by 2040.

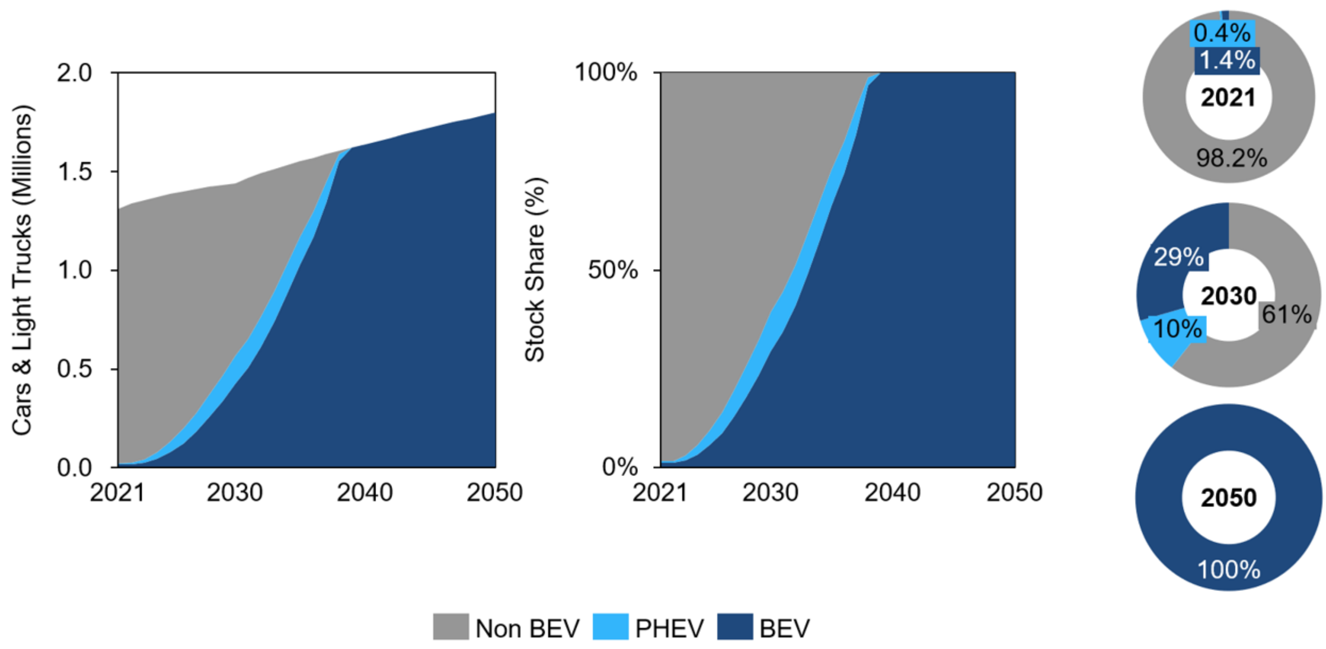


Figure 49:High EV stock scenario – technology breakdown.

4.3.3 Medium- and Heavy-Duty Trucks

The Low, Medium and High uptake scenarios for medium- and heavy-duty trucks are based on the assumptions listed below in Table 21.

Table 21: Truck uptake scenario assumptions.

Scenario	Scenario Narrative
Low	• 50% of truck sales by 2040 are ZEV • 100% of truck sales by 2050 are ZEV
Medium	• 30% of truck sales by 2030 are ZEV • 100% of truck sales by 2040 are ZEV • This aligns with Canadian Federal sales targets[38]
High	• Follows the ambitious targets of the California Air Resource Board to 2035[39] – see Figure 50 • Remaining non-ZEVs are all removed by 2040, by schemes such as scrappage bonuses.

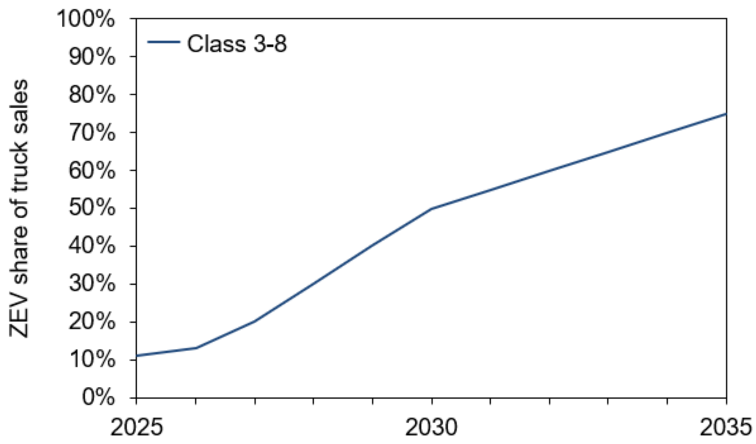


Figure 50: California Air Resource Board ZEV truck sales targets to 2035[39].

Figure 51 shows the three uptake scenarios developed using the above assumptions for class 3-7 and class 8 trucks separately. Again, these categories have been modelled separately because of their significantly different characteristics due to their weight. Principal among these differences is the energy consumed per unit of distance travelled (kWh/km). In general, the uptake of class 8 trucks (the largest commercial vehicles, such as semi-trailer trucks) leads their smaller counterparts by about two years. This is because it is assumed that the life span of such heavier vehicles is shorter and so they are replaced more frequently, meaning more of the stock is ready to be upgraded to low-carbon alternatives more quickly.

Somewhat similarly to the car and light-truck uptake trajectories described in Section 4.3.2, the Medium and High scenarios for medium and heavy trucks differ primarily in the rate at which full decarbonization of the stock is realized by 2050. Alternatively, in the Low scenario, the level of decarbonization achieved over the time horizon of this analysis is less complete. This is because in the Low scenario it takes until 2050 for all medium- and heavy-duty truck sales to be BEVs – so there is still a significant portion of the stock which consists of non-BEVs.

[38] Government of Canada, Incentives for Medium- and Heavy-Duty Zero-Emission Vehicles Program, July 2022
[39] California Air Resource Board, Medium- and Heavy-Duty ZEV requirement, 2020

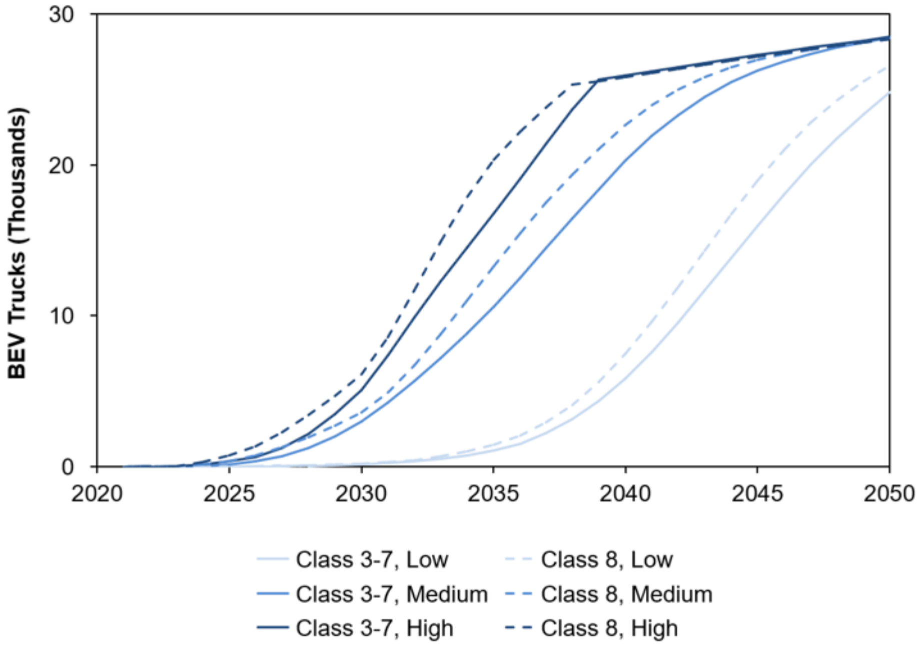


Figure 51: Stock scenarios for Class 3-7 (Medium-Duty) and Class 8 (Heavy-Duty) Trucks.

Figure 52 shows the comparative composition of the truck stock throughout the analysis for the three scenarios. The increased rate of removal of non-EVs in the High scenario is especially apparent, with 100% of medium and heavy trucks in Toronto (across all classes) switching to BEVs by 2040. In contrast, by 2050 approximately 20% of medium and heavy trucks remain non-electrified by 2050 in the low scenario.

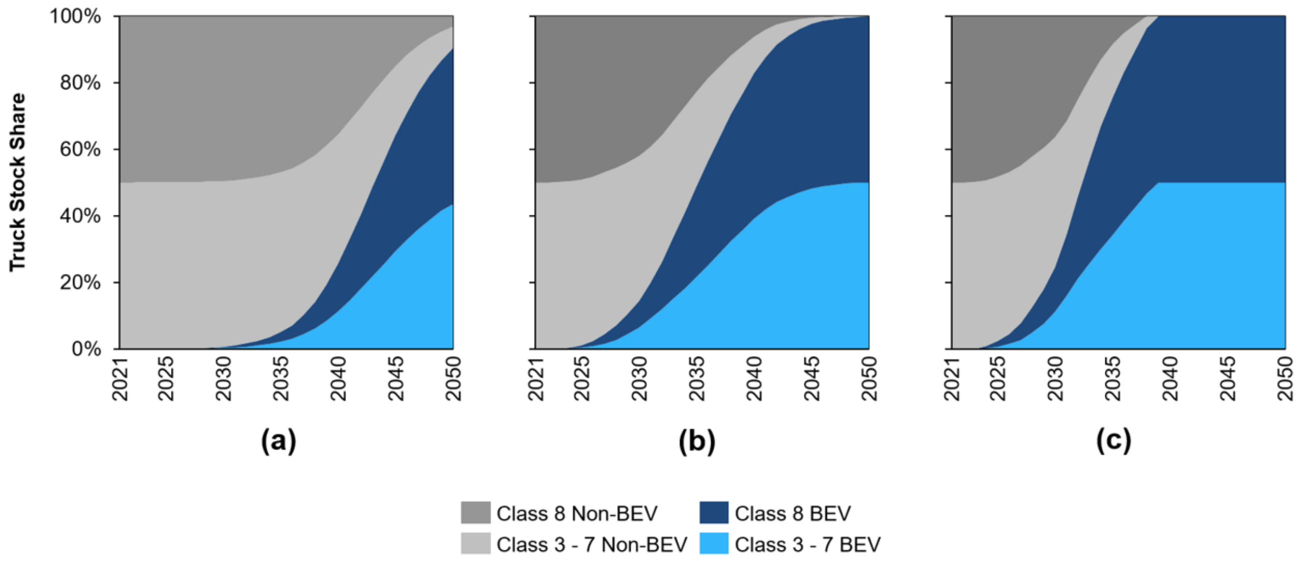


Figure 52: Truck stock split by class and powertrain in (a) Low, (b) Medium and (c) High electric truck uptake scenarios.

4.3.4 Buses

Given that the bus stock within Toronto is primarily owned and operated by a single organisation, the Toronto Transit Commission, the consumer choice approach used for other transport segments is less applicable here, so instead a simplistic representation of the TTC's decarbonization plans has been incorporated into the modelling of the bus fleet. Their current targets include the delivery of 300 BEV buses by 2025, with 100% ZEVs on the road by 2040[40]. The TTC aligned bus decarbonization phases used in this analysis can be summarized as follows:

- **Phase 1:** 20-50 BEV buses at every depot
- **Phase 2:** approximately 50% BEV rollout at every depot
- **Phase 3:** 100% BEV rollout at every depot

The date when individual depots convert their existing stock is staggered throughout each phase, and this is included in the modelling. The High scenario in this analysis aligns with the TTC's plans, while the Low and Medium scenarios include incremental delays to the completion of each phase. The assumptions applied to each scenario are set out in more detail below in Table 22. Note that in all scenarios, it is assumed that the bus stock in Toronto remains constant from the present day.

Table 22: Electric bus uptake scenario assumptions.

Decarbonization Phase	Year Phase Completed		
	Low	Medium	High (TTC compliant)
Phase 1	2029 (High + 4 years)	2027 (High + 2 years)	**2025**
Phase 2	2038 (High + 8 years)	2034 (High + 4 years)	**2030**
Phase 3	2052 (High + 15 years)	2045 (High + 8 years)	**2037**

[40] Toronto Transit Commission, TTC Green Initiatives, 2022

The number of electric buses present in Toronto under each of the above scenarios is shown below in Figure 53. The shape of the uptake curve in each scenario is similar due to the phased rollout of EVs across Toronto's buses, with the staggering between scenarios reflecting the different modelled timings for these phases.

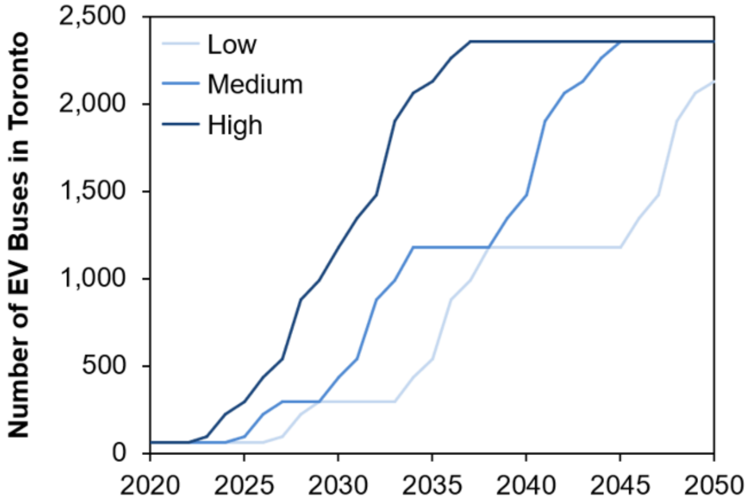


Figure 53: Electric Bus stock scenarios.

4.3.5 Rail

In Toronto, there are a number of different rail modes in operation, including:

- Subway
- Light rail
- Streetcar
- GO Transit
- Mainline Rail (VIA, Amtrak)

Of these, only the subway, light rail and streetcars are currently electrified. While there are some plans to electrify other rail modes, it is expected that these would operate on their own local network and connect to the transmission network, and so are not considered in this analysis. As of June 2022, when this analysis was undertaken, six subway and light rail expansion programs were underway or in advanced planning stages:

- Eglinton Crosstown Light Rail Transit
- Eglinton Crosstown West Extension
- Finch West Light Rail Transit
- Ontario Line
- Scarborough Subway Extension (Line 2 East extension)
- Yonge North Subway Extension (Line 1 North extension)

This also includes the closure of Line 3 Scarborough, planned for 2023. It is worth noting that after the analysis described in this report was completed, both the Waterfront Transit Network Expansion and Eglinton East Light Rail Transit projects have entered advanced planning stages. There is an opportunity for such updates to be incorporated in future iterations of this analysis. No additional significant extensions to the streetcar network are known to be planned.

To model the impacts from these extensions, a constant energy demand per km of track for each subway line has been assumed, calculated using current data on track length, energy demand and train frequency. The proposed extensions to subway lines[41] are then accounted for by multiplying the constant energy demand per km by the length of the proposed extension.

This additional demand is added to each subway line at the current grid connection and is only applied from the year of completion of expansion. This results in a single scenario, applied to all scenario worlds, with step increases in rail demand, in line with these expansions, as shown in Figure 54.

[41] The City of Toronto, Transit Expansion, June 2022

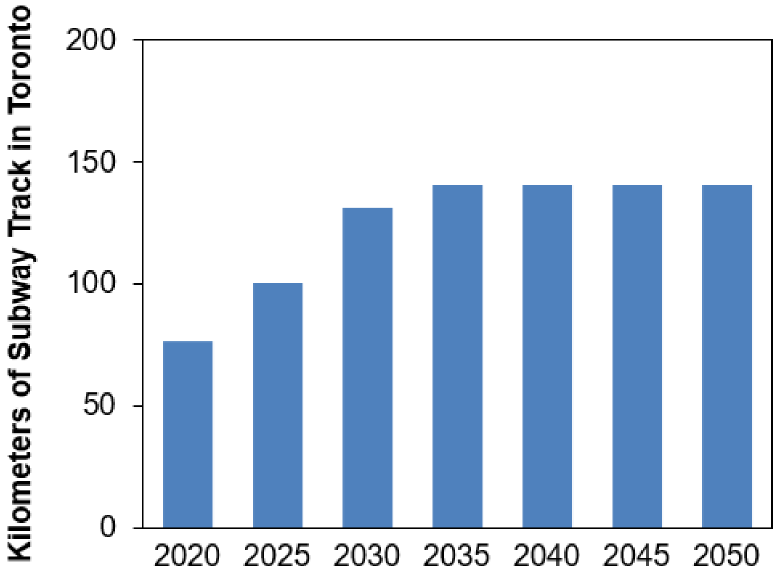


Figure 54: Total length of Subway Track in Toronto in kilometres.

4.3.6 Charging Distribution

The placement of transport demand within the modelling is challenging due to the nature of vehicles and the various ways in which they are utilized. Theoretically, any vehicle could charge at any number of points across the network as well as locations outside of the region served by Toronto Hydro. It is not enough to simply know the registered addresses of Toronto's cars; the use cases of the vehicles, the habits of their owners, and the infrastructure available for use must also be understood. The combination of these factors is referred to as "charging behaviour".

Cars and Light Trucks

The cars and light trucks represented by the Toronto-level trends presented in Section 4.3.2 are allocated to neighbourhoods as a starting point. In years preceding 2030, BEV and PHEV cars and light trucks are weighted towards neighbourhoods with greater modelled access to off-street parking, as these properties are able to install private residential charge points. This is a key driver of early EV uptake while public charging infrastructure is less mature. The distribution of homes with access to off-street charging is based on dwelling types and population density, as shown in Figure 55.

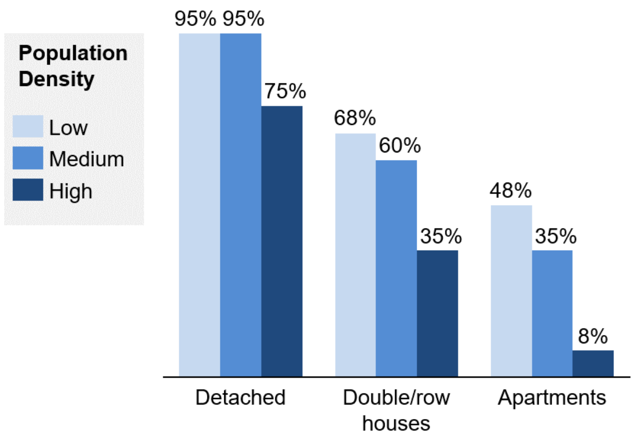


Figure 55: Level of access to off-street parking by dwelling type and population density of area[42].

After 2030, new EVs are distributed according to the current distribution of all cars across neighbourhoods, based on the assumption that access to charging will be ubiquitous across the city by that time, and a lack of private off-street charging will not impede the purchase of electrified cars and light trucks as was the case in the early years of the modelling. This then gives the distribution of EVs across the city's neighbourhoods for every modelled year. The neighbourhood an EV resides in will have a direct impact on the charging behaviour it is assumed to have in the subsequent modelling.

Cars and light trucks are assumed to charge in five distinct ways, detailed below:

- **Home charging** – owner has access to private "off-street" charging.
- **On-street residential** – owner lives in area with easy access to public charge points located by on-street parking spaces.
- **Destination** – vehicle is charged while parked at a trip destination.
- **En-route** – vehicle is charged during a journey.
- **Workplace** – owner charges their car at their workplace while at work.

Typically, most personal vehicles will be used in a variety of manners, so the customer base is further divided into eight archetypes based on the type of vehicle they own, their access to home charging and whether they commute. Within each of these eight driver types, the prominence of each of the above charging behaviours

[42] Element Energy and WSP Parsons Brinckerhoff, Plug-in electric vehicle uptake and infrastructure impacts study, 2016

varies. This breakdown is shown in Figure 56 and is derived from previous modelling work carried out by Element Energy for National Grid, which analyzed a dataset of 8.3 million charging events in the UK[43].

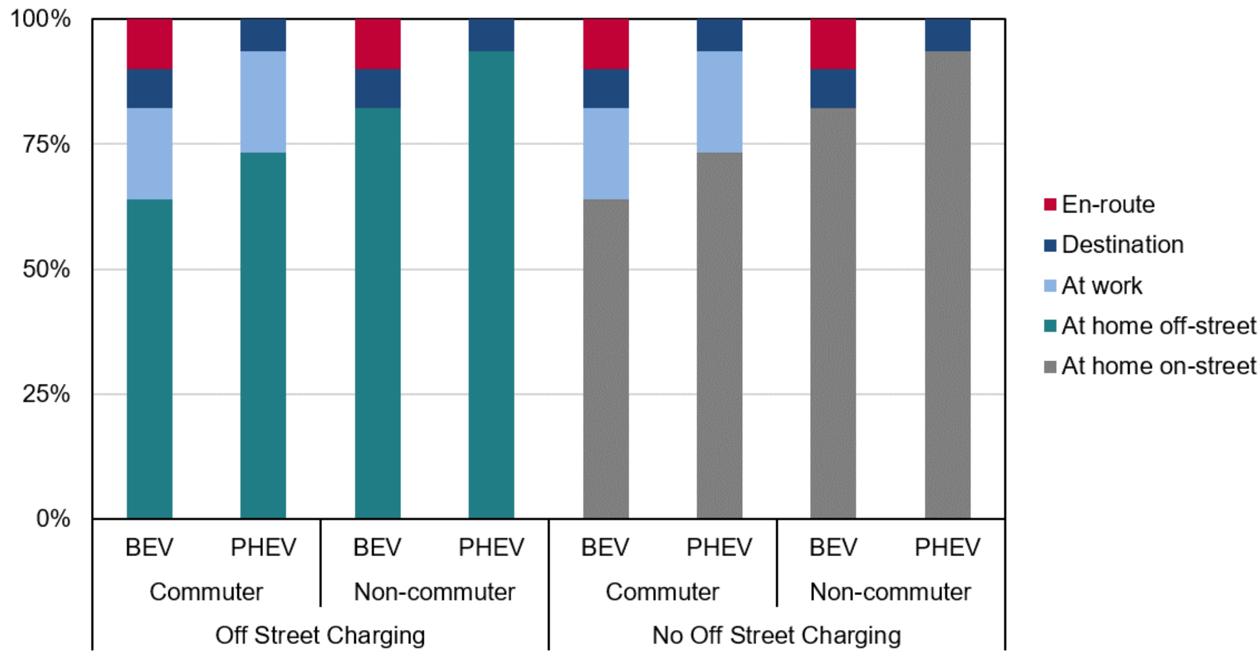


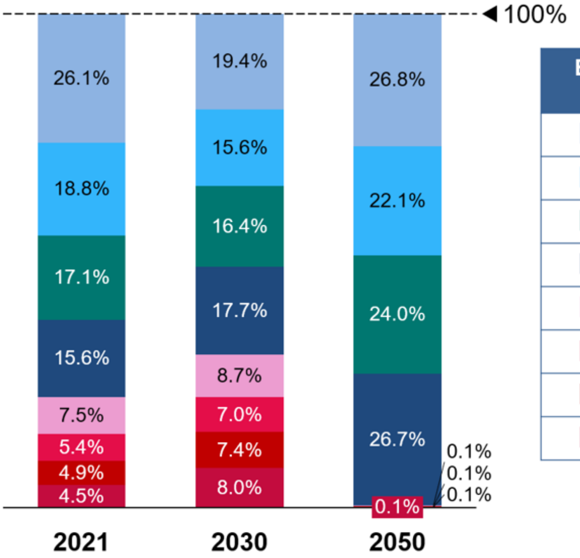
Figure 56: Prominence of charging behaviours across Toronto car and light-truck owners.

Data on the three variables defining the EV user archetypes shown in Figure 56 were used to distribute the archetypes between the neighbourhoods:

- **Powertrain proportions** (i.e. BEV / PHEV) were taken from the analysis described in Section 4.3.2. As such this parameter, and consequently the entire distribution of EV archetypes, changes between scenarios.
- **Commuting statistics** were taken from the 2021 census[44], which details the number of individuals commuting by different methods. This was combined with neighbourhood housing counts, also from the census, and data from a Toronto Metropolitan University study[45] regarding the levels of car ownership per household to give the share of cars used for commuting in each neighbourhood.
- **Home charging** was based upon access to private off-street charging and on-street public chargers, as described above (see Figure 55).

The combination of data types listed above gives a distribution of EV charging archetypes across the city which, due to the reliance on the split of BEVs and PHEVs within the vehicle stock, varies by scenario and year. Figure 57 shows the changing distribution of EV car and light truck archetypes for the Medium scenario.

[43] Element Energy, Electric Vehicle Charging Behaviour Study, 2019
[44] Statistics Canada, 2021 Census of population, 2021
[45] Toronto Metropolitan University, Household car ownership, 2018



EV Archetype	Powertrain	Off-Street Charging	Commuter
1	BEV	✓	✓
2	BEV	✓	✗
3	BEV	✗	✓
4	BEV	✗	✗
5	PHEV	✓	✓
6	PHEV	✓	✗
7	PHEV	✗	✓
8	PHEV	✗	✗

Figure 57: Changing EV charging archetype distribution at Toronto Level, Medium stock scenario

Since the EV archetype distribution varies by scenario, and because of the reliance of each archetype on different charging behaviours (as shown in Figure 56Figure 56), the physical positioning on the network of the loads due to EVs also changes between the uptake scenarios.

The location of charging events across the city (i.e. where each of the above archetypes charge their vehicles for the range of charging behaviours) was derived as follows:

- **Home charging** is consistent with the distribution of EV owners with access to off and on-street parking used to formulate the EV archetype distribution described above (Figure 58a).
- **En-route charging** is localized to existing gas stations which are within 500m of an expressway (Figure 58b). Other existing gas stations are not explicitly allocated any charging demand in the modelling. This is because the assumed prevalence of other charging types means that most drivers can charge at home or their destination for most journeys, while those on longer journeys can make use of stations near expressways.
- **Destination** and **Workplace** charging are localized to parking lots dependent on zoning data[46] (Table 23, Figure 58c, and Figure 58d).
- **Workplace** charging also considers demand from commuters who reside outside of Toronto, but commute into the city. It is assumed that en-route and destination charging events from non-Toronto residents evens out with Toronto residents who sometimes charge their cars outside of the city.

Table 23: Assumed mapping of parking lot zoning types to car and light truck charging locations.

Parking Lot Zoning Type	Destination	Workplace
Open Space	✓	✗
Commercial Residential Mixed Usage	✓	✓
Residential	✗	✗
Utility and Transportation	✓	✓
Heavy Industry	✗	✓
Employment	✗	✓
Business Park	✓	✓
Institutional	✓	✓
Commercial	✓	✓
“Other”	✓	✓

[46] City of Toronto Open Data Portal, Land use zoning by-law, 2022

Maps showing the modelled distribution of these charging locations throughout the city are shown below in Figure 58.

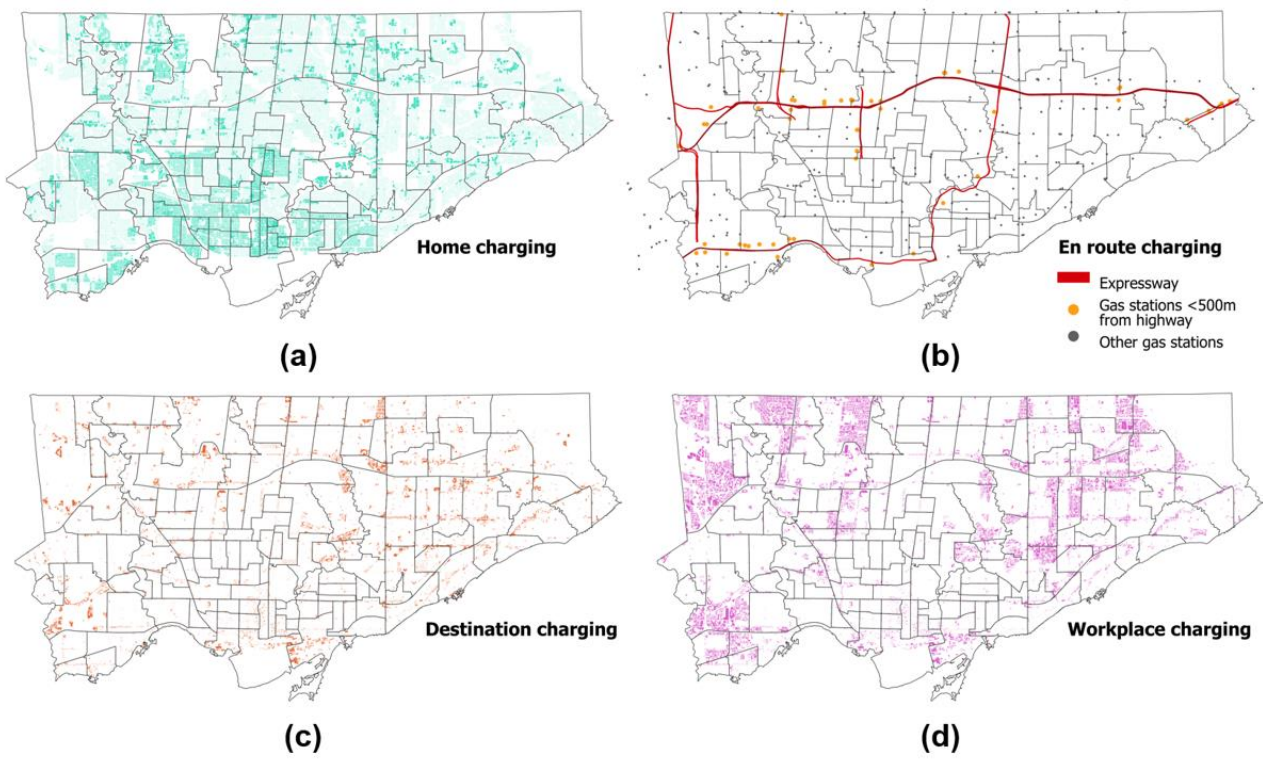


Figure 58: Charging type distributions for cars and light trucks.
(a) Home charging; (b) En-route charging; (c) Destination charging; (d) Workplace Charging.

Buses, Medium- and Heavy-Duty Trucks

As previously described in Sections 4.3.1 and 4.3.3, it is assumed that all medium- and heavy-duty trucks are used for commercial purposes only, in the same way that cars and light-trucks have been assumed to be for personal use. The modelling of medium- and heavy-duty trucks is split by weight class due to the differing energy requirements of each. In addition, different average journey lengths are assumed for each weight class to reflect the different usage patterns of medium sized trucks as compared with larger vehicles like semi-trailer trucks. Finally, all buses are treated as equal in the modelling.

As with destination and workplace charging, commercial vehicle depot charging is positioned according to parking lot zoning data[46]. The mapping used to locate charging depots for the commercial medium- and heavy-duty truck stock is shown below in Table 24. Based on research by Element Energy of truck driving behaviours across the UK[47], trucks are assumed to be able to do most of their charging at their home depot or at warehouses on their scheduled route. Longer distance trucking journeys likely require some en-route charging, however Toronto is assumed to be primarily a journey end or starting point for these trucks, so there is expected to be little en-route truck charging demand which affects Toronto Hydro's network. Therefore, all medium- and heavy-duty trucks are assumed to charge at their designated depot.

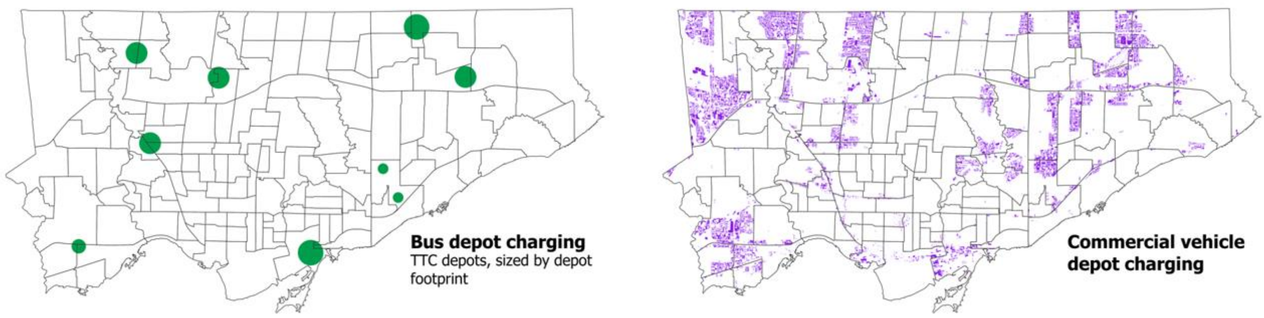
[47] Element Energy for Transport & Environment, Battery electric HGV adoption in the UK: barriers and opportunities, November 2022

Table 24: Assumed mapping of parking lot zoning types to medium- and heavy-duty truck charging locations.

Parking Lot Zoning Type	Truck Depot
Open Space	✗
Commercial Residential Mixed Usage	✗
Residential	✗
Utility and Transportation	✓
Heavy Industry	✓
Employment	✓
Business Park	✓
Institutional	✗
Commercial	✗
"Other"	✓

The current bus depots used by the TTC are assumed in the modelling of future bus stock (see Section 4.3.4) to remain in use until 2050, with no new additions. As such, all bus charging events are assumed to occur at the locations of these depots. The buses in the stock model are also designated to a specific depot, at which they are assumed to always charge.

The distributions of the charging locations for buses, medium- and heavy-duty trucks are shown below in Figure 59.



(a) (b)

Figure 59: Charging distributions used for (a) buses and (b) medium- and heavy-duty trucks.

4.3.7 Smart Charging and Vehicle-to-Grid

With the push to electrify transport, Canadian local distribution companies (LDCs) have recently begun actively investigating the charging behaviour of EV users and the potential uptake of flexible demand-side technologies such as smart charging and "vehicle-to-grid" (V2G). However, most of these studies are ongoing and thus results are not yet available. Table 25 lists the EV charging studies explored for this work.

Table 25: Canadian LDC EV charging studies.

LDC	Description of study	Status
Toronto Hydro	EV smart charging pilot	Recruitment phase
Toronto Hydro	Utility-controlled smart charging study	Completed
Hydro One/ Peak Power	Vehicle-to-home (V2H) pilot program	Ongoing
Nova Scotia Power	Utility-controlled smart charging pilot	Ongoing
ENMAX	Smart charging study looking at demand shift potential based on incentives	Ongoing

Given the ongoing nature of these studies, there is currently limited data available on the potential of V2G technology in Canada. Subsequently, internal modelling was used to determine uptake scenarios for V2G technology. These scenarios were formulated to reflect likely levels of penetration of V2G and are conservative due to high costs of bi-directional chargers and current limitations around the business case for this technology[48].

With regards to smart charging, a few sources were used for data on the smart charging landscape within Canada and Toronto. The utility-controlled study performed by Toronto Hydro[49] had valuable baseline data on the charging behaviour of Toronto residents. Additionally, an analysis of the Plug N Drive survey in Toronto[50] identified that 83% of EV users "relied on overnight charging all of the time or some of the time". The data from these two sources, while specific to Toronto, doesn't map directly onto the smart vs. non-smart charging regimes required for this component of the analysis and were therefore used primarily as a sense check against an Ontario-level study performed by FleetCarma. The "Charge the North" study by FleetCarma[51] identified Ontario-level proportions of total charging energy by rate period. In the report, charging during the off-peak period was considered "smart"; in Ontario, off-peak charging was found to account for 85% of charging, which is close to the value reported in the Plug N Drive survey and is also close to the current ToU tariff penetration in Toronto (84%).

As the smart charging proportion matches closely with the current ToU tariff penetration, the Medium scenario envisions no change in smart charging activity, in line with the modelled ToU behaviour. The High scenario is a more ambitious view of the future, where the new overnight tariff structure proposed by the OEB, which targets EV users, is assumed to drive smart charging participation, reaching 100% in 2030. Finally, in the Low scenario, an equal but opposite rate of change of smart charging penetration as the High scenario is assumed, with participation decreasing to 70% in 2030, after which equilibrium is maintained. The scenarios developed, which outline the proportion of charging which is unmanaged, smart, or V2G, are shown in Figure 60. The Low scenario sees no adoption of V2G charging at any point, while there is a gradual introduction of V2G from 2030 onwards in the Medium scenario. In the highest ambition scenario, unmanaged charging is fully and

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[48] Element Energy, V2GB – Vehicle to Grid Britain Requirements for market scale-up (WP4), June 2019
[49] Bauman, J. et. al., Residential Smart-Charging Pilot Program in Toronto: Results of a Utility Controlled Charging Pilot, June 2016
[50] IAEE, Driver Experiences with Electric Vehicle Infrastructure in Ontario, Canada and the Implications for Future Policy Support, Fourth Quarter 2020
[51] FleetCarma, Charge the North, 2019

rapidly phased out, and V2G uptake begins immediately from the base year. From 2030 onwards all EVs are charging in a flexible manner in the High scenario.

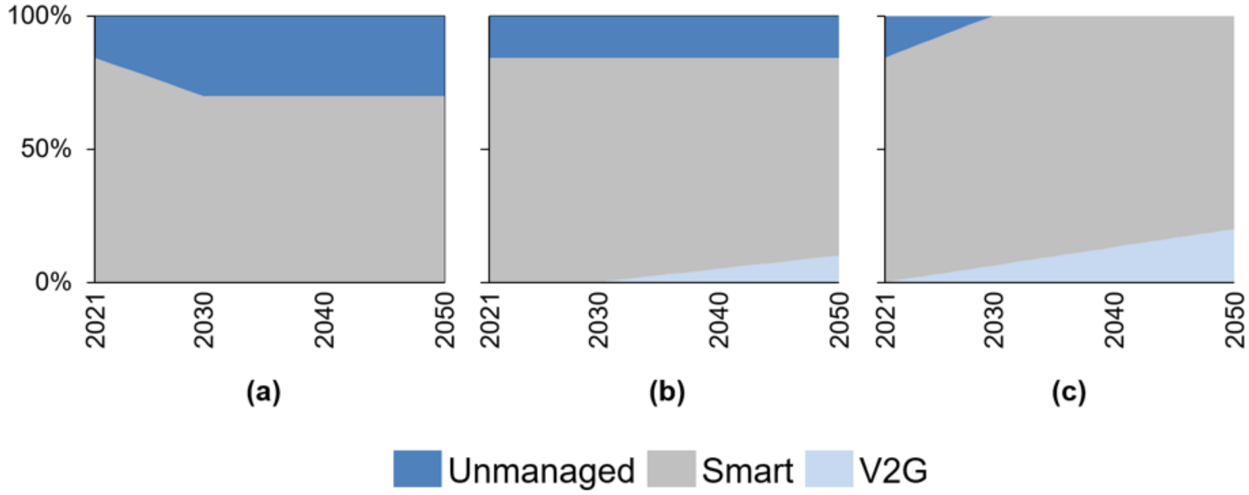


Figure 60: Proportion of EV drivers participating in various charging types, for the (a) Low, (b) Medium, and (c) High scenarios.

4.4 Electricity Generation

A range of generation technologies that can connect to the distribution network have been considered in the analysis. As with demand, three to four future uptake scenarios (e.g., Low, Medium, High, and Very High) have been developed for each technology, which have then been assigned to the four scenario worlds according to how they align with their respective narratives. The full mapping of generation uptake scenarios to the scenario worlds is shown in Table 26.

Table 26: Distributed generation technology uptake scenario mapping.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Rooftop solar PV*	Low	Medium	High	Low	Very High	Low
Ground-mount solar PV*	Low	Medium	High	Low	High	Low
Wind	Low	Low	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Non-renewables	High	Low	Medium	High	Low	High

* Rooftop solar PV is defined as installations of capacity less than or equal to 250 kW and ground-mount solar PV refers to installations larger than 250 kW.

4.4.1 Modelling Approach

The approach used for modelling the uptake of distributed generation consists of three steps, as outlined in Figure 61. Existing generation is used as a baseline value and a pipeline is added to this value over a pre-defined number of years. After this point, uptake projections follow the long-term pathways that are generated based upon a range of methods, including consumer choice modelling, external datasets, and stakeholder engagement.

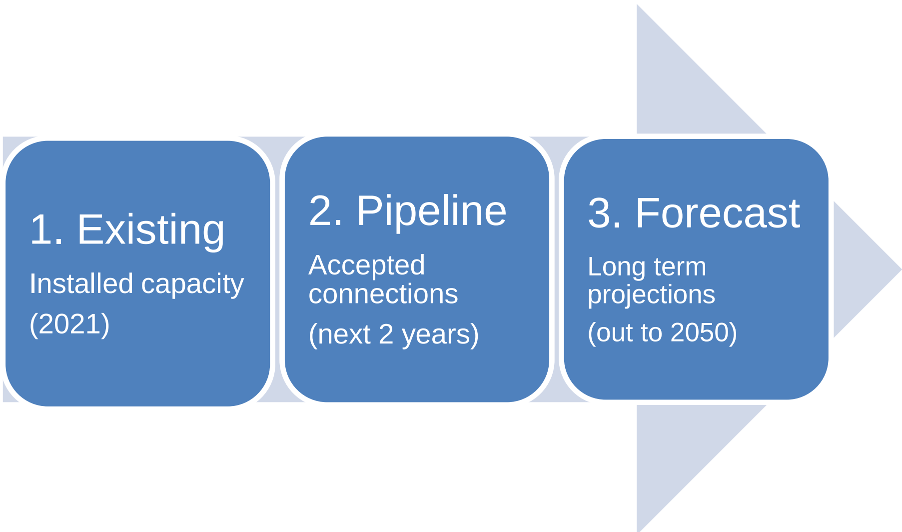


Figure 61: Pathway for modelling distributed generation.

Existing generation capacity was drawn from data provided by Toronto Hydro, which was checked against other sources such as the IESO Active Contracted Generation List[52]. The existing generation baseline included everything connected by the end of 2021.

[52] IESO, Active Generation Contract List, June 2021

The pipeline for all generation and storage was defined as the two years after the baseline, that is 2022 and 2023. The proportion of pipeline connections projected to connect varied by scenario and by size, as detailed in Table 27. These definitions reflect Toronto Hydro's understanding of how pipeline generation typically connects, based upon historic trends.

Table 27: Proportions of pipeline generation capacity that connects in each scenario.

Pipeline Generator Size	Low	Medium	High
< 1MW	40%	60%	100%
≥ 1MW	60%	90%	100%

The method used for developing long-term projections varied by generation technology and is summarized in Table 28. Solar PV uptake projections were developed using Element Energy's in-house consumer choice model, whilst wind projections were developed through consultation with Toronto Hydro stakeholders. Non-renewables uptake projections were based upon projections from the TransformTO dataset, and biogas projections were based upon varying levels of fuel switching as non-renewables are phased out. Note that there was no pipeline generation for wind or biogas. Existing and pipeline generation is distributed to transformer station buses according to the current or expected locations of deployment, while projected generation is distributed across the region according to various methodologies which are specific to each technology.

Table 28: Modelling method for distributed generation technologies.

Technology	Renewable	Pipeline duration	Long-term projection
Solar PV	✓	2 years	Element Energy in-house modelling and TransformTO proejctions
Wind	✓	No pipeline	Informed by consultation with Toronto Hydro Stakeholders
Biogas	✓	No pipeline	Informed by TransformTO non-renewables projections
Non-renewables	✗	2 years	Data drawn from TransformTO

The total level of generation in Toronto Hydro's network area is show in Figure 62, illustrating capacity across all four scenario worlds in 2021, 2030, and 2050. This figure demonstrates that, based upon the modelling, solar PV is likely to be the dominant distributed generation technology in Toronto Hydro's region in a decarbonized future. This is particularly pronounced in the Net Zero 2040 scenario world, where projections have been aligned with the Net Zero 2040 projections in TransformTO. All three net zero compliant scenario worlds phase out non-renewable generation technologies by 2050 and rely strongly on solar generation, whereas Steady Progression continues to rely on electricity from gas and diesel out to 2050. In the following sections, these results are discussed in more detail. Section 4.4.2 explores the modelling of solar PV, the largest single contributing factor to the generation mix in 2050 for all four scenario worlds.

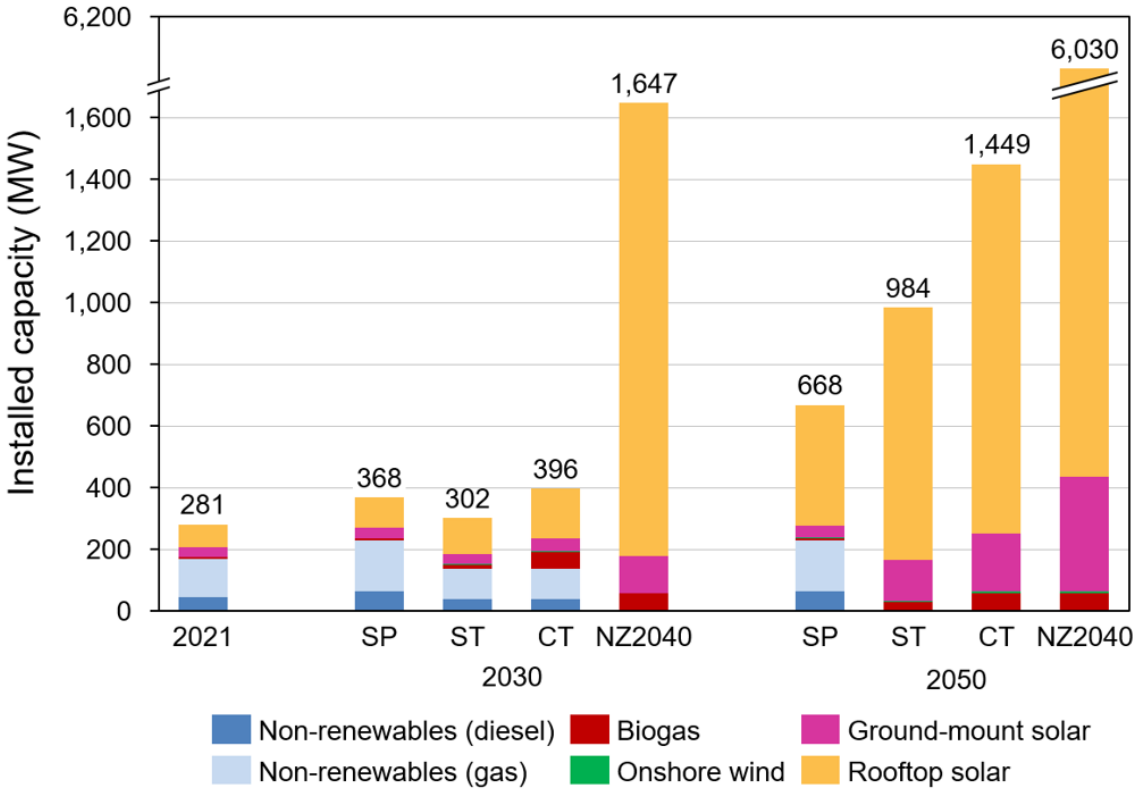


Figure 62: Capacity of distributed generation installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.4.2 Solar Photovoltaics

Solar PV uptake scenarios were derived using a consumer choice model for rooftop (≤250 kW) and large-scale (>250 kW) generation uptake. This uptake model accounts for variation in solar PV installation properties and economics by modelling different size bands. The size bands have been associated with typical installation types, as summarized in Table 29 below, and different installation costs applied to each band.

Table 29: Classification of solar PV size bands.

Solar PV Size Bracket (kW)	Classification
≤ 250	Rooftop
> 250	Ground-mounted

Rooftop Solar PV (≤ 250kW)

Small-scale solar PV is defined as being those installations that occur on rooftops of domestic and I&C buildings (Table 29Table 29). Figure 63 shows that the solar uptake in the Low, Medium and High scenarios, which are developed using Element Energy's consumer choice model, range between 400 MW and 1,200MW by 2050. These increase from a baseline of 75 MW in 2021 and a maximum pipeline of 3.4 MW. These pathways are developed by considering the economic case for purchasing solar panels from a consumer perspective. Post-pipeline uptake to 2050 is driven in large part by capital cost reductions[1,53], while increases in electricity prices[54] and net metering revenues[55] further incentivize uptake in future years. Rooftop solar is distributed across Toronto using customer counts in each neighbourhood and terminal station service area.

Future solar generation is calibrated using historic uptake data[52] and by considering the business case of purchasing solar panels in previous years[56]. Using this information, the model develops calibration coefficients that are used to adjust future solar generation projections.

In the Low scenario, it is assumed that the energy system will continue to rely on gas- and diesel-fired generation in 2050 and less emphasis is placed on incentives for the uptake of renewable generation. Conversely, in the High scenario, uptake is based upon the lowest projections of capital installation costs, higher revenues from net metering and avoidance of electricity charges. In the Very High scenario, projections are aligned with those from TransformTO[3], adjusted to the baseline and pipeline data provided by Toronto Hydro, resulting in an uptake of 5,600MW of rooftop solar generation installed by 2050. The Very High scenario is based on the technical potential of solar generation in Toronto and hence represents an upper bound where 100% of suitable buildings install solar PV.

[53] NREL, Solar Futures Study, 2021
[54] Higher electricity prices can result in higher uptake since consumers that install a solar PV system can avoid paying these high prices for their electricity to some extent and can also potentially achieve higher revenues when selling their generation back to the grid.
[55] OEB, Electricity Rates, 2022
[56] IESO, microFiT Program, 2022

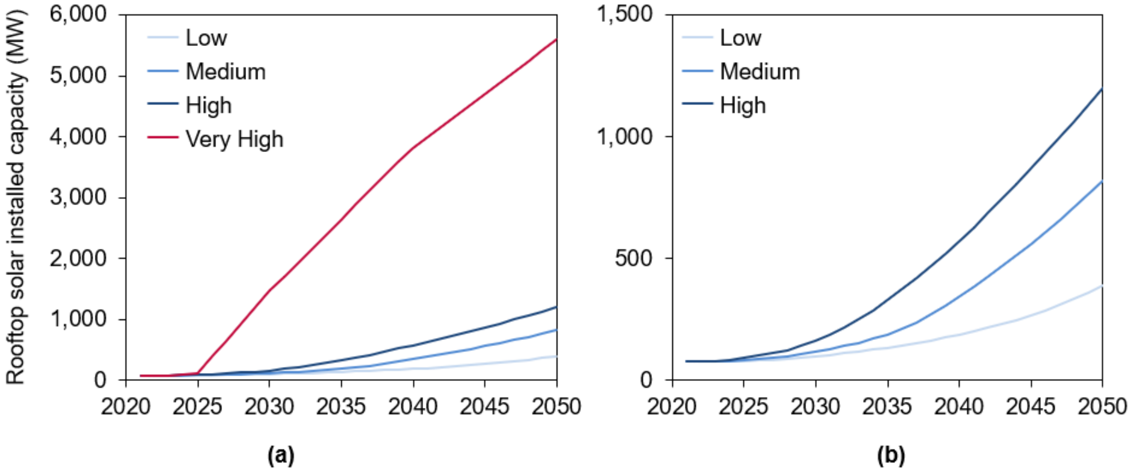


Figure 63: Installed capacity of rooftop solar PV in Toronto Hydro's network area out to 2050. (a) including "Very High" scenario, used in NZ40; (b) excluding "Very High" Scenario.

Ground-Mount Solar PV (>250kW)

Ground-mount solar PV is defined as those installations that have a capacity greater than 250kW and are likely to be deployed in parking lots or green space. Figure 64 shows that uptake in 2050 ranges between 39 MW and 371 MW across the Low to Very High scenarios. The overall approach is the same as that taken for Rooftop solar PV with the Low to High scenarios generated using Element Energy's consumer choice model and the Very High scenario aligned with the pathway in TransformTO. Ground-mount solar PV relies on the same drivers as for small solar PV but also draws some benefits from capacity market revenues[57]. A cost uplift has also been applied to account for additional costs associated with finding suitable areas to site generation. Where rooftop solar PV is distributed according to customer counts, ground-mount solar PV is distributed to available space in parking lots[58], in line with Transform TO assumptions on ground mounted PV deployment.

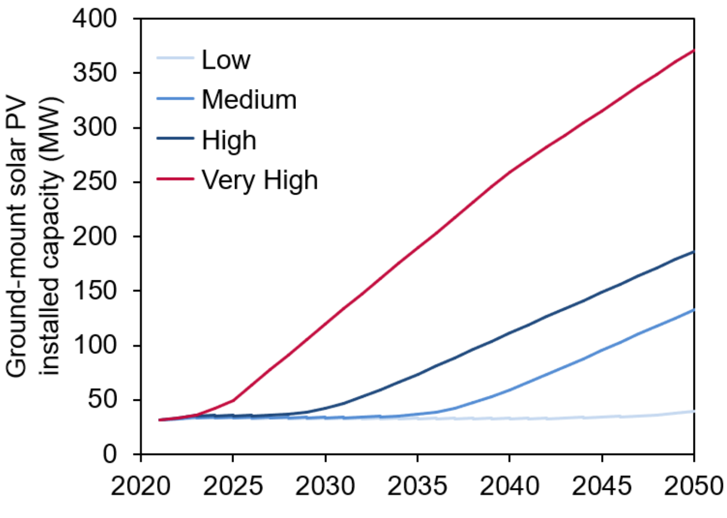


Figure 64: Installed capacity of ground-mount solar PV in Toronto Hydro's network area out to 2050.

[57] IESO Capacity Auction, 2022
[58] City of Toronto, Physical area of parking lots, 2019

4.4.3 Onshore Wind

Onshore wind projections were developed through consultation with key stakeholders within Toronto Hydro to establish a consensus on the expected range of uptake that could occur across the different scenario worlds. Due to there being very few historic onshore wind installations in Toronto (only four installations, the largest of which took place when no feed-in tariffs were in place), a meaningful calibration of the consumer choice modelling for onshore wind could not be conducted. The consultation process with Toronto Hydro stakeholders resulted in scenarios ranging between 0.76 MW and 8.3 MW of installed capacity by 2050. Projections are assumed to ramp up linearly after the pipeline years; however, the accepted generation data provided by Toronto Hydro does not include any onshore wind and so there is no projected pipeline capacity. Future uptake of onshore wind was distributed based upon greenspace in neighbourhoods adjacent to Lake Ontario which involved spreading uptake across this area rather than attempting to model individual turbine locations.

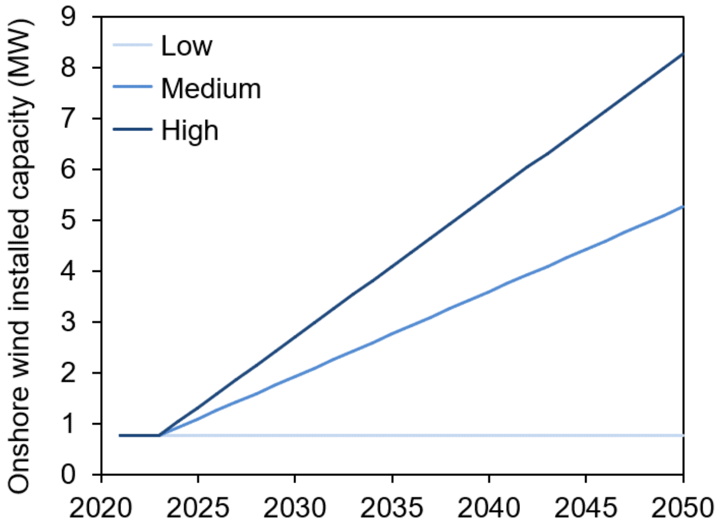


Figure 65: Installed capacity of onshore wind in Toronto Hydro's network area out to 2050.

4.4.4 Non-Renewables

Non-renewable generation considers all gas and diesel generators in Toronto, which currently make up the largest share of distributed generation. In the Low scenario, it is assumed that all non-renewable generation is phased out by 2030. This is consistent with the trajectories mapped out in TransformTO and is in line with ambitions of various municipalities in Ontario, including the City of Toronto[59]. The TransformTO trajectory for natural gas has been applied to all non-renewable generation, as TransformTO does not have specific categories for local CHP or diesel generation. This trajectory was scaled such that it aligns with existing generation connected to the Toronto Hydro network. In the Medium scenario, this trajectory is extended to 2050, assuming that the phase out follows the same pathway but at a slower rate. In the High scenario it is assumed that after pipeline generation is added, there is no phase-out of non-renewable generation and no new installations are added.

[59] Ontario Clean Air Alliance, Ontario Municipalities that have endorsed gas power phase-out, March 2021

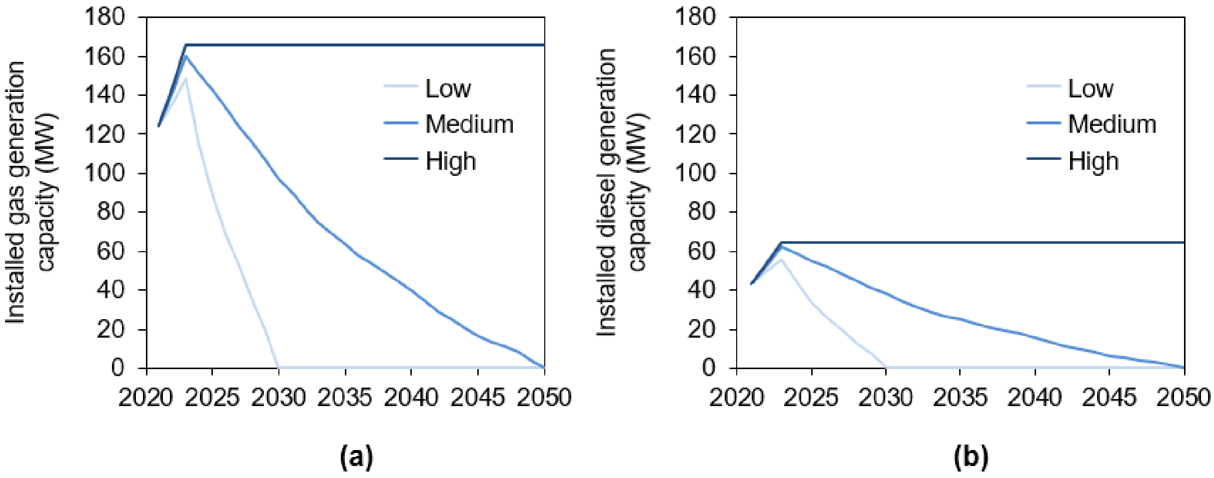


Figure 66: Projected installed capacity of (a) natural gas generation and (b) diesel generation.

4.4.5 Biogas

Biogas is assumed to act as a transition technology for natural gas and can be used in a variety of applications, including electricity generation. The High scenario for biogas pairs with the Low non-renewable scenario and is created by assuming 25% of phased-out non-renewable generation capacity is replaced by biogas. The Medium biogas scenario pairs with the Medium non-renewable scenario and assumes 10% of phased-out non-renewable generation is replaced by biogas. The Low scenario is a continuation of historic trends. In all biogas scenarios, there is no additional capacity in the pipeline. Since biogas is assumed to replace non-renewables, geo-distribution for biogas generation is based upon the historic distribution of gas generation.

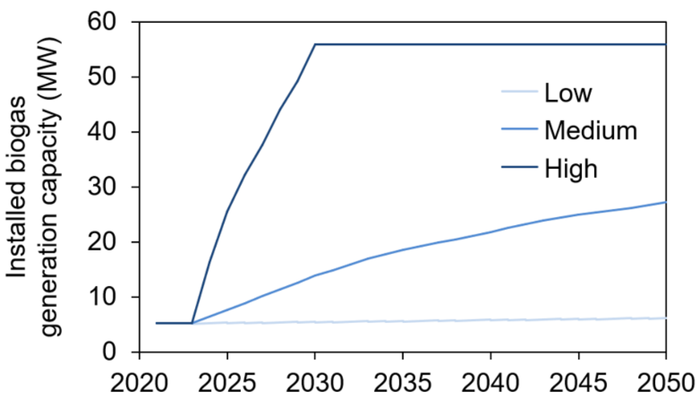


Figure 67: Installed capacity of biogas for electricity generation in Toronto Hydro's network area out to 2050.

4.5 Energy Storage

The uptake of two different battery storage use cases was modelled in this project. For each use case, three to four future uptake scenarios were developed and assigned them to the four scenario worlds as outlined in Table 30.

Table 30: Battery storage types modelled and their mapping to scenario worlds.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

Grid-scale storage is assumed to be driven by network-level needs for energy storage and is therefore not modelled within the Future Energy Scenarios. This approach considers grid-scale storage to be a solution which would be deployed in response to needs identified by Toronto Hydro. Storage could also be developed by the IESO in response to overall system needs. However, it is likely that this would not be connected to Toronto Hydro's network, but rather in other areas in Ontario where land is cheaper and/or connected to the transmission network.

The uptake of battery storage for each use case is modelled based on a specific set of assumptions around the associated business case for those particular battery storage installations. Table 31 shows the different use cases, the relevant business case considered, and the modelling method used.

Table 31: Modelled battery storage use cases and the corresponding business cases and modelling methods.

Technology use case	Modelled business case	Modelling method
Domestic battery storage	**Coupled to solar PV** Maximize own use	Consumer choice modelling coupled with domestic solar PV uptake modelling
I&C behind-the-meter battery storage	**Arbitrage and system balancing** e.g., electricity price arbitrage, the Industrial Conservation Initiative (ICI), Operating reserve	Consumer choice modelling

The baseline and pipeline data for behind-the-meter storage, both domestic and industrial and commercial, was from the data provided by Toronto Hydro. The pipeline calculations follow the same methodology across the scenarios as used for generation (Table 27Table 27). Figure 68 shows the overall level of battery storage capacity installed across Toronto Hydro's region in all four scenario worlds in 2030 and 2050. Consumer Transformation and Net Zero 2040 show the highest battery storage uptake since these scenario worlds are assumed to have the greatest need for storage to help offset grid demands caused by high electrification and rapid uptake of low carbon technologies. In these scenarios, battery prices are assumed to follow their lowest cost trajectory, and higher revenue streams for both domestic and I&C behind-the-meter storage are assumed. For domestic storage, this corresponds to higher income from grid-export and higher savings from self-consumption, while I&C storage draws from a larger revenue stack which includes the Industrial Conservation Initiative (ICI), price arbitrage, and operating reserve. System Transformation sees less battery storage uptake due to lower assumed levels of electrification. Steady Progression sees the least uptake as the scenario world with the lowest levels of ambition and decarbonization. In the following sections, the modelling approaches and assumptions for battery storage are outlined and the results are discussed in more detail.

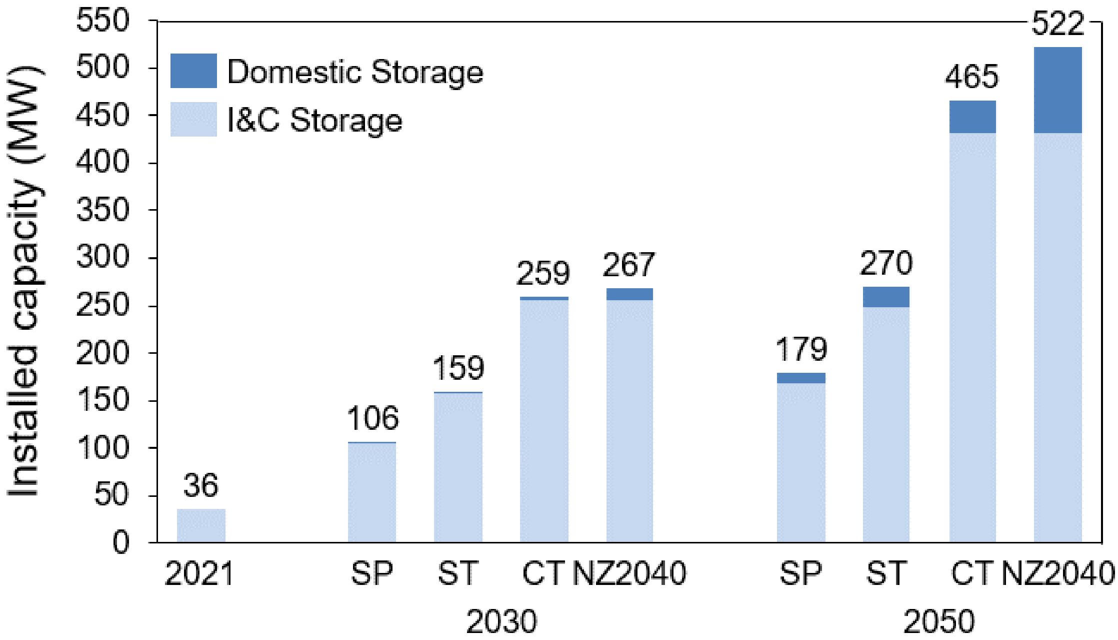


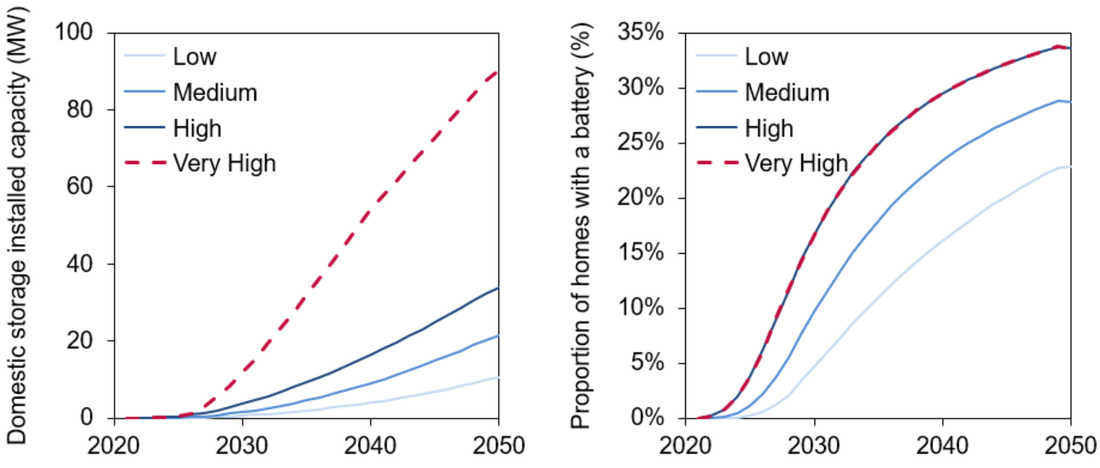
Figure 68: Capacity of battery storage installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.5.1 Domestic Battery Storage

The business case for domestic storage is coupled to the uptake of solar generation that is expected to connect at domestic residences (≤10 kW). Uptake scenarios for domestic storage are derived using a module of the solar generation consumer choice model. This considers the purchase decision for a solar PV system with a battery as well as retrofitting a battery to an existing solar PV installation which is less than five years old. Therefore, scenarios for domestic battery storage differ according to the underlying scenario for solar PV (since the batteries are added to households with solar PV) and by the battery cost projection used in each case. An average battery power is considered to be half the solar panel capacity, with a two-hour storage capacity, and account for variances in battery pack costs[60,61], installation costs, and product availability across the three scenarios. If the battery option is chosen, the owner is assumed to use it primarily to maximize their own consumption of their solar PV generated electricity.

The results from this modelling (Figure 69Figure 69) indicate that between 23% and 34% of all domestic solar PV owners in Toronto Hydro's network area may install a battery by 2050. While the proportion of solar PV owners with batteries is assumed to be the same in the High and Very High scenarios, the absolute capacity is much greater in the Very High scenario due to the substantially larger level of solar generation uptake. Therefore, the range of uptake in the Low to High scenarios is between 11MW and 34MW, while the Very High scenario sees an uptake of 90MW. Baseline and pipeline capacity for domestic battery storage are both assumed to be zero.

[60] NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update, June 2021
[61] KPMG, Development of decentralized energy and storage systems in the UK, October 2016



(a) **(b)**

Figure 69: (a) installed capacity of domestic storage in Toronto Hydro's network area out to 2050, (b) proportion of all domestic customers who install a battery.

4.5.2 Industrial and Commercial Battery Storage

Uptake scenarios for I&C behind-the-meter storage were derived using Element Energy's consumer choice model, where I&C customers are divided into archetypes, based on different business types, and uptake is based on the payback period for investing in a battery and the willingness-to-pay of I&C organisations. Revenues from different sources are combined to find the maximum level of benefit that a storage owner could aggregate. These include wholesale price arbitrage[62], the Industrial Conservation Initiative (ICI)[63], operating reserve[64], regulation service, the capacity market[57], and the energy efficiency auction pilot. Of these, the ICI is the dominant revenue stream with a significant impact on uptake in each scenario[65]. In the Low and Medium scenario, these revenues are only accessible for customers with peak demand > 1MW. In the High scenario, these revenues are also accessible to manufacturing and warehouse archetypes with a lower peak demand. With most revenue streams only being available to customers with peak demand greater than 1MW, the modelling shows a significantly higher uptake of storage for customers connected to the high voltage network compared those connected to the low voltage network.

Figure 70 shows how these assumptions result in trajectories that reach between 129 - 381 MW in 2050. Pathways increase from a baseline of 11.8MW, with a pipeline ranging between 12.8MW in the Low scenario and 23.5MW in the High scenario.

[62] IESO, Hourly Ontario Energy Price, 2022
[63] IESO, Industrial Conservation Initiative Backgrounder, July 2022
[64] IESO, Ancillary Services, 2022
[65] Participants in the ICI pay global adjustment charges based upon their level of contribution to the top five hours of demand throughout the year. ICI revenues are calculated as the global adjustment charge that could be avoided by demand shifting with energy storage.

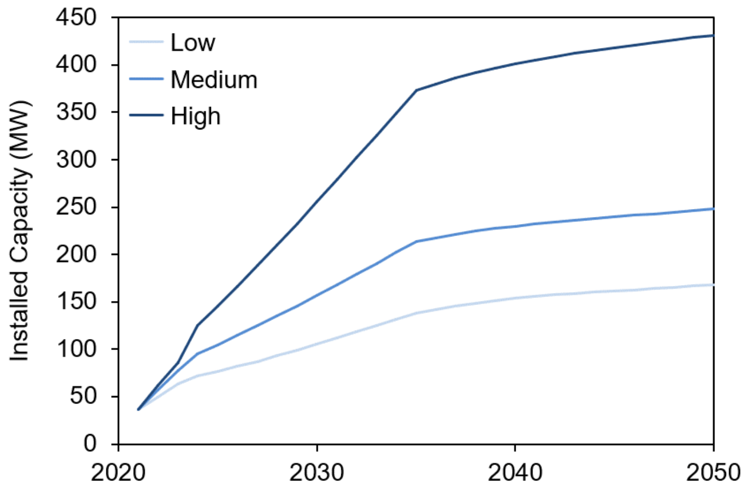


Figure 70: Installed capacity of I&C behind-the-meter battery storage in Toronto Hydro's network area out to 2050.

5 Network Impacts

Following the creation of the Future Energy Scenarios for Toronto Hydro, these datasets were loaded into Element Energy's FES Model to project the load growth and generation on the network out to 2050. This model projects the annual consumption and peak electricity demand for each of the 88 assets on the network as well as for the network as a whole, in order to provide a complete picture of the potential future changes to the network. In addition to the peak demand breakdown by asset, the peak by technology is also provided to facilitate a complete understanding of load growth and help the end user to plan and target network investments. Element Energy's load modelling systems are currently active across various electricity distribution companies and have a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. As such, the FES Model is fully equipped with the latest innovations in this area.

5.1 Load Modelling Process

The load modelling process used by the FES Model can be divided into four main calculation stages (Figure 71Figure 71): technology counts, annual consumption and generation, profile shapes and peak demand, and scaling calibration. Technology counts define the raw numbers of each technology (or capacity figures in the case of generation and storage) and how they are distributed across the network. This information is then leveraged along with data regarding the characteristics of each technology in order to calculate annual consumption or generation (MWh) values. Peak demand (MW) is subsequently established through the application of load profiles, which describe how the energy consumption of each technology is distributed across the year. Finally, the scaling calibrates modelled results by aligning them with real network load data provided by the electricity distributer.

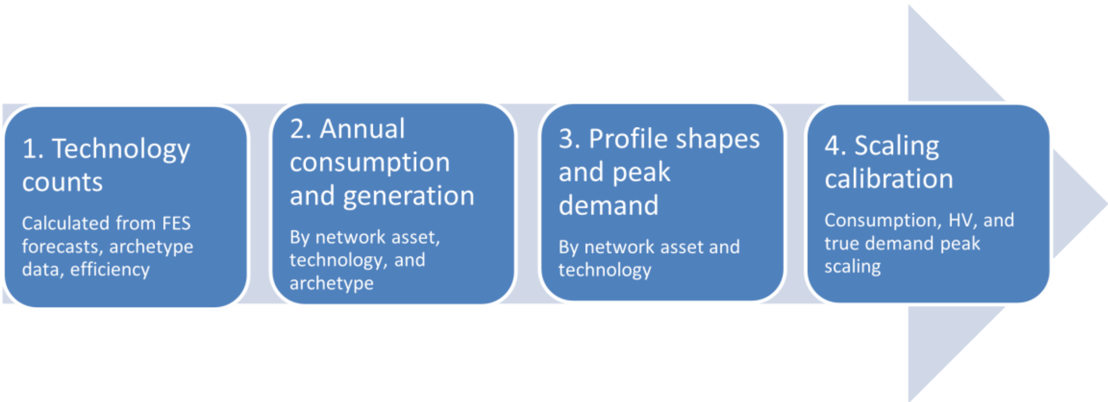


Figure 71: The main stages of the load modelling process.

Technology Counts

The first step of the process is to find the number of each technology (referred to as counts) in each year by transformer station bus and archetype. This typically begins with feeding in data from the FES, namely the geo-distributed technology projections and number of customers served by each transformer station bus (customer counts). These counts are then mapped to specific assets by leveraging the network topology which describes the connectivity between assets across Toronto.

Annual Consumption and Generation

The annual consumption and generation step involves finding how much energy is consumed or generated by a given technology in each year. Typically, this will leverage the counts as well as any information regarding the characteristics of each technology and customer type. This behavioural data varies by sector and may include such datasets as electric vehicle mileage, heating technology efficiencies and generation capacity factors.

The following steps are focused on demand, however a similar process is used for generation calculations.

Profile Shapes and Peak Demand

Following calculation of consumption values, the next stage in the load modelling process is the calculation of peak demand (MW), which is achieved primarily through the application of load profiles. Load profiles describe how the annual consumption from each technology and archetype is distributed across the year, defined for each month at a half-hourly resolution, as shown in Figure 72 for domestic core demand. These profiles are distinct for every key driver of load and there also exist options to use a minimum or average profile depending on the desired model outputs.

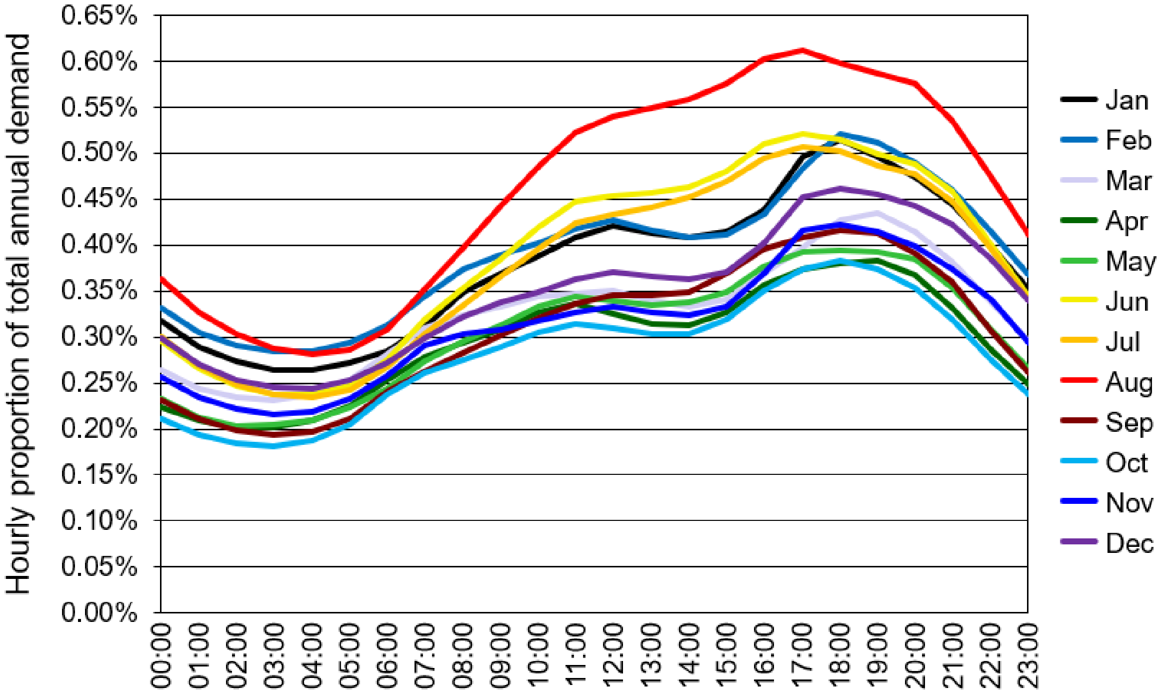


Figure 72: Load profiles for domestic core demand.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be found by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted.

Scaling

Following calculation of annual consumption and peak demands, the results are calibrated by aligning values with real data from network assets. This dataset was provided by Toronto Hydro and processed by Element Energy in three scaling stages: consumption scaling, high voltage (HV) customer scaling and true demand peak scaling. The scaling steps begin with coarse adjustments at system level and finish with calibration of every technology at every transformer station bus, to make sure that the modelled load is fully aligned with real measured data from Toronto Hydro.

The consumption scaling calibrates the FES model by calculating a system-wide consumption estimate based upon Toronto Hydro consumption data aggregated from all customers connected to the network. This estimate is then compared with the base year modelled system consumption values from the FES model and appropriate scaling is applied. The HV scaling process then calibrates the model outputs by making scaling adjustments to the high voltage customer loads. The final calibration step, true demand peak scaling, focuses in on each technology at each transformer station bus for which appropriate monitoring data is available, to ensure results are as accurate as possible. This is a more granular process than consumption scaling since true demand peak scaling applies unique scaling factors at each transformer station bus to ensure alignment both in total system load and individual asset loads.

5.1.1 Load Modelling Case Study: Low Carbon Heating

The type of data inputs that are used and the way in which they are processed is specific to the technology that is being modelled and therefore, the focus here is on the modelling process for the heating sector as one example (Figure 73Figure 73). In this case, the FES inputs include technology projections, building archetype definitions/distributions[66], new build growth, building demolition rates, and thermal efficiency trends. This case-study focuses specifically on the first two steps of the load modelling process since the peak demand calculation and scaling stages are generic and applied in the same way for all sectors.

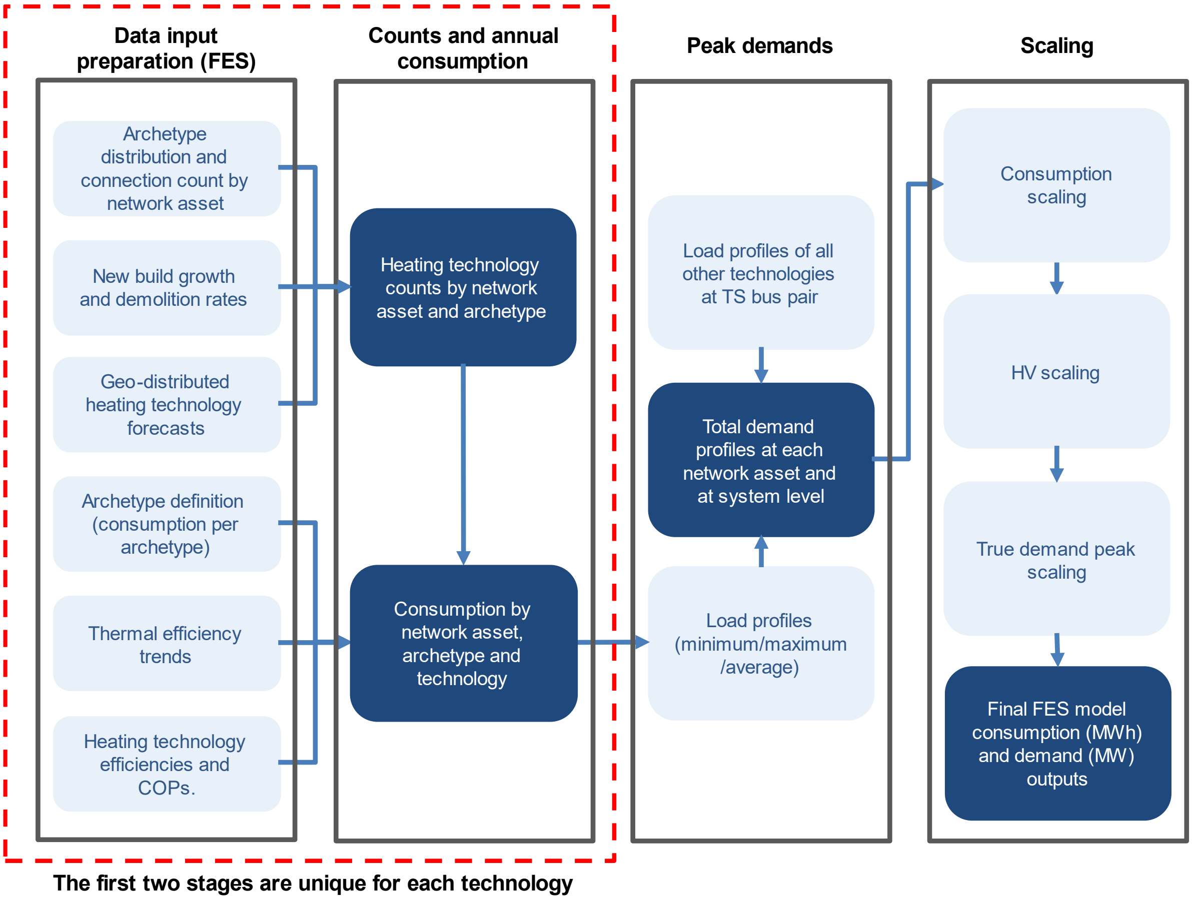


Figure 73: Detailed diagram of the load modelling process.

Technology Counts

For the heating sector, technology counts are found by first combining the archetype distribution, connection counts, new build growth, and building demolition rates to determine the number of customers of each archetype at each transformer station bus. Heating technology numbers are then established by applying the archetype specific heating technology uptake trends from the FES to find the number of each heating technology by archetype at each transformer station bus, for each year in the analysis horizon.

Annual Consumption

Once the heating technology counts are established, the annual consumption may be calculated by feeding in information about the typical characteristics of each heating technology and each building archetype. This

[66] Element Energy's FES modelling involves the definition of a set of archetypes that describe the different types of building that occur within Toronto. See section 4.1.1 for further details. The archetype distribution defines the proportion of each archetype at each transformer station bus.

includes heating technology efficiencies[67], thermal efficiency trends, and archetype definitions, which contain information about the average annual consumption for each consumer archetype.

Peak demands and Scaling

Following the annual consumption step, most technologies follow a similar methodology for the peak demand and scaling calibration. As detailed in Section 5.1, peak demands are found through the application of load profiles, which is followed by the three scaling stages (consumption, HV, and true demand peak).

5.2 Network Level Results

The final results of the load modelling process are summarized in Figure 74, which illustrates how the projected winter and summer system peak loads vary between different scenario worlds across all modelled years. Throughout the 2020s, summer peak is greater than winter peak and there is little variation across the scenarios, however, by 2050 the scenario worlds diverge considerably; Net Zero 2040 has the lowest system load, followed by Consumer Transformation, Steady Progression and System Transformation.

Figure 74 also shows the two low-efficiency scenarios, which are based upon Consumer Transformation and Net Zero 2040. More detail on the scenarios is given in section 2. The purpose of these sensitivity scenarios is to illustrate what the maximum system peak could be, caused by high levels of electrification without any measures to counter the added demand. These sensitivities represent the highest-load scenarios and would therefore lead to the highest levels of grid constraints and reinforcement costs.

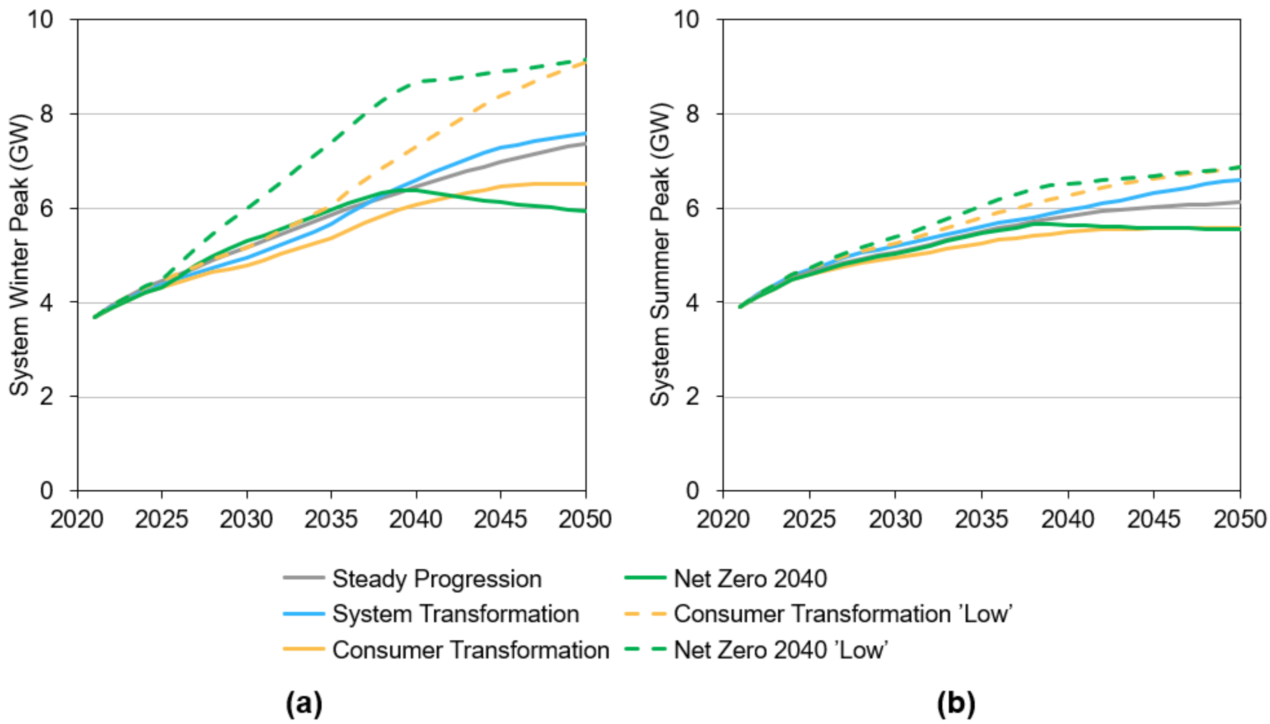


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Figure 74: Network peak in (a) winter and (b) summer for the four main scenario worlds and two low-efficiency sensitivity cases.

These results can be explained with reference to the scenario framework in Section 2 and the assumptions surrounding key drivers of load. In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily caused by high levels of air conditioning demand which constitutes a large

[67] For heat pumps, this also includes coefficients of performance.

portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating.

The 2030s see the time of network peak shifting to winter, with load driven by heat pump uptake and electric vehicles. As these technologies become more established, they are taken up in large numbers especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s, however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

These effects are seen most clearly in the Net Zero 2040 pathway, which has one of the higher system peaks during the 2030s, but by 2050 it is the lowest of all six scenario worlds at 5.9 GW. Rapid uptake of low carbon technologies drive load growth in the early years, however, improvements in energy efficiency, both thermal and non-thermal, balance out this effect and having achieved full decarbonization by 2040, the system peak then begins to fall. By 2040, heating and transport have fully transitioned to low carbon alternatives, relying primarily on electric technologies such as EVs and heat pumps. After this point, the energy system continues to see a sustained growth in distributed generation and flexibility measures, which help to meet the high peak demands caused by early electrification. Furthermore, the 2040s see additional improvements in energy efficiency, which reduce overall energy consumption, as well as continued high levels of consumer engagement, shifting demand away from times of high grid congestion. As a result, this is the only scenario which sees a reversal of previous trends such that peak demand begins to decrease.

Consumer Transformation has a consistently low peak demand and is the lowest of all scenarios until the early 2040s. Many of the factors that produce this trajectory are shared with Net Zero 2040 including high consumer engagement, participation in flexibility markets and an overall shift towards a smarter energy system. However, decarbonization is achieved ten years later in this scenario due to the uptake of low carbon technologies following a more gradual trajectory compared to Net Zero 2040. Consequently, peak demand is lower in the early years, however the later years see the system peak plateau at approximately 6.5 GW.

The two low-efficiency sensitivity scenarios, which are based on Consumer Transformation and Net Zero 2040, illustrate the network impacts of high electrification coupled with low levels of distributed generation, efficiency, and flexibility. These scenarios show the network would experience higher peaks under these conditions and hence represent the highest possible constraints that Toronto Hydro's network might experience. Implicitly, these also represent the situations requiring the largest amount of network reinforcement and network investment. Over the modelled time period, the Net Zero 2040 sensitivity presents the highest peak load, due to assumptions surrounding the early adoption of low carbon technologies. However, the 2050 peak demand on both sensitivities is the same since both achieve full decarbonization, with a similar technology mix, by 2050.

Steady Progression has a consistently higher peak despite relatively lower levels of electrification, which can be largely attributed to lower levels of energy efficiency, distributed generation, and flexibility/storage. Consequently, the system peak in 2050 is projected to reach 7.4 GW. This scenario world illustrates clearly how a less ambitious decarbonization plan does not necessarily lead to lower electricity demand on distribution networks.

System Transformation has the highest system peak in 2050 out of all the main four scenario worlds. Until the late 2030s, it follows a similar trajectory to Steady Progression and Consumer Transformation, after which peak demand begins to increase at a faster rate, reaching 7.6 GW in 2050. The main cause of this is that, despite a partial reliance on retained gas infrastructure, this scenario world still assumes that electrification will be the primary route to decarbonization. However, System Transformation does not contain the same level of ambition in efficiency improvements, renewable generation, flexibility, and smart technologies. Therefore, the demands of high electrification are not offset to the same extent as in the Consumer Transformation and Net Zero 2040 scenarios.

Figure 75 shows the scale of the impact of flexibility, efficiency and behind-the-meter renewable generation on the summer and winter peaks in the Consumer Transformation and Net Zero 2040 scenario worlds. The value to the network of these measures is clearly largest in winter, though summer peak is still significantly reduced in both scenarios. The reduction of peak demand by more than a third (Net Zero 2040) would avoid the need for a significant amount of network reinforcement, and consequently would save Toronto Hydro a large amount of investment.

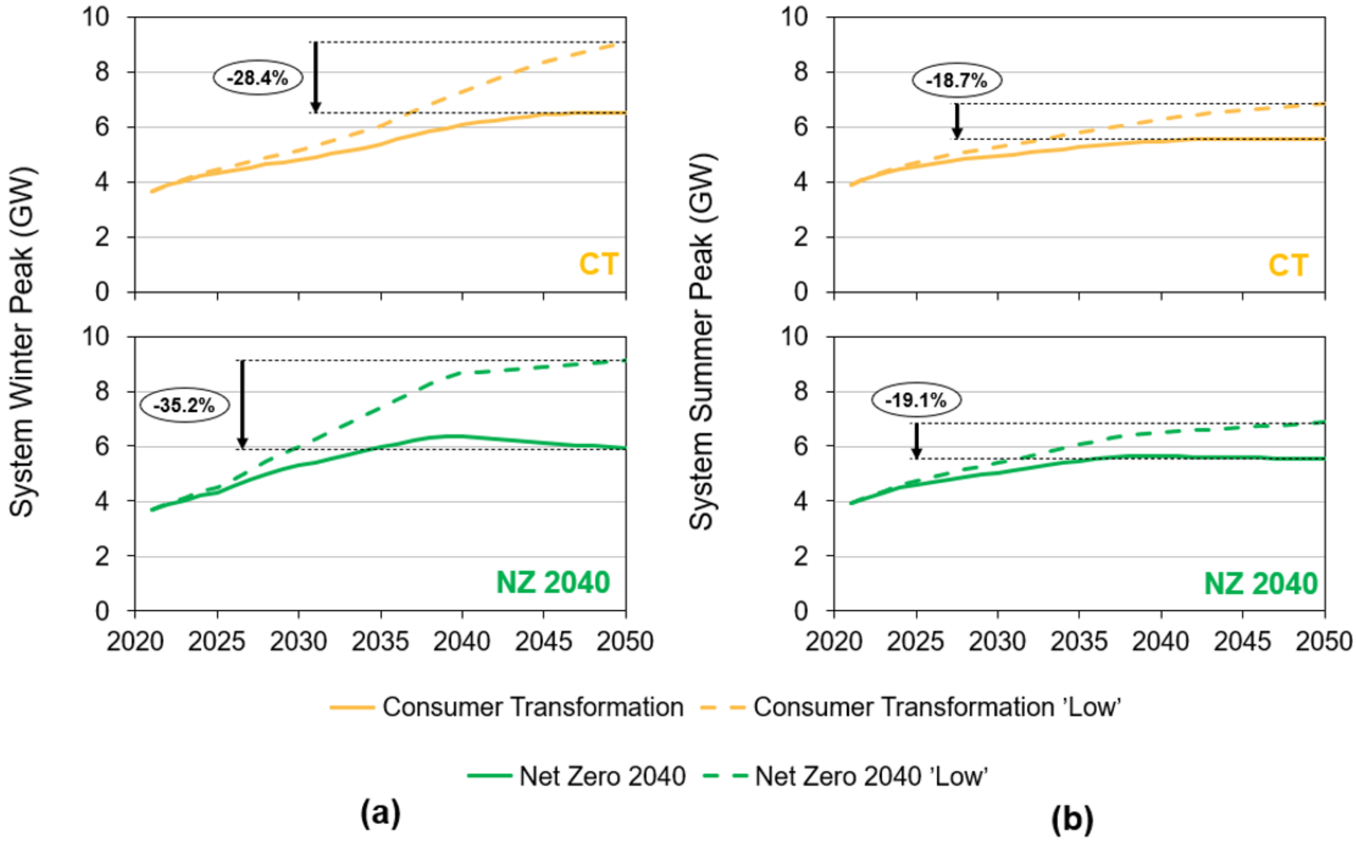

Figure 75: Comparison of peak true demand in the Consumer Transformation and Net Zero 2040 scenarios in (a) winter and (b) summer, in the Standard and Low-Efficiency sensitivity cases

6 Conclusions

This report has detailed the Future Energy Scenarios developed for Toronto Hydro that map out a number of future pathways for Toronto's energy system and evaluate the ways in which this may impact the distribution network. In order to capture the range of uncertainties in a coherent and meaningful way, four key 'scenario worlds' were developed, each built up of individual projections for different technology sectors. projections were developed using Element Energy's suite of bottom-up consumer choice and willingness-to-pay models which were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, reviewing previous studies, datasets, and policy.

This work has found that, in all scenario worlds, Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of heating and transport sectors which are expected to see widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to EVs across all vehicle types. Similarly, all domestic, commercial and industrial buildings are projected to be heated by heat pumps or electric resistive heating by 2050 for all scenarios that achieve net zero within this timeframe.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is that it identified the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase rapidly, as demonstrated by the two sensitivity scenario worlds. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network.

Toronto Hydro's Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance to the attainment of a 2040 or 2050 net zero target, with the Future Energy Scenarios illustrating that this target will require key policy support for it to be achieved. There are many factors that can influence this at all levels of the energy system, but policy is one of the higher impact options observed in the modelling for accelerating the pace of change. Finally, the magnitude of changes to the energy system in recent years, both locally and globally, highlight the importance of maintaining an up-to-date understanding of the latest trends. Technological advancement, evolving supply chains, changing consumer attitudes, and evolving government policies have the potential to precipitate considerable impacts in technology deployment levels. As a result, regularly refreshing network load scenarios with the latest available data and learnings is an important part of planning for these changes and the low carbon energy transition.

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D5 2025-2029 Grid Modernization Strategy

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D5.1 Introduction: The Grid Modernization Imperative

Toronto Hydro is at an important turning point in its modernization journey. A confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. Distributed Energy Resources) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Trends, forecasts, and scenarios for the underlying drivers of the grid modernization imperative are covered in detail throughout Toronto Hydro's 2025-2029 Distribution System Plan, including in the following key sections:

- **Section D4** covers the projected impacts of decarbonization, electrification, and digitalization of the economy (e.g. data centre proliferation) on system utilization;
- **Section E3** provides an overview of Toronto Hydro's expectations for growth in DERs ("Distributed Energy Resources");[1] and
- **Section D2.1.2** discusses the impacts of climate change on grid performance and resiliency.

Toronto Hydro expects that the trifecta of electrification, DER proliferation, and worsening climate change will place increasingly complex demands on the utility's system assets and operations. The utility's central concern is securing its ability to continue delivering safe, reliable, and affordable electricity over the long-term and in the face of uncertainty. Climate change and electrification will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy.

[1] In Toronto Hydro's system context, distributed energy resources are largely centered around solar technologies, energy storage systems, wind, natural gas, biogas, and customer assets for demand response programs. In the future, the term may expand to include micro-wind and fuel cells.

Furthermore, potentially high levels of DER penetration will add complexity and instability to the system, exacerbating the challenge of maintaining today's high standards of reliability and safety performance.

This escalation of risk and demand cannot be fully or efficiently met with a status-quo approach. Advanced, digital technologies will be necessary to upgrade the operating characteristics and capabilities of the grid, effectively unlocking incremental value from traditional infrastructure. These technologies – including sensors, remotely operable switches, next generation smart meters, predictive and prescriptive analytics, and automation schemes – will enable Toronto Hydro to not only adapt to the challenges it foresees in 2030 and beyond, but also take advantage of the opportunities presented by new kinds of customer-owned technologies such as battery storage and flexible loads for the benefit of all ratepayers.

D5.1.1 Toronto Hydro's 2025-2029 Grid Modernization Strategy

This document serves as a comprehensive overview of Toronto Hydro's 2025-2029 Grid Modernization Strategy and a guide to where the detailed investment plans can be found through the DSP ("Distribution System Plan"). As described throughout this summary document, Toronto Hydro has developed a grid modernization strategy which addresses emerging challenges and opportunities in a manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. From a materiality perspective, most of these investments are a continuation or renewal of programs that Toronto Hydro has been rolling-out at a gradual pace over the last two decades (e.g. grid sensors; remote-operable switches; smart meters), while others (e.g. achieving "self-healing" grid operations) represent the culmination of transformational efforts that have been a part of the utility's long-term modernization roadmap for many years. In many cases – including, for example, the introduction of mid-line reclosers and the implementation of a "self-healing" grid – Toronto Hydro's objectives are informed by the success of peer utilities in other progressive jurisdictions – including various U.S. states and Canadian jurisdictions such as Alberta – where investments in digital transformation and automation have proceeded at a more rapid pace in recent years.

Complimenting this focus on proven technology is a secondary emphasis on innovation. There are certain challenges – e.g. cost-effectively increasing the amount of distributed generation that can connect to congested feeders – for which the optimal technological and commercial solutions are not yet settled or mature. In these areas, Toronto Hydro is planning to increase its investment in pilot projects and industry partnerships, which the utility believes can contribute to accelerated progress across the entire sector.

The remainder of this introductory section provides a brief overview of the differences between the traditional versus modernization grid. **Section 2** provides a detailed overview of the three major portfolios that constitute Toronto Hydro's Grid Modernization Strategy: (i) Intelligent Grid, (ii) Grid Readiness, and (iii) Asset Analytics & Decision-making. **Section 3** contains a series of appendices which provide more detailed discussions of certain key capabilities and projects that are not discussed in detail elsewhere in the DSP.

For a detailed summary of the how Toronto Hydro determined the expenditure levels for its 2025-2029 modernization programs and the role of Customer Engagement, please refer to Section E2 of the DSP. For an overview of how Toronto Hydro's modernization strategy is reflected in the utility's 2025-2029 key performance targets, please refer to Exhibit 1B, Tab 3, Schedule 1.

D5.1.2 Redefining Distribution Capabilities: The Traditional versus Modern Grid

In the traditional concept of the electric power grid in Ontario, seen in the top of Figure 1 below, the grid connects large central generating stations through a high-voltage transmission system to a distribution system that directly feeds customer demand. Generating stations consist primarily of nuclear- and hydro-powered turbines that spin to produce electricity. The transmission system in this model historically grew from local and regional grids into a large interconnected network that is managed by coordinated operating and planning procedures. Peak demand and energy consumption also grew at predictable rates, and technology evolved in a relatively well-defined operational and regulatory environment.

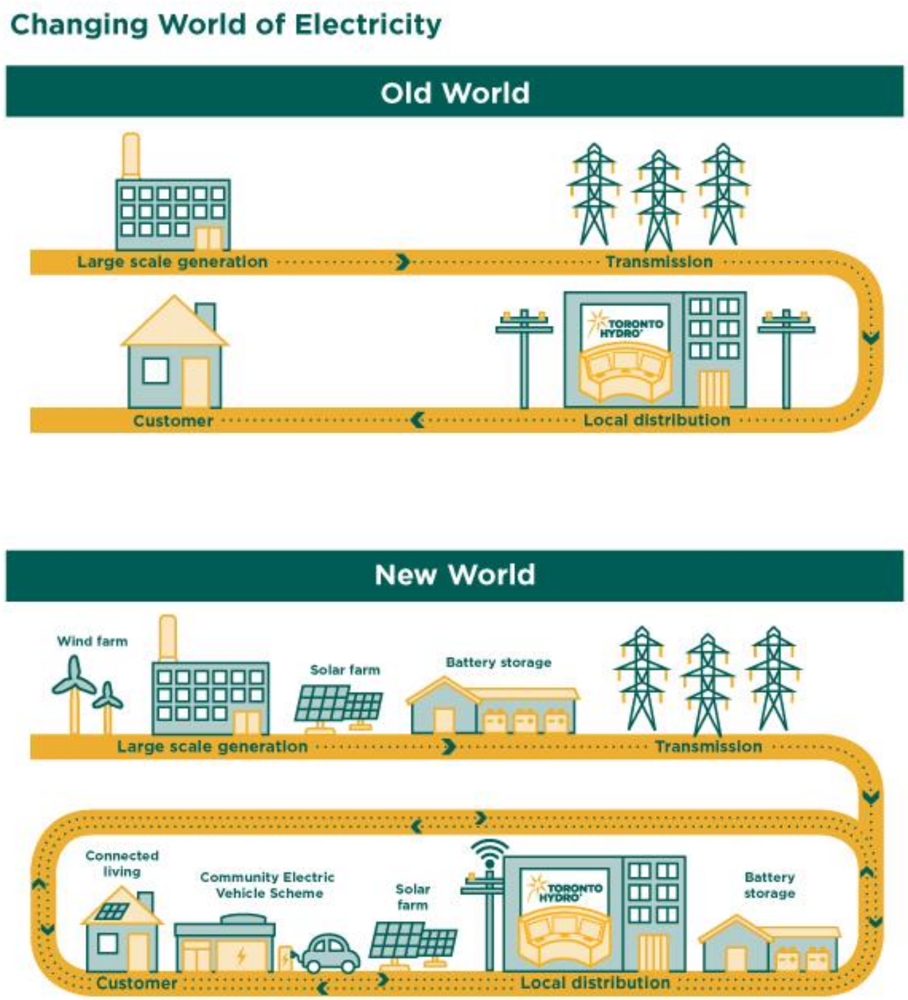


Figure 1: The Changing World of Electricity: Old vs New

The grid modernization imperative now requires utilities to go beyond "simply" delivering reliable one-way power to customers. Technology on the grid is changing, and the traditional, unidirectional model of electrical generation, transmission, and distribution is set to change with it. Segments of customers are poised to become prosumers: no longer will they only consume power, but they will also have the capability to supply the grid with power. At the same time, electrification will not only put additional load on the grid, but also create opportunities for flexibility and creative new solutions for load management. This represents an unprecedented challenge and opportunity to move the grid into a new era of reliability, availability, and efficiency that will contribute to economic, social, and environmental health and ensure that electricity can rise to the challenge of being the primary, and perhaps the only, source of energy in many consumers' lives. This will be made possible through proactive grid and operational investments to enable advanced monitoring and automation and digital transformation as seen in the lower half of Figure 4

Much of the required technology for the transition to a modernized grid already exists on the grid today, and in many cases, it is a matter of expanding its deployment to achieve sufficient granularity of grid transparency and control, and then building upon these field technologies with predictive and prescriptive analytics and automated controls. For example, sensors and remotely-operable SCADA ("Supervisory Control and Data Acquisition") switches have existed on the grid for quite some time, but using them to sense where a fault has occurred and remotely operating the SCADA switches to isolate the fault is the additional benefit of a modern, connected grid. A comparison of technologies in the traditional grid vs. the modern grid is summarized in Table 1 below.

Table 1. Traditional vs. Modern Grid.

Characteristics	Traditional	Modern / Smart Grid
Technology	**Electromechanical:** Traditional energy infrastructure is electromechanical. This means that it is of, relating to, denoting a mechanical device that is electrically operated. This technology is typically considered to be "dumb" as it has no means of communication between devices and little internal regulation.	**Digital:** The smart grid employs digital technology allowing for increased communication between devices and facilitating remote control and self-regulation.
Distribution	**One-way Distribution:** Power can only be distributed from the main plant using traditional energy infrastructure.	**Two-way Distribution:** While power is still distributed from the primary power plant, in a smart grid system, power can also go back up the lines to the main plant from a secondary provider. An individual with access to alternative energy sources, such as solar panels, can actually put energy back on to the grid.
Generation	**Centralized:** With traditional energy infrastructure, all power must be generated from a central location. This eliminates the possibility of easily	**Distributed:** Using smart grid infrastructure, power can be distributed from multiple plants and substations to aid in balancing the load, decrease peak time strains, and limit the number of power outages.

Characteristics	Traditional	Modern / Smart Grid
	incorporating alternative energy sources into the grid.	
Sensors	**Few Sensors:** The infrastructure is not equipped to handle many sensors on the lines. This makes it difficult to pinpoint the location of a problem and can result in longer downtimes.	**Sensors Throughout:** In a smart grid infrastructure system, there are multiple sensors placed on the lines. This helps to pinpoint the location of a problem and can help re-route power to where it is needed while limiting the areas affected by the downtime.
Monitoring & Control	**Manual Monitoring, Limited Control:** Due to limitations in traditional infrastructure, energy distribution must be monitored manually.	**Self Monitoring, Pervasive Control:** Monitors itself using digital technology, allows it to balance power loads, troubleshoot outages, and manage distribution without need for direct intervention from a technician.
Restoration	**Manual:** In order to make repairs on traditional energy infrastructure, technicians have to physically go to the location of the failure to make repairs. The need of this can extend the amount of time that outages occur.	**Self-Healing:** Sensors can detect problems on the line and work to do simple troubleshooting and repairs without intervention. For problems related to infrastructure damage, the smart grid can immediately report to technicians at the monitoring centre to begin the necessary repairs.
Customer Choices	**Fewer:** The traditional power grid system infrastructure is not equipped to give customers a choice in the way they receive their electricity. Alternative energy sources, for example, have to be separated from power plants and traditional grid infrastructure.	**Many:** Using smart technologies, infrastructure can be shared. This allows more participants and forms of alternative energy to come on the grid, allowing consumers to have more choice.
Flexibility	Non-Flexible and Non-Controllable Loads	Flexible and Controllable Loads

D5.2 Grid Modernization Strategy Overview

The Grid Modernization Strategy outlines a five-year plan with objectives for accelerating the transformation of Toronto Hydro's existing grid infrastructure into a more technologically advanced distribution system. The overall goal of this strategy is to deliver on the utility's long-term vision of improving reliability and resiliency, efficiently accommodating and managing an expected influx of DERs, and preparing for electrification across various sectors. It also aims to leverage improved grid observability (i.e. real-time data from sensors) and advanced analytics to enable data-driven decision-making for applications such as predictive asset management, grid planning and optimization, and load forecasting.

The strategy focuses on three core areas as shown in Figure 2 below, namely: Intelligent Grid, Grid Readiness and Asset Analytics & Decision-making. Technology serves as the binding force to enable interconnection between the three core areas.

Figure 2: The Grid Modernization Pieces

The **Intelligent Grid** area is focused on expanding observability and controllability of the grid such that automated tools like FLISR ("Fault Location, Isolation, and Service Restoration") and ADMS ("Advanced Distribution Management System") are able to provide enhanced fault restoration capabilities, improve operational efficiency, and better optimize system configuration and real-time performance. The **Grid Readiness** area focuses on building capabilities to support decarbonization and decentralization of energy resources, with a focus on leveraging field technologies and analytics, including major platforms like DERMS ("Distributed Energy Resource Management System" or "Energy Centre"), to better facilitate DER connections and optimize DER capabilities for services such as demand response. The last area, **Asset Analytics & Decision-making**, encompasses the digital advancements required to lay the foundation for a future-proof digital core that can support the large volumes and varieties of data obtained from initiatives in the other two core areas, leverage advanced analytical capabilities to extract more value from current assets, and drive greater efficiency in investment planning.

The following sections present details about the three focus areas and strategic initiatives tied to them.

D5.2.1 Intelligent Grid

The ***Intelligent Grid*** portfolio within the Grid Modernization Strategy is designed to improve reliability, resiliency and situational awareness of the distribution system. The portfolio places a strong emphasis on harnessing the power of advanced field technologies and operational systems to enhance grid intelligence and responsiveness. The key components of Toronto Hydro's Intelligent Grid concept are illustrated in Figure 3 below.

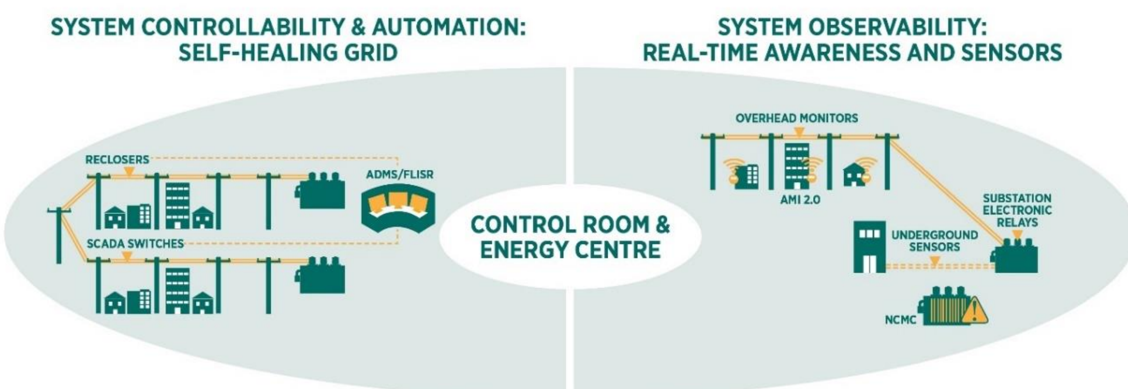


Figure 3: The Major Components of an Intelligent Grid

Investments in this portfolio aim to strengthen two domains of the distribution system, namely: System Observability and System Controllability and Automation.

- **System Observability: Real-Time Awareness & Sensors** entails adding more sensors, relays and monitoring technology at specific nodes across the distribution grid, including customer meters. These assets will provide additional data collection points across the grid, which Toronto Hydro will leverage to improve overall situational awareness ("grid transparency"), facilitate quicker fault location, and gain access to important insights at the edge of the grid. This data will be used in conjunction with advanced analytics platforms to analyze variables such as voltage levels, asset loading, and power flows. Improved system observability will help Toronto Hydro proactively identify developing issues, respond promptly to events, and utilize available resources efficiently.

- **System Controllability & Automation: Self-Healing Grid** entails (i) adding more switching assets on the grid – mainly SCADA-controlled tie switches, sectionalizers, and reclosers – and (ii) implementing automation technologies including FLISR ("Fault location Isolation and System Restoration"). The switching devices will provide Toronto Hydro with greater control and flexibility over grid operations, allowing remote switching and monitoring and improved fault isolation and restoration. With increased system controllability, Toronto Hydro can respond swiftly to changing conditions, optimize grid performance in real-time, reduce the number of customers impacted and the duration of interruption during faults or disruptions, and reduce truck rolls. These investments will also establish the basis for a "self-healing," automated grid, which Toronto Hydro aims to implement beginning in 2030 following planned upgrades to the utility's ADMS (which includes the FLISR technology that is required to enable distribution automation).

Section D5.2.1.1 and D5.2.1.2 below provide additional details on each of these categories. For a high-level summary of all the initiatives and investment programs that constitute the Intelligent Grid portfolio, refer to Section D5.2.1.3.

D5.2.1.1 System Observability: Real-Time Awareness and Sensors

Expanding visibility into the operating conditions of the distribution grid is a critical part of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029, and will help the utility achieve three core capabilities:

1. **Enhanced Fault Location:** Locating faults and other system disturbances faster and more efficiently in order to improve reliability and operate the grid more cost-effectively.
2. **Enhanced Decision-making and Grid Optimization:** Providing greater insight into real-time feeder and asset loading, condition, and other relevant operating characteristics. This assists the utility in managing short- and long-term uncertainty as well as driving optimal real-time operational decisions and longer-term investment planning decisions.
3. **Enhanced Asset Diagnostics:** Greater visibility into high-risk and previously hard-to-monitor assets will improve asset diagnostics, mitigating the risk of asset failure and impacts to personnel safety and environmental damage.

The most significant investment Toronto Hydro is making to enhance grid observability in the 2025-2029 rate period is the replacement of end-of-life, legacy smart meters with next generation smart meters (also known as Advanced Metering Infrastructure 2.0 or "AMI 2.0"). While AMI 2.0 has the long-term potential to provide the high frequency, multi-parameter insights that will be required to address certain emerging operational pressures and requirements, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in data analytics, digital systems integrations, and business process changes. In the interest of providing immediate benefits to customers while diversifying the long-term options available to Toronto Hydro for monitoring the system, the utility is planning to explore and leverage a broader suite of field technology investments for the 2025-2029 period within the System Enhancements investment program (Exhibit 2B, Section E7.1).

This will involve the targeted deployment of sensors that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid. To achieve these benefits, the System Observability segment (Section 7.1.1.3) will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors. The NCMC ("Network Condition Monitoring & Control") (Exhibit 2B, Section E7.3) and Stations Renewal (Exhibit 2B, Section E6.6) programs add further monitoring and communications capabilities to various aspects of the distribution system.

Toronto Hydro expects that investments to improve observability will deliver both tactical operational benefits and long-term asset management benefits. As the distribution grid becomes more complex – with the addition of more devices and evolving customer interactions with the grid – it is essential that investments in grid observability keep pace, allowing Toronto Hydro to make informed operational and asset management decisions. Targeted observability investments will enable more detailed insights into power flows by leveraging data from deployed field devices, in addition to more granular customer consumption data via AMI 2.0. The objective is to provide an accurate view of the state of the distribution grid, for applications such as automated fault management, DER management, and asset condition management. Furthermore, field devices such as sensors are significantly less expensive than building out new infrastructure to accommodate load growth. While these devices do not themselves provide additional capacity, they can be leveraged in targeted ways to ensure that Toronto Hydro's demand forecasts and assumptions are informed by increasingly granular information, and that appropriately sized capacity investments are planned for the right parts of the system at the right time. They will also help capacity optimization as well as more effective non-wire solutions planning and operations.

Investment programs within the System Observability portfolio will focus on service areas with significant operational value (e.g., DER-rich feeders, feeders with poor visibility, feeders with poor reliability, etc.). Before rolling out new observability technologies at scale, Toronto Hydro will run smaller pilots to test the technology for specific use cases, ensuring that the benefits are clear for customers, and that sufficient time is allotted to pursue potential overlapping use cases related to AMI 2.0. Ultimately, Toronto Hydro is looking to gain a broad range of experience developing applications and use cases for potentially scalable sensor technologies and AMI 2.0 in the 2025-2029 rate period, with the goal of initiating a fully formed observability strategy in 2030-2034.

The portfolio objectives will be primarily addressed through the following initiatives, which are summarized in the section below.

1. Deployment of Overhead and Underground Sensors
2. Online Cable Monitoring
3. Transformer Monitoring
4. Network Condition Monitoring & Control
5. Stations Digital Relays
6. AMI 2.0

D5.2.1.2 System Controllability & Automation: Self-Healing Grid

In Toronto Hydro's grid modernization journey, System Controllability and Automation will continue to play a vital role in transforming the grid into an intelligent and responsive system. System controllability refers to the ability to actively manage and control grid operations in real time using remotely operated devices. These devices provide significant reliability and efficiency benefits in and of themselves, and are also the essential physical nodes which create the basis for a "self-healing" grid, i.e. a grid that can detect, isolate, and fix faults and disturbances in the grid in real-time, with minimal or no human intervention. The self-healing aspect is ultimately enabled by implementing advanced operational control technologies such as FLISR.

1. Preparing the Horseshoe System for Automation by 2030

One of the most significant objectives for Toronto Hydro's Grid Modernization Strategy in the 2025-2029 rate period is to advance the ongoing process of readying Horseshoe system feeders for the transition to a **self-healing operation beginning in 2030**.[2] Specifically, Toronto Hydro is aiming to have 90 percent of feeders in the Horseshoe system ready for automation by 2030. This will be accomplished in part through the System Enhancements program, which will install SCADA-controlled switches and reclosers on at least 34 feeders to bring them to the minimum optimal number of switching points per feeder of 2.5, which is required to enable an effective self-healing automation scheme.[3]

The other essential part of Toronto Hydro's strategy toward preparing a self-healing grid is FLISR implementation. FLISR is a centralized software system that works to automatically detect the location of a fault, isolate the affected section of the network, and reroute power to as many customers as possible, while minimizing the impact on the overall system. FLISR works together with the aforementioned physical field devices to enable distribution automation.

Implementing fully automated FLISR within Toronto Hydro's dense, urban service territory is a complex and significant undertaking which the utility plans to address using a methodical and staged approach over the 2025-2029 rate period. The utility is planning to implement "manual FLISR" at an average of five transformer station areas per year between 2025 and 2028, ultimately covering all 20 transformer stations in the Horseshoe area prior to 2030. Manual FLISR refers to the concept of running the FLISR system in the control room where the system suggests switching instructions to the operators to execute for power restoration. This affords system controllers the opportunity to review the FLISR system's prescribed switching operations to ensure they are safe and appropriate before implementing the switching plan. Running manual FLISR for an adequate period of time is an

[2] The Horseshoe system is the open-loop primary distribution system that serves all of the City of Toronto's inner suburbs.
[3] The 2.5 standard refers to the need for a feeder to have a minimum of two SCADA-controlled sectionalizing points and one SCADA-controlled tie-point, with the latter counting as 0.5 because it belongs to two feeders simultaneously.

important stepping-stone toward implementing automatic FLISR as it ensures that automation can be implemented with the necessary confidence that it will function properly, with the intended benefits and minimal risk to safety and system integrity. In parallel with the roll-out of manual FLISR, Toronto Hydro plans to make essential upgrades to its ADMS platform in 2025-2029, readying those systems to support fully automated FLISR in 2030 and beyond.

A U.S. Department of Energy report on five utilities that implemented FLISR projects found that, on average, FLISR reduced the number of CIs ("Customers Interrupted") by up to 45 percent and reduced the CMIs ("Customer Minutes of Interruption") by up to 51 percent for a relevant outage event. This was generally consistent with utility expectations of system performance going into the projects. Fully automated switching schemes generally outperformed operator-initiated remote switching schemes.[4] Toronto Hydro expects to see significant benefits from its roll-out of automatic FLISR in 2030 and beyond.[5] Note as well that, as discussed in the U.S. Department of Energy's final report on the results of its Smart Grid Investment Grant Program, utilities that successfully integrated their distribution automation schemes with observability enhancing technologies were able to "remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information – often shaving hours or days off restoration time following major storms."[6]

Benefits such as these are a critical part of ensuring Toronto Hydro's grid is capable of cost-effectively delivering improved reliability and resiliency in anticipation of electrification and pressures from adverse weather. However, to be positioned to fully realize these benefits, the utility must invest in completing the milestones outlined above.

For more information on Toronto Hydro's FLISR system, please refer to Section D5.3.2.

[4] U.S. Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf
[5] It is important to note that the benefits cited from the U.S. Department of Energy Study rely upon the US standard for momentary outages of <5mins. Percentage improvements may be lesser for Toronto Hydro given the standard of <1min for momentary outages in Ontario. Regardless, the positive effective on the lived reliability experience of customers will be the same or similar. Note that the level of FLISR benefits achieved by a given utility is also dependent on that utility's unique operating reality.
[6] U.S. Department of Energy, Smart Grid Investment Grant Program Final Report Executive Summary, https://www.energy.gov/sites/prod/files/2017/03/f34/Final%20SGIG%20Report%20-%20Executive%20Summary.pdf

2. Additional Controllability Investments to Improve Reliability, Resiliency and Grid Flexibility

As noted earlier in this section, even without the advanced benefits of automated FLISR, the deployment of incremental remote-operable switching devices will have material benefits for reliability, resiliency and operational flexibility. Therefore, in addition to completing the "self-healing grid" strategy discussed above, Toronto Hydro is planning to continue deploying SCADA-controlled devices more broadly as part of the System Enhancements program. This includes continuing to deploy additional sectionalizers and tie switches on the feeders most in need of additional switching capabilities.

As a general design guideline for area rebuilds and new feeders, Toronto Hydro requires that there be no more than approximately 700 customers within a switching region or section. Currently, many feeders on Toronto Hydro's system do not meet this standard, meaning that these feeders have relatively limited flexibility to deal with certain contingency events and interruptions. This results in sub-optimal levels of reliability performance risk for affected customers. In 2025-2029, to support its reliability targets and improve the operational flexibility of the Horseshoe and Downtown overhead systems, Toronto Hydro is planning to install 298 SCADA operated switches and 220 reclosers, prioritizing feeders with the worst reliability performance and greatest reliability risk levels. For a detailed overview of these investments, refer to the Contingency Enhancement segment within the System Enhancements program (Section E7.1).

Note that reclosers are a new feature of Toronto Hydro's portfolio of grid technologies. A recloser is a device which automatically detects and interrupts fault conditions, and then re-establishes connectivity if the fault condition has been cleared. In other words, when a transient fault occurs downstream of a recloser (like a tree branch touching a line), the recloser will temporarily open the circuit to clear the fault and then automatically reclose it, restoring power. If the fault is persistent, the recloser will typically operate a pre-set number of times before locking out (remaining open) to ensure safety, automatically isolating faulted sections of the feeder such that customers on healthy feeder sections do not experience an interruption. Reclosers provide benefits to the system by substantially reducing the number of customers who experience a sustained interruption under certain high-impact fault scenarios.

Toronto Hydro completed a recloser deployment pilot project in early 2023, which successfully demonstrated that modern recloser technologies can work effectively on the utility's distribution system and that these units have the potential to contribute material improvements in the number of customers impacted by sustained outages in many of the higher-impact fault scenarios Toronto Hydro deals with on a regular basis.[7] Importantly, reclosers can also be operated remotely, much like a SCADA-operable load break switch, meaning that they will also form an integrated part of Toronto Hydro's FLISR-enabled distribution automation scheme. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, including high-impact contingency events such as major storms.

With the combination of these switching investments, Toronto Hydro expects to see benefits in CI ("Customer Interruptions") and CMO ("Customer Minutes Out"), as well as operational cost savings. Overall, Toronto Hydro estimates that by 2030, there will be improvements in the range of three to seven percent for SAIFI and four to seven percent for SAIDI on the overhead system due to Contingency Enhancement investments. Toronto Hydro has also estimated operational cost savings from the deployment of its SCADA switches to be about $22,500 per switch over its lifetime.[8] Finally, Toronto Hydro has also estimated the quantified customer reliability benefits of its 2025-2029 Distribution System Plan, which includes the benefits of additional switches and reclosers. This analysis can be found in Exhibit 1B, Tab 3, Schedule 1.

3. Advanced Distribution Management System ("ADMS") Upgrades

The FLISR capabilities discussed in the automation section above are part of a broader software solution known as an ADMS. At its core, an ADMS is a software solution that integrates and consolidates functionalities from several systems, such as the utility's Outage Management System ("OMS") and Distribution Management System ("DMS"), which handle a wide array of mission-critical outage management and distribution system management functions; SCADA, which enables real-time monitoring and control; and the DER Management System or DERMS, which monitors and controls DERs. The role of an ADMS is to provide the utility with a comprehensive and unified view

[7] Microprocessor relays employed in the latest generation of reclosers are able to identify the different types of faults that occur and be programmed to provide a faster, more appropriate response. Prior to this development, protection schemes – specially in high density areas with short feeders like the City of Toronto – often had to choose security and dependability over reduction in response times and increased feeder segmentation. Today's feeder protection devices must be ready to respond to more dynamic situations and the new generation of reclosers with microprocessor relays are key in this regard to address emerging challenges by improving segmentation and protecting Toronto Hydro's circuits and assets.

[8] Based on average truck roll cost of $300 per hour for one-hour, average number of SCADA switch operations per year (calculated over 2018-2022), and an average switch lifetime of 25 years.

of its operations by acting as a central hub which pulls data from, and interacts with, this constellation of software and systems.

Toronto Hydro's ADMS is poised to play an increasingly significant role in the utility's operations. As the grid evolves with the integration of distributed energy resources, electric vehicles, smart devices, and changing consumption patterns, the complexities of managing the network will also increase. The utility will require its ADMS to optimize the integration and management of DERs, leverage real-time data processing capabilities and analytics to manage the two-way flow of electricity and information as the grid becomes smarter, perform more advanced outage management functions (including FLISR), manage demand response programs, and leverage enhanced analytics and data integration to improve system and operational efficiency.

As part of its Intelligent Grid strategy for 2025-2029, Toronto Hydro plans to upgrade its existing systems into an ADMS platform that better integrates "best-fit" system components and will be capable of meeting the emerging demands on the grid while enabling efficiencies. Given the critical nature of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades are necessary in 2025-2029 to ensure the ADMS components have continued vendor support. Furthermore, many of Toronto Hydro's ADMS components operate in silos and have limited ability to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in longer outages. Upgrades to ADMS will ensure optimal components are enabled and these components are effectively integrated. These upgrades will also support future automation functionalities (e.g. in support of the self-healing grid) and improve business process efficiencies.

For more information on Toronto Hydro's planned ADMS upgrade project, please refer to Exhibit 2B, Section E8.4.

D5.2.1.3 Intelligent Grid Program Summaries

The Intelligent Grid technologies introduced above are summarized in Table 2. For more detail on each technology, please refer to the Investment Program column. For select technologies, more detail has been provided in the appendices of this strategy.

Table 2. Intelligent Grid Program Summaries

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Observability	Overhead & Underground Sensors	• Improves outage response time and quicker service restoration for customers • Improves SAIDI & SAIFI metrics through data that enables proactive asset management • Provides data for advanced analytics platforms and data-driven asset management decision-making	$4.7M	Exhibit 2B, Section E7.1 - System Enhancement
	Online Cable Monitoring	• Identifies cables at risk of failure before failure • Provides insights on assets that are difficult or costly to inspect; • Monitors load growth and allows for proactive prioritization of capacity availability • Saves operating expenditures and • Reduces planned outage times through proactive cable maintenance		
	Transformer Monitoring	• Real-time transformer monitoring to identify early signs of failure • Provides additional information for diagnostics and future asset management purposes • Enables the data necessary for more granular system forecasting		

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	Network Condition Monitoring & Control (NCMC)	• Reduces flooding-related equipment damage; • Enables the early detection of conditions that can cause vault fires to improve response time and mitigate damage and safety risks; • Provides real-time loading data and remote switching capabilities • Reduces the need for crews to perform inspections	$6.0M	Exhibit 2B, Section E7.3 -Network Condition Monitoring & Control
	Stations Digital Relays	• Accommodates increasingly sophisticated customer needs, including DER integration; • Enables Toronto Hydro to operate its system more efficiently by increasing observability and controllability; • Allows for fault recording for historical view of issues; • Provides relay diagnostics for easier maintenance; • Improves fault coordination	$48.9M	Exhibit 2B, Section E6.6 - Stations Renewal Narrative
	AMI 2.0	• Contributes to reliability objectives by enabling dispatchers to more effectively direct field crews due to last gasp capabilities. • Improves response time for emergency response and outage restoration activities that require customer level outage information • Improves the cost-effectiveness of planning and operational decision-making • Increases visibility into the distribution system particularly at the edge of the grid • Enhances load forecasting and future demand forecast at secondary transformer level using more granular data • Enables more accurate residential load profiles to support efficient resource allocation	$248.1M	Exhibit 2B, Section E5.4 -Metering Narrative

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Controllability & Automation	SCADA Switches	• Reduces fault isolation times on targeted feeder trunks • Reduces average duration of outages for targeted feeders by installing SCADA-enabled tie and sectionalizing points • Reduces the duration of sustained interruptions; • Reduces the time to locate and clear faults; • Enables technologies such as FLISR	$132.9M	Exhibit 2B, Section E7.1 - System Enhancement
	Reclosers	• Reduces the time to locate and clear faults • Reduces the number of customers impacted on a feeder outage • Increases grid efficiency by differentiating between temporary and sustained faults • Enhances observability since reclosers are equipped with advanced monitoring capabilities • Improves reliability upstream of device		
	FLISR	• Improves reliability by quickly detecting and isolating fault, minimizing number of affected customers and reducing outage durations • Improves resiliency to faults and disruptions by minimizing the impact of incidents thereby improving overall grid resilience (such as customers affected during outage resulting in reduced economic losses for customers and businesses)	$34.2M	Exhibit 2B, Section E8.4 - IT/OT Systems

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	ADMS	• Improves grid reliability, reduces outage durations, enhances efficiency and increases customer satisfaction through consolidation of intelligent-device data for increased situational awareness and state estimation • Enhances outage restoration by providing real time situational awareness, automating FLISR workflows and facilitating increased coordination between field crew and control centre • Increases data analysis for data-driven decision making, optimizing grid operations, enhancing system reliability, optimizing asset utilization and identifying energy conservation opportunities		

D5.2.1.4 Intelligent Grid Track Record

Toronto Hydro has a proven track record of effectively implementing Intelligent Grid initiatives and realizing key benefits for customers. This section highlights two major examples of Intelligent Grid accomplishments from recent years: Network Condition Monitoring & Control and Contingency Enhancement.

1. Network Condition Monitoring & Control

Toronto Hydro developed and implemented its NCMC ("Network Condition Monitoring and Control") program in order to increase situational awareness on the low voltage secondary distribution network, with the objective of improving system reliability, environmental performance, and operational efficiency of the network. As discussed in the program evidence (Section E7.3), the NCMC program, which was launched in the latter part of the 2015-2019 period, has represented Toronto Hydro's first full-scale implementation of a new set of distributed grid technologies since the roll-out of the first generation of smart meters in 2006-2008. Toronto Hydro believes that the lessons learned, skills developed, organizational capacity gained, and customer benefits realized through this experience will prove foundational to the successful and efficient implementation of the Intelligent Grid roadmap for 2025-2029.

Toronto Hydro plans to complete the initial scope of the NCMC program by 2026, after which the utility will begin to pilot additional capabilities that could be added to network vaults in the future. As of the end of 2022, the utility has completed over a third of the program and achieved the following benefits from enhanced observability (i.e. water level sensors, vault and transformer operating temperature sensors, oil level and tank pressure sensors, and real-time loading data) and controllability (i.e. remote switching) within its network vaults:

- Over the last two years, the utility has responded to:
  - 56 **water level alarms**, helping to prevent potentially catastrophic vault flooding
  - **temperature alarms** in 14 vaults, allowing for pre-emptive response to potentially catastrophic failures
  - 34 **low oil alarms,** which have helped Toronto Hydro substantially reduce the incidence of high-volume oil spills (see Figure 3 in Section E7.3).

- In the second half of 2022, Toronto Hydro saved approximately $79,000 in operating costs by **remotely checking protectors** (e.g. after heavy rainfall events) in commissioned vaults rather than sending trucks and crews.

- In the first half of 2023, Toronto Hydro has saved approximately $120,000 through the **reduced need to deploy crews to vaults during switching events.**

- In the last two years, **real-time loading data** from commissioned network units was used by controllers during multiple contingency events to determine accurate loading conditions and improve operating decisions:
    - In January 2022, a fire in a cable chamber was caused by the network's secondary cables. Loading analysis was required to determine if a widespread outage on the Windsor network would be required. Controllers used real-time loading data as the input and determined that it was possible to support a multiple contingency event to isolate the affected area without resulting in a large outage on the network.
    - In February 2022, a fault occurred on the Cecil network which supplies highly sensitive customers such as banks and hospitals. Using the NCMC real-time data allowed the crews to identify the fault and re-energize the network in an hour. In addition, NCMC capabilities allowed Toronto Hydro to confirm that the network was able to operate on second contingency and avoid taking the network down completely.
    - In February 2023, a feeder on the George and Duke network experienced a cable fault and a neighbouring feeder tripped shortly after, causing the need for an N-2 assessment. The use of real-time loading data determined that the multiple contingency event could be supported on the network.

- Real-time loading also helps support planned work in addition to failures. Historically, when real-time loading data was not available, Toronto Hydro could not schedule an outage on multiple feeders and vaults simultaneously for planned work, as the specific impact to the network would not be known or definitive. For example, in April 2022, the Cecil network was assessed and confirmed through loading data that multiple feeders and vaults could be taken out of service to support planned work. This allowed the planned work to be scheduled on time.

- As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027.

Toronto Hydro expects these benefits to scale as program implementation continues through 2023-2025. For more information on the progress and benefits of NCMC, refer to Section E7.3.

2. Contingency Enhancement (Horseshoe System Controllability)

Toronto Hydro has been steadily modernizing its Horseshoe distribution system for many years through both its System Renewal efforts and complimentary System Service programs including the Contingency Enhancement segment (Section E7.1). A primary focus of these efforts has been the deployment of SCADA-operated switches which allow control room operators to remotely transfer load and isolate feeder sections under fault conditions or on a planned basis. Figure 4 below shows the number of switches Toronto Hydro has installed per year since 2005. [9]

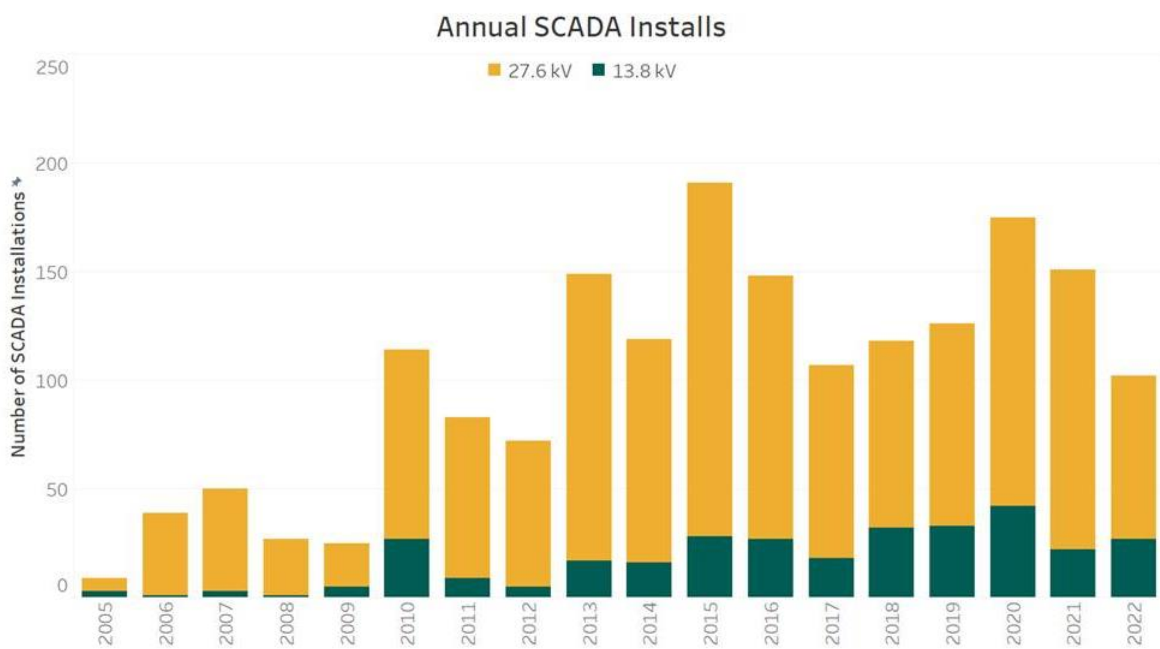


Figure 4. Annual SCADA Switch Installations (2005-2022)

[9] This graph represents all SCADA installations throughout the system, including those not installed through the Contingency Enhancement program.

As discussed in Section E7.1.3.1, these investments have been an important contributor to Toronto Hydro's improving reliability performance over the last decade. Adding SCADA switches (which includes replacing old manual switches with SCADA switches) on a feeder has also had other benefits, including avoided truck rolls and reduced outage restoration efforts in certain contingency scenarios, and reduction of safety risks by reducing the need for manual switching.

As discussed above, these existing switches, combined with the switches and reclosers to be installed throught2023 to2029, will form the physical basis for Toronto Hydro's self-healing grid in 2030 and beyond. Once implemented, Toronto Hydro expects self-healing grid capabilities to deliver significant additional value from these field devices in the form of substantial incremental reliability improvements.

D5.2.2 Grid Readiness

With advancements in technology and the societal imperative to decarbonize the energy system, Toronto Hydro expects the market for DER adoption to continue to mature and expand, likely at an accelerating pace. In response, the utility is planning for a scenario of rapid growth for various types of distributed resources and technologies, including rooftop solar systems, behind-the-meter battery storage systems, and demand response technologies. However, the utility's ability to integrate DG ("Distributed Generation") at pace with planning scenarios is challenged by (i) the precisely calibrated protection schemes potentially mis-operating, compromising the ability of the grid to operate safely and reliably; and (ii) lack of effective tools to analyze and enable interconnection as applications become increasingly complex. If projects materialize and they are integrated well, DG, and more broadly DERs, can play a role in shifting reliance away from the bulk system, supporting an adaptable and resilient distribution network, and empowering consumers to actively participate in the energy ecosystem and clean energy transition.

As the rate of DER uptake increases, it is essential for Toronto Hydro to reinforce the grid to effectively accommodate and integrate these technologies. To this end, Toronto Hydro's Grid Readiness portfolio, illustrated in Figure 5, is dedicated to enhancing what the utility views as the four critical functions of the DER enablement cycle: facilitating, leveraging, monitoring and forecasting, and innovating.

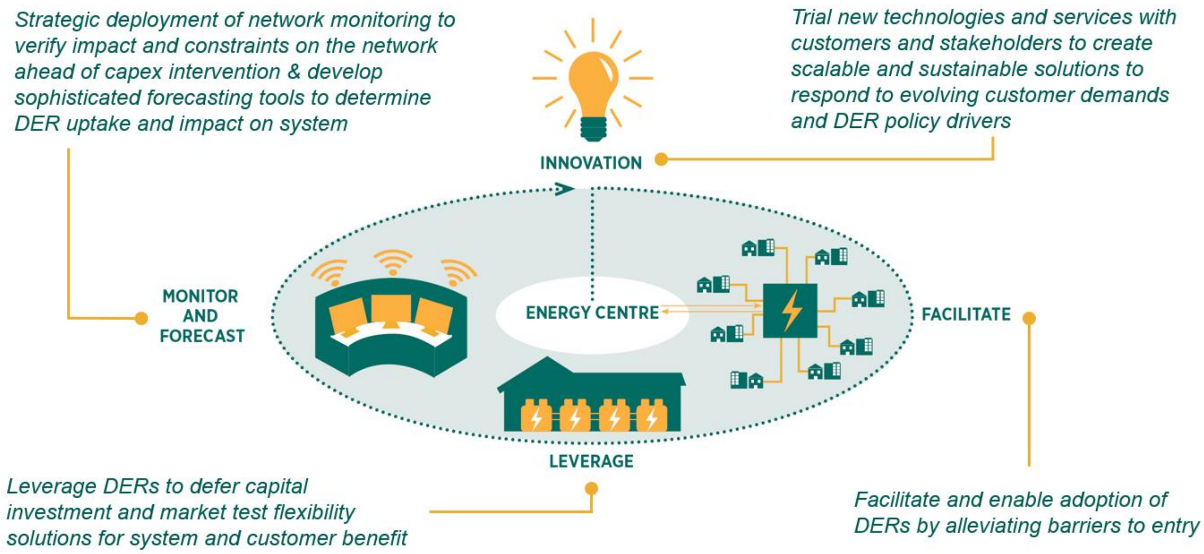


Figure 5: Major Components of the Grid Readiness Strategy

Toronto Hydro has grouped Monitoring and Forecasting together to establish the following three capability domains within the Grid Readiness portfolio:

- **Facilitating DER Connections** entails alleviating DER connection constraints on the grid where feasible and simplifying the process for customers and stakeholders seeking to connect their DERs to the grid. By improving the connection process and providing accessible, high quality geospatial data, Toronto Hydro aims to remove barriers to DER uptake and deliver an end-to-end high-quality customer journey.
- **Leveraging DER Connections** entails harnessing the capabilities of connected DERs to enhance grid flexibility and reliability, and supporting demand response programs in pursuit of grid optimization. Leveraging the inherent flexibility and capabilities of DERs means Toronto Hydro can address the changing dynamics of the grid, adapt to evolving customer needs, and build resilient energy infrastructure for the future.
- **Monitoring and Forecasting DER Connections** entails positioning Toronto Hydro to anticipate, analyze, and manage the impacts of DERs on the grid along various relevant timescales and at the necessary levels of granularity, thereby giving the utility the greatest

chance at successfully building for, and optimizing the utilization of, DERs on its system over the long-term.

Progress in these three domains will also be supported in 2025-2029 by an **Innovation program**, which is summarized in Section D5.2.2.4.

Overall, the strategy in these four critical functions is to continue in the direction of adapting and transforming today's grid into a future-ready smart and flexible grid that, by 2030, is not only prepared to cost-effectively accommodate the accelerating growth of DERs, but also is able to take advantage of the broader potential of DERs to enhance system efficiency, reliability, adaptability, and sustainability for all customers. Failure to pursue these capabilities and innovations in 2025-2029 risks positioning Toronto Hydro as an unwelcome barrier to the potential for widespread DER adoption in the City of Toronto.

D5.2.2.1 Facilitating DER Connections

Toronto Hydro is forecasting a nearly 70 percent increase in connected DER capacity by the end of 2029, though that figure could be higher or lower depending on how potential drivers of DER uptake (e.g. government policy) align to encourage and support a faster uptake.[10] Longer-term, Toronto Hydro's Future Energy Scenarios study projects that the amount of renewable distributed generation and battery storage capacity connected to the grid could grow by as much as 540 percent by 2035 under the "High" scenario and as much as 1,350 percent by 2050, as shown in Figure 6**Error! Reference source not found.**[11,12]

[10] Refer to Exhibit 2B, Section E3 for a comprehensive discussion of forecasted DER connections in 2025-2029.
[11] Renewables in the FES study largely consist of rooftop and ground-mounted solar
[12] Refer to Exhibit 2B, Appendix E for a detailed explanation of policy drivers for each of the scenarios

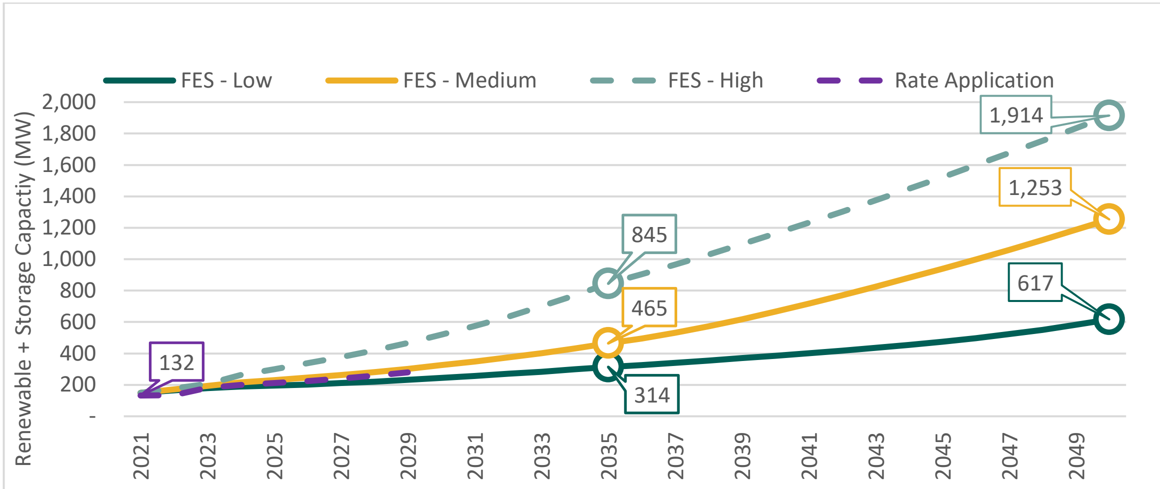


Figure 6: Future Energy Scenarios Renewable + Storage DER Connected Capacity Projections (in MW)

As discussed in detail in Exhibit 2B, Section E3, there are a number of safety and reliability constraints limiting Toronto Hydro's ability to connect DERs, including short circuit capacity, thermal limits, anti-islanding measures, and the ability to transfer loads between feeders in the event of a contingency. While these technical limitations are not widespread on Toronto Hydro's system today, the pace of DER adoption contemplated in the energy transition could lead to pervasive challenges that would make it necessary for the utility to turn away increasing volumes of connection applications.

With this context in mind, Toronto Hydro is planning a number of proactive investments and initiatives that are grouped under the Facilitating DER Connections domain of its Grid Modernization Strategy. These initiatives are intended to achieve the following strategic outcomes:

1. Simplify the process for customers and contractors seeking to connect DERs to the grid;
2. Develop tools to help customers and clean technology investors identify efficient locations to install DERs on the grid;
3. Equip Toronto Hydro with high quality data to anticipate, analyze, and assess DER applications; and
4. Alleviate technical barriers to connecting DERs by investing in additional hosting capacity.

Customers looking to connect DG and ESS ("Energy Storage Systems") require access to the distribution system, which is facilitated through a DER interconnection application; the utility is obligated to enable and connect DERs under Section 6.2 of the DSC ("Distribution System Code") in a timely manner. Toronto Hydro is committed to providing and maintaining high quality customer service from end-to-end of the interconnection journey through the creation of a **Customer Connections Portal** to centralize all requests and provide a one-window seamless and consistent experience. Creating a single, accessible source for customers and staff alike provides the ability to offer reliable connection quotes in a timely manner.

As connection request volumes increase and the system becomes more saturated with DERs, Toronto Hydro expects that the complexity of these requests will similarly increase due to the need to balance current and future requirements of both existing and future DER owners. Eventually, the utility will begin to face limitations on its ability to cost-effectively accommodate new DERs in specific locations on the grid. Toronto Hydro believes that an important role for the utility in this emerging landscape will be to equip customers with easily accessible, accurate, and up-to-date information as to where in the service territory DERs can be accommodated most efficiently, and where it may not be possible or cost-effective to connect new DERs. To accomplish this, Toronto Hydro is committed to developing the capabilities required to display a **Hosting and Load Capacity Map** (or equivalent data portal) which will provide estimated available capacity for DER interconnection and load capacity at different locations on the network based on an automated hosting and load capacity analysis. Visualization of available capacity will provide a two-fold advantage to both the utility and its customers: the utility planners will be better informed to evaluate incoming applications and devise future system upgrade investments, and customers will be better informed to understand the cost complexity of current applications and strategize future DER project investments.

Toronto Hydro expects that the two initiatives above will only make large amounts of DER interconnections possible if data flow from the end-to-end journey is seamless and of high quality to aid grid operation and business decisions. To that end, the **Geospatial Information System (GIS) DER Asset Tracking** initiative will bind the DER visualization and interconnection process journey by streamlining the data management and flows across the different platforms associated with the journey to provide comprehensive records that unlock value in various business functions including DER-related product and service offerings and high-fidelity engineering, planning, and forecasting models.

Finally, in addition to streamlining processes and publishing hosting capacity data, Toronto Hydro will, where necessary, feasible and cost-effective, continue to invest in infrastructure and field technologies which can help alleviate DER connection constraints (i.e. hosting capacity constraints) on its grid. This includes the demand-driven **Generation Protection, Monitoring and Control** program (Exhibit 2B, Section E5.5), which involves installing monitoring and control technology at DER sites and exploring a range of additional options including bus-tie reactors at transmission stations to relieve short-circuit capacity constraints. This also includes a renewable-enabling focus for the utility's **Energy Storage Systems** segment (Exhibit 2B, Section E7.2.2), where battery storage systems will be installed on feeders where power quality and minimum load-to-generation ratios have exceeded 3:1.

In summary, the Facilitating DER Connections capability domain will be primarily addressed through the following initiatives, which are further summarized in Section D5.2.2.4:

1. Enhancing DER Connection Process
2. Hosting Capacity Map
3. GIS DER Asset Tracking
4. Generation Protection, Monitoring & Control (Exhibit 2B Section E5.5)
5. Renewable Enabling Battery Energy Storage Systems (Exhibit 2B Section E7.2)

D5.2.2.2 Leveraging DER Connections

The growth in grid-connected DERs comes with opportunities for utilities to leverage them for grid services and improved grid reliability and resiliency. Utilities across North America are building capabilities to utilize DERs to achieve benefits such as demand response. As the adoption of DERs continues to accelerate across Toronto, it brings opportunities for the utility to move from "walking" with DERs – by approving and enabling their connection – to "jogging" with DERs and unlocking further value in their ability to actively support reliable grid operation as qualified alternatives to traditional infrastructure investments.[13] In 2025-2029, Toronto Hydro plans to expand its use of distributed resources for demand response purposes (i.e. flexibility services) and expand its capabilities to monitor, control and dispatch DERs through a centralized platform.

Toronto Hydro has forecasted a number of capacity constraints emerging on a number of stations on the network in the short-to-medium term. The utility has previously explored LDR ("Local Demand Response") in the 2015-2019 rate period in the Cecil TS ("Transformer Station") area, and expanded this into the Manby TS and Horner TS areas in 2020-2024. The success set the stage for Toronto Hydro to build on LDR into a **Flexibility Services program**, to procure flexibility from customers and

[13] Adapted from Gridworks' Walk-Jog-Run Distribution Grid Planning Framework

aggregators to meet distribution system needs (for a comprehensive discussion of the Flexibility Services program, including accomplishments and enhancements in the 2020-2024 rate period, refer to Section E7.2.1). The program intends to leverage customer-owned flexible assets to provide the utility with new tools for managing and prioritizing capacity constraints that are present and will continue to emerge from the electrification and digitalization of various sectors and communities within this city. The program will also provide customers with new revenue mechanisms and opportunities to engage with their distribution company. Toronto Hydro expects this program will continue to grow and evolve in 2025-2029 as the utility accelerates its journey toward leveraging DERs in real-time and at scale, which will be necessary to navigate the energy transition effectively and efficiently for customers.

As discussed in the Facilitating DER Connections section above, Toronto Hydro also plans to continue deploying ESS in front of the meter, with a primary focus on leveraging ESS to alleviate certain real-time conditions that can prevent Toronto Hydro from connecting customer-owned DERs. Between the ESS and the Flexibility Services programs, the need for technology that can support adequate management of bi-directional distribution grid flows will be increasingly essential. Currently Toronto Hydro manually operates Toronto Hydro-owned DERs and manages them through vendor-specific platforms. As DER penetration increases, the utility's DERMS platform will require a **centralized dispatching and scheduling** module implemented to efficiently manage and operate the volume. Through this centralized platform, Toronto Hydro will be better equipped to plan future utility-owned ESS connections for peak shaving, and offer flexibility services with automated dispatch of demand response.

This capability domain will be primarily addressed through the key initiatives listed below, which are summarized in Section D5.2.2.4 and full details available in the Appendix.

1. Flexibility Services (Exhibit 2B Section E7.2)
2. Energy Center Enhancement for Leveraging DERs

D5.2.2.3 Monitoring and Forecasting

Once DERs are connected at high volumes, they can contribute to grid instability; operating the grid in real-time with larger volumes of DERs proves to be a greater challenge, coupled with fewer options to act when conditions suddenly change. Therefore, establishing the necessary monitoring and forecasting capabilities for DERs will be a crucial component of Toronto Hydro's Grid Readiness portfolio.

One of the largest initiatives that Toronto Hydro is undertaking which could significantly improve monitoring capabilities for DERs is the roll-out of **AMI 2.0**, which is discussed in detail in Section D5.3.1. AMI 2.0 is closely tied to both the Intelligent Grid and Grid Readiness portfolios as it allows the utility to monitor the behaviour of behind-the-meter technologies. Similarly, data that will be obtained through the GIS DER Asset Tracking, FLISR, AMI 2.0, and sensors initiatives will be integrated within the utility's **DERMS** platform to improve on the existing monitoring and forecasting modules available on the platform. Toronto Hydro envisions that the wealth of new data obtained will augment two core operational functions: state estimation and load and generation forecasts to identify and develop better planning decisions through conventional and Non-Wires Solutions methods and share information with IESO for more accurate information to create bulk supply and demand decisions.

Finally, to ensure Toronto Hydro is equipped with the intelligence necessary to plan long-term expansions of the grid and to engage in long-term procurements for flexibility services, the utility must continue to invest in accurate and geospatially granular long-term technology adoption and demand forecasts and scenarios. As discussed in Section 2B Exhibit D4.4.5, for its 2025-2029 investment planning cycle, Toronto Hydro invested in an Ontario-leading **FES ("Future Energy Scenarios")** model to project installed capacity for various technologies including DERs looking out to 2050 to better understand potential impacts on overall system demands. This initial modelling exercise provided net demand impacts at the level of station bus pairs. As a next step, Toronto Hydro intends to explore options for increasing the granularity of these scenarios, including by introducing feeder and/or supply-point (e.g. distribution transformer) impacts, which will provide the details necessary to plan increasingly targeted investments to support local DER integration and consumer electrification patterns.

The capability domain will be primarily addressed through the following initiatives, which are summarized in Section D5.2.2.4 and full details available in the Appendix:

- AMI 2.0
- Energy Centre Enhancements
- Low Voltage Level Forecasting

D5.2.2.4 Grid Readiness Program Summary

The Grid Readiness technologies introduced above are summarized in Table 3 below. For more detail on each technology, please refer to the Investment Program column. For each technology, more detail has been provided in the appendices of this strategy.

Table 3. Grid Readiness Program Summaries

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Facilitating DER Connections	Enhancing DER Connection Process	Customer web portal to manage the end-to-end DER interconnection process. Portal will allow customers and/or contractors to review, submit, track, and if necessary cancel their DER interconnection applications in a single platform. Portal can also allow Toronto Hydro to semi-automate request handling and change orders for approvals and handovers between internal teams.	Toronto Hydro is expected to face non-linear growth in DER interconnection applications, which would contribute to overall evaluation and processing times. Current process methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants, which will challenge Toronto Hydro's ability to deliver within its current lead times.	• Increased ability to handle application volume • Reduction in costs owing to labour hours attributed to manual data entry and tracking and processing applications; • Consolidated and transparent communication channels providing timely application updates to customers • Reduction in data entry errors and faster customer notifications if further or corrected data is required	$2M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Hosting and Load Capacity Map	Interactive web map and/or data portal enabling customers to view available DER hosting and load capacity prior to applying. Map will be built upon a hosting and load capacity analysis conducted on part or all of the distribution grid at the feeder level.	Toronto Hydro historically performs studies and analyses to identify the feasibility of DER interconnection requests on an application by application method, which is time-consuming and resource intensive. Rising volumes of applications will challenge Toronto Hydro's ability to deliver within its current lead times. Furthermore, the overall success rate and efficiency of DER connections can be improved by providing actionable information to prospective applicants.	• Increased visibility into the available capacity of the grid to host DERs • Integration with customer connections portal to update available capacity based on DERs awaiting install • Increased visibility of system nodes with immediate or near-term capacity constraints • Reduction in dependency on "general guidelines" within technical screens with insight into the required depth and analytical rigour to process applications	$1M	IT/OT Systems (Exhibit 2B, Section E8.4)
	GIS DER Asset Tracking	Streamlined data management and data flows across the different platforms associated with DER interconnection requests (connections portal, Geographic Information System ("GIS"), Energy Centre) to enhance visualization and control capabilities of DERs.	Toronto Hydro currently relies on manual data entry to transfer DER asset data records between platforms. This causes process inefficiencies and issues with data quality. Transferring GIS onto the Energy Centre backend requires manual routine updates which hinders Toronto Hydro's ability to develop more advanced applications of Non-Wire Solution program concepts. Generally, advanced smart grid capabilities are highly dependent on data quality and systems integration.	• Robust organization of DER interconnection data from application submission through to installation and commissioning • Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms • Increased efficiency of data transfer through integration of data from DER platforms without the need for manual effort in syncing data	$1.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Grid Protection, Monitoring and Control	Installation of bus-tie reactors and exploration of other technologies to alleviate short circuit capacity constraints at select stations and Monitoring and Control Systems (MCS) for renewable DERs to prevent anti-islanding concerns and support system capability to connect and control distributed generation.	Toronto Hydro has identified and forecasted a number of stations with short circuit capacity limits, capping the amount of DER connections. Additionally, several feeder circuits have surpassed the recommended generation to minimum load ratio, increasing the amount of time required by inverters to respond to anti-islanding scenarios and decreasing the likelihood of inverters responding to anti-islanding scenarios.	• Remote and automated isolation of DER connections under specified conditions • Ensures operation of the distribution network within safe and allowable short circuit current limits • Avoids unintentional islanding and reducing the islanding risk of DER sources • Increased ability to observe large DERs in real-time to enable the maximum allowable amount of connected distributed generation	$35.0M	Grid Protection, Monitoring & Control (Exhibit 2B, Section E5.5)
	Renewable Enabling Energy Storage Systems (“ESS”)	Deployment of grid-side battery ESS with a primary focus on managing and alleviating constraints against connecting customer-owned renewable energy generation facilities. This can be accomplished by operating ESS as a load on feeders with high generation and low load demand. As a secondary matter, the utility will also continue to explore other grid supporting use cases for distributed, front-of-the-meter ESS.	Integration of renewable energy sources such as solar require a reliable and flexible solution to address the potential of grid instability and to enable integration of high levels of renewable energy.	• Increased peak load management • Improving overall power quality by resolving load-balancing on feeders with MLGR issues • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions	$22.5M	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Leveraging DER Connections	Flexibility Services	Programmatic approach to address localized distribution issues through targeted procurement of demand response (i.e. peak shaving) services from owners of DERs and flexible loads.	Increased electrification will require Toronto Hydro to identify short-to-medium term capacity constraint-releasing methods alongside the more traditional "poles and wires" approach investment strategy.	• Improved reliability through demand congestion management • Deferred (or avoided) capital investments where demand is uncertain • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions • Increased customer engagement and participation through revenue-based mechanisms	$5.7M (OPEX)	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)
	Energy Centre Enhancement for Leveraging DERs	Implementation of the Advanced Scheduling and Dispatch module within Energy Centre (DERMS) to (i) enable real-time control and management between storage management systems and (ii) augment the Flexibility Services program.	Currently existing Toronto Hydro owned DER assets are manually operated and/or managed through vendor-specific platforms. This operational method will become unsustainable without a centralized dispatching and scheduling platform to optimize coordination of assets and participation in Flexibility Services programs.	• Enhanced integration of energy storage projects • Improved resource utilization of DERs • Improved coordination of DER dispatch and scheduling on one platform	$150K (OPEX)	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Monitoring & Forecasting DER Connections	AMI 2.0 for DER Monitoring	Deployment of next-generation smart meters in 2025-2029. These meters will provide new and enhanced forms of telemetry at the customer supply point, including data that will be relevant to monitoring and managing the impacts of DERs and electrified consumer technologies (e.g. EVs). Toronto Hydro will explore use cases from this data to inform the next phase of the DER monitoring and control strategy in 2030.	As DER penetration increases, the variability in household level voltage will require more fine-tuned DER monitoring and management to anticipate and address situations such as voltage violations and overloading.	• Improved observability of customer level loads and voltages • Increased capability of current and future flexibility service programs • Optimize DER dispatch to address grid conditions in local areas • Enhanced baseline data for use in developing long-term investment planning forecasts and other decision-making analytics	$248.1M (Total Revenue Meter replacement cost in 2025-2029)	Metering Program (Exhibit 2B, Section E5.4)
	Energy Centre Enhancement for Monitoring and Forecasting	The implementation of other Grid Modernization initiatives creates more powerful monitoring and forecasting capabilities within DERMS/Energy Centre to identify and act on any operational issues, deviations from expected performance, or potential grid constraints caused by DERs. Integration of more granular data into Energy Centre can build on DER disaggregation and day ahead local forecasting capabilities to broaden flexibility services and	DER penetration requires monitoring and forecasting capabilities to understand the impact the assets will have on the grid due to the bi-directional power flow introduced onto the network.	• Improved ability to coordinate with IESO (bulk supply and demand planning) • Improved load and generation forecasting abilities • Enhanced monitoring of DERs to identify possible voltage fluctuations • Increased visibility of DERs through disaggregation display (e.g. regions, area, transformers) for future Non-Wires Solutions program locations	$2.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
		energy storage programs as they develop.				

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Low Voltage Level Forecasting	Future Energy Scenarios (FES) provides an overview of possible future changes to power demand, energy consumption, generation, and storage across the City of Toronto with an assessment of their potential impacts on the distribution network. The scenarios are predicated upon a granular, consumer choice-based analysis of future loading conditions at the desired modelling level. In 2025-2029, Toronto Hydro will consider options for enhancing the geospatial granularity of this model to support targeted, local investment planning and various other value streams related to electrification and the energy transition. This will require incremental investment in modelling capacity.	Population growth and increased electrification to support the energy transition to Net Zero represents an increasing level of uncertainty due to the many different economic and policy conditions that can alter the anticipated level of electrification. A strategic framework and methodology are required to inform and support network planning and future infrastructure investments. While Toronto Hydro can presently model these factors at the station bus level, it is necessary to enhance the model granularity to provide better insight into how electrification and DERs could impact the system at the low-voltage level (i.e. feeder and neighbourhood level).	• Standardized strategic outlook of different drivers of change to support needs across different Toronto Hydro business functions as well as planning consultations with customers and stakeholders • Increased insight for planners into the potential geospatial distribution of electrification on the network and technologies representing the make-up • Optimized decision making for investment planning at the feeder level with real-time data from the system observability program to confirm and adjust future forecasting	Initiative will be funded as a Software Enhancement (Estimate TBD)	IT/OT Systems (Exhibit 2B, Section E8.4)

1

D5.2.2.5 Grid Readiness Track Record

Over the last decade, Toronto Hydro has strived to be a leader in Ontario when it comes to exploring and implementing technologies and solutions for facilitating, leveraging, monitoring and forecasting DG and DERs more broadly. The following are some major highlights from recent years.

1. Electric Vehicle ("EV") Smart Charging Pilot

Toronto Hydro partnered with Plug'n Drive and Elocity Technologies to trial an EV Smart Charging Pilot aimed at understanding EV charging patterns and behaviours in Toronto and gathering information to assist in the development of future EV programs to support current EV drivers and those wishing to switch over to an EV. Benefits of this pilot include supporting the development of additional tools for EV owners to monitor, schedule, and control their charging sessions, and collecting data and insights to understand impacts of EV charging on the distribution grid.

2. Non-Wires Solutions

Toronto Hydro has been a leader in the procurement of demand response services from customers. The utility's Local Demand Response program (LDR) was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program was designed to help address short-to-medium-term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively. In the 2015-2019 rate period, Toronto Hydro successfully used LDR to reduce summer peak demand at Cecil TS by about 8 MW, helping to avoid anticipated capital investment. In the 2020-2024 period, the utility has been pursuing similar DR services in the areas of Manby TS and Horner TS, and, through the OEB Grid Innovation Fund and Innovation Sandbox program, is working with the IESO, Power Advisory, and Toronto Metropolitan University's Centre for Urban Energy to implement a Benefit Stacking Pilot, which will trial an auction mechanism to procure DR resources to provide local system service, and aggregate these resources to offer their capacity into the IESO wholesale market. In 2025-2029, Toronto Hydro is planning to expand its Local Demand Response program into a more diverse Flexibility Services program and procure up to 30 MW of demand response capacity in the Horseshoe North area. For more details on Toronto Hydro's Non-Wires Solutions programs, refer to Section E7.2.

3. DER Integration

Toronto Hydro has a well-established program for DER facilitation and integration, and has been actively supporting DER connections for its residential, commercial, and industrial customers. As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid with a total capacity of 304.9 MW. For more information on Toronto Hydro's experience with, and plans for, connecting and integrating DERs, please refer to Section E3 (Capability for Renewables), E5.1 (Customer Connections), and E5.5 (Grid Protection, Monitoring and Control).

4. BESS ("Battery Energy Storage Systems")

Toronto Hydro has been active in the energy storage space since 2017, with several existing projects completed or underway. The utility has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, a front-of-the-meter BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis;
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure;
- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level; and
- Maintenance of BESS assets.

Toronto Hydro also has experience with behind-the-meter BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (i.e. Metrolinx ECLRT and TTC eBus garages). These projects have also provided valuable experience and have supported the development of various capabilities that will be valuable in deploying, facilitating, monitoring, forecasting, and leveraging BESS going forward. For more details on Toronto Hydro's experience with BESS and the strategy for 2025-2029, please refer to Section E7.2.

5. FES ("Future Energy Scenarios")

To support preparation of the 2025-2029 Distribution System Plan, and in recognition of the growing uncertainty with respect to future load growth and DER adoption rates, Toronto Hydro commissioned the province's first Future Energy Scenarios model and report to provide a detailed overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the electricity distribution network. This project was a major step forward in the utility's development of a more robust long-term strategic grid planning function and was essential to the adoption of a "least regrets" approach to capacity planning for the 2025-2029 period, which is discussed in detail in Section D4. Going forward, Toronto Hydro intends to explore opportunities to further enhance its demand forecasts and scenario analyses, including by investing in more granular geospatial models which can support improved capacity planning at the neighbourhood level in anticipation of long-term trends in the uptake of technologies such as EVs and heat pumps.

D5.2.2.6 Innovation Program

Progress across all domains of the *Grid Readiness* portfolio (and related elements of the broader Grid Modernization Strategy) will be supported in 2025-2029 by an **Innovation Program**, which will focus on designing and executing targeted innovation projects in collaboration with customers, stakeholders, and technology providers, with the objective of creating scalable and sustainable solutions to enduring or imminently anticipated problems with respect to widespread DER integration and electrification of the energy economy. A robust innovation program will help the utility allocate the funding necessary and create the organizational pathways required to address the novel challenges and opportunities that policy-supported DER proliferation and integration will present to the grid and utility operations over the next decade.

Learnings from all of the innovation pilots will be shared within the industry to foster industry-wide collaboration and reduce innovation risks. Where the pilot is successful, Toronto Hydro aims to scale the solution and roll it into existing business practices to provide rate payers benefits.

There are a number of innovation project concepts that Toronto Hydro is considering for the 2025-2029 rate period. Some examples of potential projects are listed below in Table 4, while full descriptions are in Section D5.3.8: Appendix I – Innovation Pilot Projects and Exhibit 1B, Tab 4, Schedule 2, Appendix A..

1 **Table 4. Sample Innovation Pilot Project Summaries**

Pilot Concept	Description	Need	Benefits
Flexible Connections	Explore and develop technological and commercial offerings that could allow customers to more cost-effectively connect distributed generation ("DG") on constrained parts of the grid. A "flexible" connection is one which could be controlled and curtailed in real-time by leveraging smart-grid technologies controlled by the utility. This could be achieved through development of an advanced Energy Centre (DERMS) system coupled with intelligent device installation utilized through a communications platform.	Integrating DG into the distribution network poses several technical constraints (e.g. voltage violations) if not proactively managed and coordinated. DG customers looking to connect on constrained parts of the network may be prevented from connecting, or could faced high costs and long lead times because of the need for system upgrades. Allowing Toronto Hydro to control the customer's DG output in automated coordination with critical system operating parameters could provide a more cost-effective solution in the future.	• Reduced delays and costs for customers looking to connect DG on parts of the grid approaching thermal and voltage limits • Increased customer engagement through new commercial arrangements • Optimized usage of existing network infrastructure • Improved overall hosting capacity for DERs
EV Commercial Fleet	Examining the impact of commercial EV fleet charging at depots and other charging segments and optimize charging schemes based on the flexibility requirements and preferences of Toronto Hydro and pilot participants.	Widespread adoption of commercial fleet electrification may face high connection costs, creating a barrier to EV adoption, as well as incurring significant distribution system upgrade costs if not managed in coordination with the utility.	• Quantify and minimize the impact of commercial fleet electrification on the grid • Quantify the total cost of ownership for smart scheduling and charging solutions for EV fleets • Identify necessary infrastructure to facilitate fleet transition to EVs

Pilot Concept	Description	Need	Benefits
Electric Vehicle Demand Response	Identify viable demand response models that facilitate coordinated charging and potential discharging of EV batteries to support network needs. An initial pilot project with some customers has been successful in demonstrating load shifting to off-peak times and load deferral by utility-initiated curtailment. Future projects will target a broader set of control technologies that enhance consumer choice and scalability over time.	The shift from combustion engine vehicles to electric poses several potential system challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various system levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously.	• Increased customer participation in new charging mechanisms • Deferred (or avoided) capital investment in station upgrades through smart EV charging management • Quantify EV charging impact on the secondary distribution grid
Advanced Microgrid	Identify viable microgrid topologies within Toronto Hydro's network and trial a microgrid on the distribution system to observe system resiliency in real-time grid conditions.	The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages, which is a consideration for the imperative to electrify the city. This is a particular concern for population segments and services that rely on power for mission-critical needs.	• Quantify commercial viability of community microgrids to improve grid resiliency • Flexible resource to sustain operations during outages • Provide ancillary services to the wider grid • Facilitate new methods of connecting higher penetrations of renewable energy generation

D5.2.3 Asset Analytics & Decision-Making

The *Asset Analytics & Decision-Making* portfolio within the Grid Modernization Strategy covers improvements that Toronto Hydro plans to make in order to more fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. Toronto Hydro possesses large quantities of data, including condition of its assets, the historical performance of its system, and electricity consumption. Through the investments planned within its Intelligent Grid and Grid Readiness portfolios, the utility foresees the accumulation of even more robust datasets over the next decade, including increasing volumes and varieties of real- or near-real-time network and asset conditions and performance data. At the same time, data analytics and automation solutions have emerged within the wider industry, which create opportunities for more effective delivery of traditional value streams for customers (e.g. reliability, safety, cost control) during the energy transition, while also enabling a more dynamic local energy market. This means that the availability of current, high-quality, and readily accessible data sets will graduate from a "nice to have" to "must have" for utility operations. Having the systems and expertise to support more detailed insights will become critical in the years ahead. Therefore, achieving the corresponding level of data quality and analytical rigour will require Toronto Hydro to continue investing in its people, processes, and digital tools.

The *Asset Analytics & Decision-Making* portfolio outlines the strategic focus areas for the advancement of Toronto Hydro's digital asset management capabilities in 2025-2029. The utility's objective is to accelerate progress on the foundational data analytics and decision-making capabilities that will be necessary to manage costs and operate effectively as changes in the energy sector accelerate beginning later this decade and into the 2030s. Toronto Hydro is focused on three main capability domains depicted in Figure 7 below.

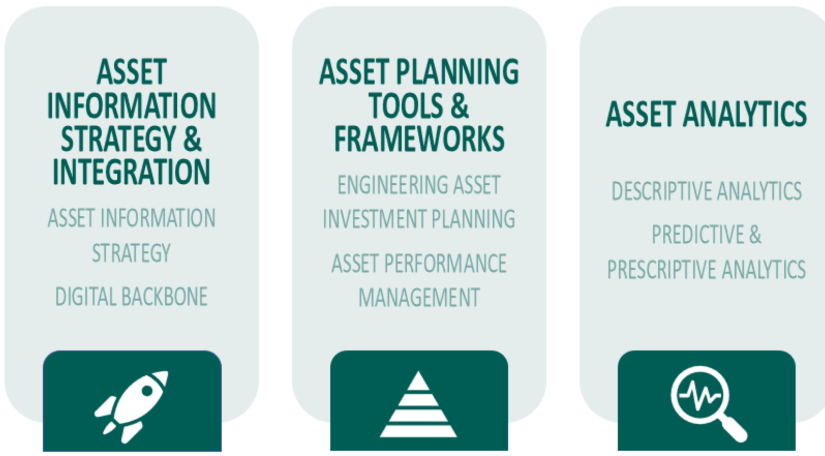


Figure 7: Major Components of the Asset Analytics & Decision-making Portfolio

These domains address the following investment needs:

1. **Asset Information Strategy & Integration:** This domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making the information readily available to business users.
2. **Asset Planning Tools & Frameworks:** This domain involves acquiring or enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's customer-focused investment plan and finding efficiencies within the planning process itself.
3. **Asset Analytics:** This domain focuses on developing new descriptive, predictive, and prescriptive analytical capabilities to drive efficiency and create value throughout the various stages of asset planning and operations.

The following sections provide additional detail on each of these domains. The activities and investments described throughout the Asset Analytics & Decision-Making portfolio will predominantly take the form of information technology projects, which are funded through either the IT/OT Systems Program (Exhibit 2B, Section E8.4) or the Information Technology OM&A program (Exhibit 4, Tab 2, Schedule 17). The incremental activities involved in embedding these solutions within evolving business processes, including implementation management, documentation, training, and administration, will require additional support from analysts, engineers, and various other professionals across the organization.

D5.2.3.1 Asset Information Strategy & Integration

The Asset Information Strategy & Integration domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making it readily available to business users.

As a key part of the effort to modernize the grid and grid operations, distribution utilities like Toronto Hydro will be gathering greater volumes and varieties of data in the next decade, with the intention of leveraging this data to develop value-adding applications and insights, as well as supporting automation of the grid (which in many cases is fundamentally a data-analytics-driven effort). The most important foundational step toward making this level of data-driven operations achievable and sustainable is ensuring that the process begins with a clear and comprehensive **Asset Information Strategy**. As part of its ISO55001 journey, documented in Exhibit 2B, Section D1, Toronto Hydro is currently in the process of creating a consolidated Asset Information Strategy, with the goal of having a clear asset data management strategy that identifies and prioritizes required asset information for current and future applications, outlines asset data quality requirements, assigns data ownership, retention levels, and backup requirements, and establishes change management processes. Toronto Hydro currently has multiple systems (such as GIS and ERP) which it uses for asset information purposes. The Asset Information Strategy and associated information standards will establish a system-agnostic guideline for all of the utility's key asset-related information and provide the basis for integration of relevant systems in order to create a "single source of truth" for critical data which will be stored as a central repository for analytics purposes.

The second foundational step is to proceed with further integration of relevant enterprise systems and additional data sources (such as images captured through maintenance activities) into a fully harmonized asset data registry, or "**digital backbone**" for asset planning and grid strategy. The digital backbone, in the context of this strategy, is the foundation of integrated data sources and systems, and storing those asset data effectively to enable more advancement in asset planning capability. Toronto Hydro has made gradual and targeted progress on this front in recent years, building on the implementation of new data warehousing and blending tools in 2017 to create purpose-built databases that bring asset and system information together for operational reporting and decision-making purposes. However, looking ahead at future demands for higher quality data and analytics, there are opportunities that the utility is aiming to pursue in 2025-2029 through the IT-OT Systems program (Section E8.4). One most significant opportunities involves enhancing asset data analytics by unifying data across major enterprise systems, including the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. Fully and permanently consolidating relevant data in these systems is a significant investment, and there are a variety of possible approaches to achieving the desired end state. Toronto Hydro intends to explore and implement appropriate and cost-effective solutions for further integrating these major databases in 2025-2029, not only because these integrations will be increasingly necessary, but also because the utility anticipates substantial benefits to customers and stakeholders in the form of improved efficiency, analysis, and reporting. For example, high quality data on the condition of assets on the system can improve the timing and level of maintenance performed on those assets, leading to a lower failure risk and improved service for customers. The core features of a digital backbone are summarized in Figure 8 below.

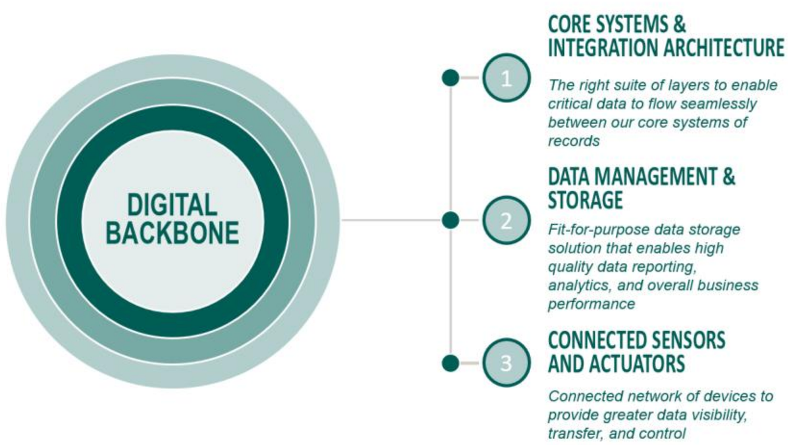


Figure 8: Core Components of a Digital Backbone[14]

[14] McKinsey & Company, Enhancing the Tech Backbone, n https://www.mckinsey.com/industries/industrials-and-electronics/our-insights/enhancing-the-tech-backbone

D5.2.3.2 Asset Planning Tools & Framework

The Asset Planning Tools & Framework domain involves enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's long-term, customer-focused investment plan and finding efficiencies within the planning process itself.

Toronto Hydro has been refining its risk-based asset management framework for many years, with the goal of being an industry leader when it comes to the use of risk inputs such as asset health scores to optimize operating and capital expenditure decisions. Having matured its asset management risk and outcomes frameworks in recent years, the utility has now begun to invest in digital platforms that will bring greater consistency, transparency, sophistication and efficiency to the implementation of these underlying decision-making frameworks within business planning processes. An overview of these future capabilities is summarized in Figure 9.

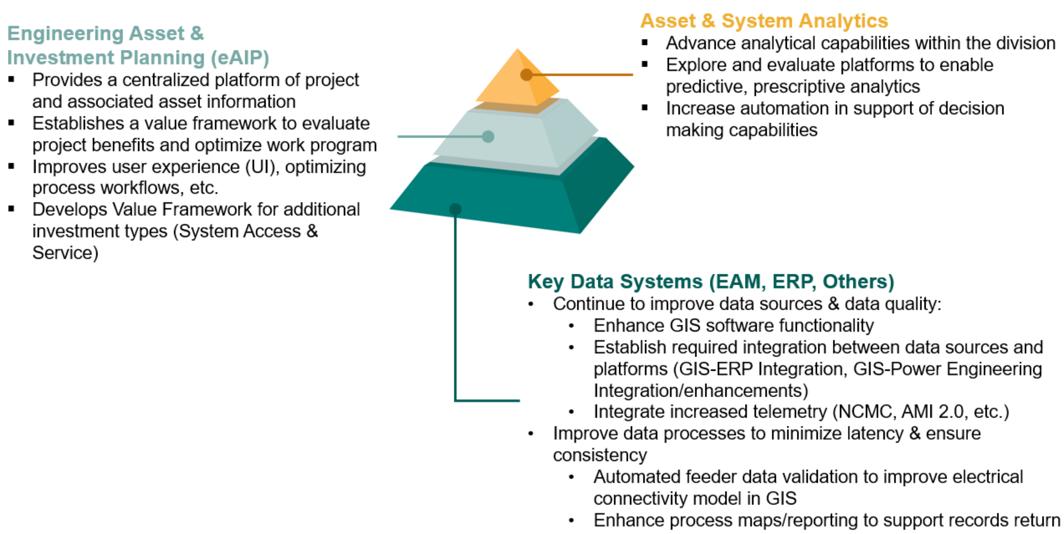


Figure 9: Asset Management Capabilities

As summarized in Section D1.2.1.1, a major element of this effort is the ongoing implementation of Copperleaf C55 as Toronto Hydro's new **Engineering Asset Investment Planning ("EAIP")** solution. At the heart of this tool is a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes, including their contributions to risk-based measures where applicable. This value framework will be leveraged to compare projects within and across programs and to produce value-optimized investment plan recommendations within prescribed funding and operational constraints, ensuring that Toronto Hydro's investment planning decisions are informed by data-driven assessments of costs and benefits in alignment with the utility's outcomes-oriented strategy.

Rather than relying on generic, "off the shelf" framework elements, Toronto Hydro is developing an industry-leading, fully customized value framework for its EAIP implementation, with the goal of ensuring that planners and management are confident in the outputs and recommendations from the tool. Given the customized nature of the implementation, it is an ongoing multi-year effort. Toronto Hydro is currently on track to begin leveraging EAIP's optimization capabilities for the majority of its system investment program by the beginning of the 2025-2029 rate period.

Following on the heels of the EAIP implementation, Toronto Hydro intends to explore and implement further extensions of its risk and value frameworks into other aspects of the decision-making cycle for its assets. For instance, upstream of EAIP is the initial process whereby planners are tasked with identifying suitable capital project candidates, which they then feed into the EAIP system for program management and optimization purposes. Toronto Hydro's goal in 2025-2029 is to extend the logic of its risk and value framework into this earlier step in the process by implementing an asset analytics tool which is capable of algorithmically generating recommended interventions on the system, which Toronto Hydro expects will support greater efficiency in planning by equipping planners with more effective decision-making intelligence. For example, planners will benefit from EAIP as it will reduce manual effort in determining optimized projects for each portfolio segment by an estimated 50 percent (pending implementation insights). This is further discussed in the Asset Analytics section below.

Toronto Hydro also intends to explore **Asset Performance Management ("APM")** applications in 2025-2029. An APM solution is a software tool (or set of tools) that can help an asset-intensive organization optimize the performance of its physical assets throughout their lifecycle by leveraging condition information – especially real-time condition information – to produce analytics that can inform more precise and accurate decision-making. Today, APMs are most commonly deployed by organizations such as manufacturers and power producers, where any production downtime can have a significant financial impact on the business, warranting investment in the creation of a "digital twin" of the plant (i.e. a high-resolution digital replica of the infrastructure) and the deployment of sensors and controls that capture detailed information that can then be leveraged by the analytics engine of the APM to predict and manage plant performance. Due to the highly distributed nature of Toronto Hydro's plant and the general absence of real-time asset condition information, there is not, at present, an obvious business case for implementing a full-scale APM. However, in recent years, Toronto Hydro has deployed real-time sensors in certain parts of the system (e.g. the Network Condition Monitoring and Control Program discussed above in section D5.2.1.4, as well as Exhibit 2B, Section E7.3) and intends to leverage these new telemetry points to explore and pilot the use of APM-like capabilities, with the goal of assessing whether there may be long-term value in these solutions.

In addition to the digital platform solutions discussed in this section, Toronto Hydro remains committed to continuously improving its foundational risk-based decision-making frameworks for its assets. For more details on these efforts, please refer to Section D1 and D3 of the Distribution System Plan.

D5.2.3.3 Asset Analytics

The Asset Analytics domain focuses on developing new, more advanced analytics capabilities to draw insight, drive efficiency and create value throughout the various stages of asset planning and operations. As mentioned in Section D1, Toronto Hydro has been ramping up its efforts to develop a more robust asset analytics function. This effort involves two major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, and (ii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications.

As in many other business sectors, the utility asset management space has become ripe for investment in innovative data analytics. This is due in part to two major factors:

1) The amount of data collected on the distribution system (e.g. condition, loading, and outages) and various correlated external conditions (e.g. weather patterns, consumer behaviours, and third-party geospatial data) has grown exponentially and will continue to do so as digitalization of the industry continues and the utility deploys more smart devices as part of its Grid Modernization Strategy; and

2) The development of advanced analytical tools, algorithms, and computing power and storage have made it easier and more cost-effective to analyze large volumes of data.

In the asset management space, utilities have the opportunity to leverage this data to create new kinds of analytics which could help identify and avoid inefficiencies, and lead to the discovery of opportunities to enhance the performance and value derived from distribution assets, with the eventual goal of having a network that can carry out automated decisions as depicted in Figure 10.

Asset analytics can be broken down into three categories which range in complexity:

(i) *Descriptive (and exploratory) analytics*, which relies on techniques such as data aggregation, data mining, and data visualization, to summarize historical data and provide a clear understanding of what has happened in the past;

(ii) *Predictive analytics*, which relies on techniques including regression analysis, time series analysis, and machine learning algorithms, uses historical data and statistical algorithms to make predictions about future events or trends; and

(iii) *Prescriptive analytics*, which includes techniques such as optimization, simulation, and decision analysis, to not only predict future outcomes but also recommend actions that can be taken to affect those outcomes.

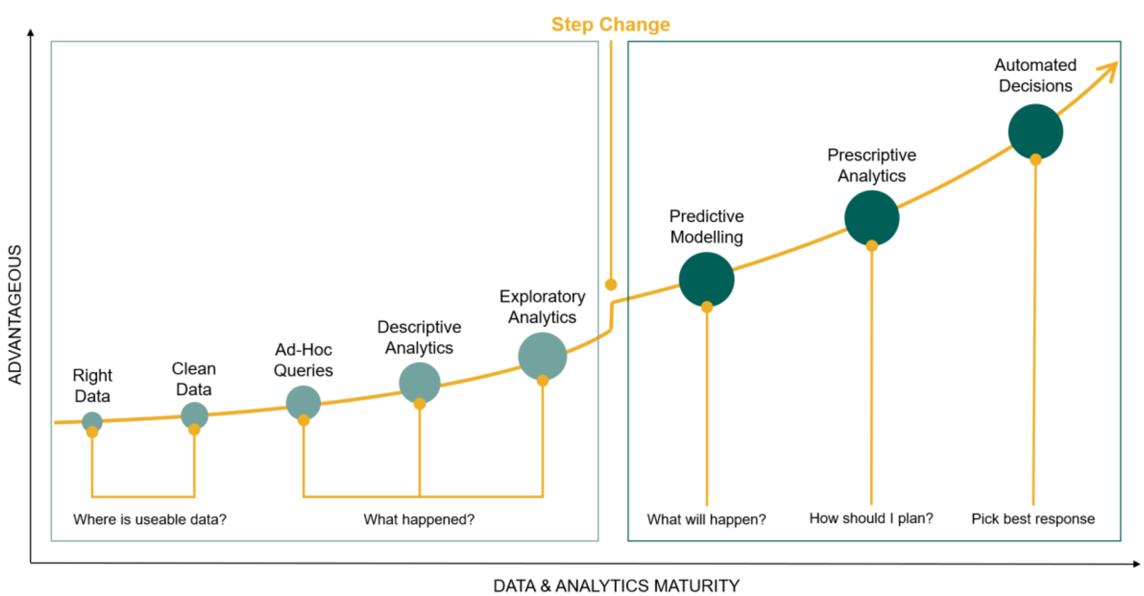


Figure 10 : Analytics Maturity Graph

Toronto Hydro has made strides on all three of these fronts in recent years and is planning to accelerate investment in these areas in the 2025-2029 rate period.

Descriptive Analytics: Since the procurement and implementation of more analytic platforms, such as data warehouse, data blending and visualization platforms in the 2015-2020 period, business units across the Toronto Hydro organization have steadily adopted these tools to enhance business processes and create an array of descriptive analytics. By moving beyond manual data workflows and the limited capabilities of basic visualization tools, Toronto Hydro has made many reporting and decision-making processes more efficient and effective, and this is especially true within the Asset Management parts of the organization. For example, Toronto Hydro leveraged a reporting technology solution to develop workflows in preparing data for analytics, relieving staff of manual data processing to focus on other value-added tasks. In the 2025-2029 rate period, Toronto Hydro's aim is to continue expanding the use of more sophisticated descriptive analytics, with a particular emphasis on investing in more effective geospatial visualization capabilities.

Predictive and Prescriptive Analytics: Toronto Hydro plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations in 2025-2029. The utility is prioritizing several initiatives, including the following:

- As mentioned in the Asset Planning Tools & Frameworks section above, Toronto Hydro is planning to implement an asset analytics engine which will leverage the utility's asset risk data, system topography, and other inputs to predict the future performance of the system with greater granularity and accuracy. The goal is for this analytics engine to also produce optimized recommendations for geographically defined capital projects based on their likely contribution to key value measures and system performance. This solution will complement the work program optimization capabilities within EAIP and complete Toronto Hydro's efforts to inject consistent predictive and prescriptive analytics into all stages of project planning. This will help to ensure the overall costs and benefits of the capital portfolio are optimized from the point of project conception to the point where projects are released for construction within the annual execution work program. Toronto Hydro also expects that these analytics will aid planners, analysts, and senior decision-makers in making planning decisions more efficiently by, for example, combining the functionality of three separate applications in one. Finally, the utility also expects an asset analytics engine to have regulatory benefits as it will support more efficient development of the long-term capital investment plan scenarios and associated risk and performance projections that are required for a five-year Distribution System Plan.

- In preparation for the 2025-2029 investment planning cycle and as a way of complementing the Stations Load Forecast process, Toronto Hydro introduced the Future Energy Scenarios model in 2022. This is a bottom-up, consumer choice model that produced projections under a variety of potential energy system transformation scenarios. Toronto Hydro's goal for the project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on Future Energy Scenarios can be found in Section D4. During the 2025-2029 rate period, Toronto Hydro plans to refine the model with new inputs, as well as develop a more granular level of forecasting to further enhance its investment planning process.

- Toronto Hydro is exploring opportunities to leverage analytics in predictive maintenance for its electric assets as well. For example, the utility is currently running a pilot project that will explore the use of high-resolution satellite imagery and artificial intelligence as a basis for creating a risk-based decision-support tool for the Vegetation Management program. Such a tool would be analogous to the asset-driven analytics engine discussed in the bullet above, insofar as it would leverage AI-driven predictive capabilities to forecast the system impacts of tree contacts at a granular level, while also leveraging predictive insights to recommend feeder-specific tree-trimming cycles and identifying high-risk areas that could benefit from spot trimming.

- More broadly, Toronto Hydro is aiming to take an agile approach in 2025-2029 to exploring and producing homegrown and vendor-supported analytics applications for targeted use cases. For example, the utility's in-house analytics teams have already developed demonstration models for electric vehicle detection leveraging AMI data, computer vision (e.g. using machine learning to identify and classify trip hazards from inspection photos), and data interpolation (e.g. predicting the likely cause of outages classified as "unknowns"). Toronto Hydro foresees numerous value-added use cases for machine learning models and advanced analytics, and plans to develop the resources and vendor partnerships in 2025-2029 that will allow for a more sustained approach to realizing these benefits for customers.

As discussed above and in Sections D1 and D3, Toronto Hydro has a steady track-record of leveraging its analytics tools to create efficiencies and drive innovation across various departments and functions, including most recently the development of models that demonstrate the potential for machine learning to assist in the identification of key trends such as EV adoption on the grid. The following are two additional highlights of the many analytics enhancements achieved in the last five years, specifically in the Maintenance Planning area.

1. Asset Deficiency Automated Prioritization Tool ("ADAPT")

Toronto Hydro has redesigned its priority decision framework through the introduction of ADAPT, a work request prioritization tool that uses an Alteryx workflow to use the deficiencies reported through inspection programs completed by contractors. The workflow takes in inspection reports and assigns priority and corrective actions using a job mapping devised by maintenance planning engineers.

a. __Select benefits:__

- Reduced manual engineering reviews of major assets by 40 percent
- Reduced errors from synchronization of inspection form and personnel changes
- Introduction of single notification that can bundle one or more deficiencies where appropriate, resulting in downstream operational efficiencies

2. Preventative Maintenance Units Tracking Workflow

Toronto Hydro introduced a new workflow centered around translating plant maintenance order statuses from ERP to maintenance unit attainments. This previously was completed through manual data processing and handling.

b. __Select benefits:__

- Reduced approximately 300 hours of labour per year
- Improved accuracy and consistency of data and data-sharing
- Provision of ad-hoc updates and more transparency in workflow changes when required

D5.3 Appendices

D5.3.1 Appendix A – AMI 2.0

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Toronto Hydro was among the first utilities in Ontario to implement smart meters between 2006 and 2008 to support the efficient and effective operation of the distribution system. Primarily, these new meters improved on capabilities such as accuracy in customer billing, account connection/disconnection, and tampering detection. Rapid advancements in technology have made these first-generation meters outdated and obsolete. As the majority of these meters also reach end of useful life in the coming years, Toronto Hydro plans to replace them with next-generation smart meters – AMI 2.0.

AMI 2.0 goes beyond a billing device – the meters represent a network of sensors that provides previously unattainable visibility into performance and behaviour at the edge of the grid. They are equipped with improved hardware that supports data collection intervals up to every 5-15 minutes (and in some cases even more frequently). When this granular data collection is paired with higher bandwidth and shorter latency to improve transmission, the communication of meters expands system observability and can go further with other grid data to provide valuable insights into system operation, energy consumption patterns, and grid performance. AMI 2.0 has the potential to form a significant part of the digital backbone of the grid modernization strategy by improving the visibility and accuracy of data on voltage levels, power flows, and load consumption. These improvements are instrumental in painting a never-before-seen picture of the secondary network; along with sensors installed as part of the System Enhancement program, the utility will gain additional insights into the loading profiles of secondary transformers. Greater visibility means better analytics and decision-making for grid operations, asset management, and investment decisions at the secondary level.

However, fully realizing the modernization benefits that AMI 2.0 can provide is heavily predicated on investments in implementation and maintenance of the IT infrastructure beyond the physical meter, deployment of organizational capabilities such as advanced analytics and data governance/management, and alignment across multiple organizational stakeholders. Benefits realization in these categories will occur on independent timelines. Once the physical meter infrastructure is brought online, Toronto Hydro will undertake the specific IT projects required to set up system infrastructure to enable the use of AMI 2.0 insights for operations, asset management, and customer care.

2. Strategy for the upcoming rate period:

Approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life by 2025. Therefore, the utility intends to replace approximately 680,000 meters during the 2023-2028 period. As part of this replacement, the utility will introduce next generation smart meters and roll out the supporting network infrastructure.

3. Benefits:

The AMI 2.0 initiative brings about edge-computing network infrastructure and advanced capabilities to understand how electricity is generated and consumed in real-time. Some key advantages are listed below and summarized in Figure 11:

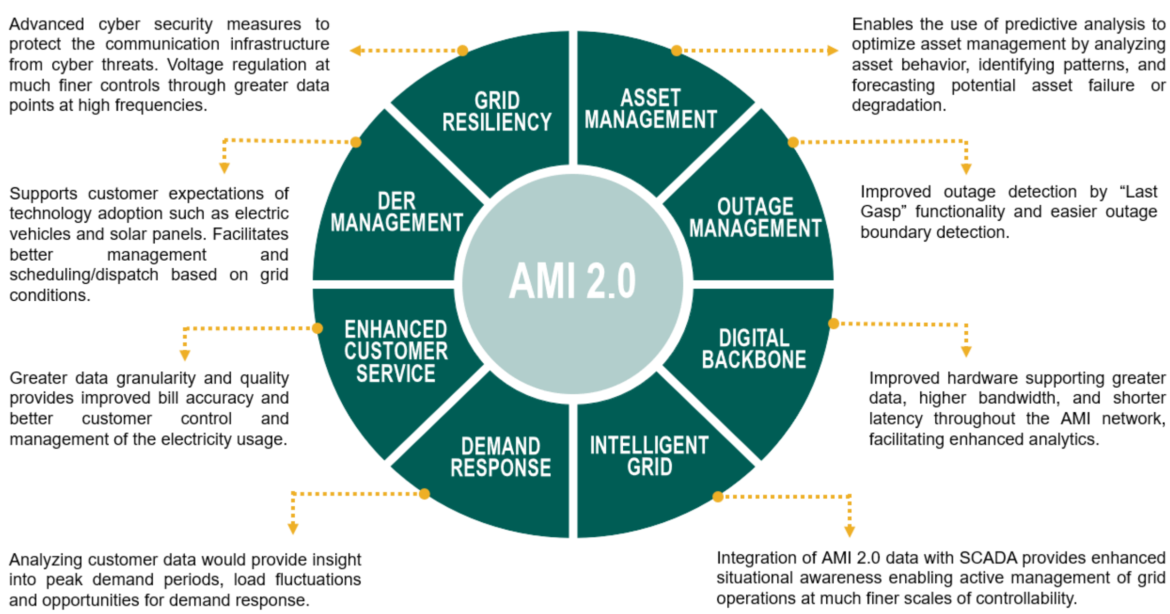


Figure 11: An Overview of AMI 2.0 Benefits

Improved visibility of the secondary network:

- Better investment planning can be realized by way of more granular data. The current FES model makes projections at the transformer station bus level, but with added visibility into the secondary network, the model could be expanded to the secondary transformer level.

This represents a step change in investment planning, as exhaustive geospatial projections provide planners better data for investment planning decisions.

- Better voltage regulation can be achieved by way of capturing voltage at many more points and at greater frequencies, allowing operators to regulate network voltage with much more control.
- Phase load balancing can be achieved by way of phase detection at endpoints of a circuit (the meter) – currently, crews are sent into the field to perform this measurement. Performing phase detection remotely, especially during storms, can reduce costs and improve grid reliability through real-time grid management.

Provision of last gasp functionality: AMI 2.0 meters enable automatic outage and restoration notifications ("last gasp") – currently, these notifications are required to be verified by phone or service call. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to more precise locations where they are needed, reducing costs and boosting the effectiveness of outage management operations. Meters also provide pinging capabilities, allowing the control room to monitor the status of outages and verify restoration quickly and accurately.

Improved understanding of customer-owned assets

- AMI 2.0 will provide insight into system voltages at the premise level, which is critical for determining when voltage violations from DERs and other assets are occurring and what actions may be necessary to mitigate such impacts. With more advanced DER monitoring and management, the utility could allow higher utilization factors for DERs as a result of greater confidence in DER management.
- Customers will be able to pair their meters with third-party software to provide a variety of services to control devices in their homes to manage their usage. This is particularly useful as a "plug'n'play" approach for future pilot projects that the utility may consider; with infrastructure already available, these pilots can be more feasible and cost-effective.

Scalability of infrastructure: AMI 2.0 can "future-proof" the meter as the ability to provide over-the-air updates will remove the risk of obsolescence of metering hardware over time. New capabilities of meters identified over time can also be rolled into new software and distributed over updates, providing flexibility to accommodate future technologies and customer expectations.

Enhanced data granularity and measurement

- The abundance of data provided by these meters will support development of analytical tools to expand on modernization capabilities such as predictive and prescriptive analytics, which will improve maintenance programs, asset management, and operational decision-making.
- Future integration with Energy Center will increase situational awareness and assist in curtailing/dispatching DERs for cases such as load management and reactive power management for voltage regulation.

4. Peer Success Stories:

For most utilities, the original business case for implementing AMI is generally focused around cost savings achieved from avoided truck rolls and the end of manual metering. Now that smart meters are becoming more commonplace in the industry, utilities are learning that the value of AMI goes beyond energy billing. These smart meters are representing a transformational shift in not only how utilities interact with their customers, but also how these meters serve as end-point sensors to obtain granular information about system operations and customer behaviour for data-driven decision making. Toronto Hydro has highlighted one of several peer success stories to give a sense of how utilities have achieved value from their AMI initiatives:

Peer Success Story	
Pacific Gas & Electric, California[15]	
Problem: PG&E relied on a limited number of research meters (~1,000) and SCADA data deployed at 60 percent of their substations to gather customer load information needed for distribution planning. The utility wanted a flexible way of aggregating load shapes for various configurations over different groupings of customers, which was not possible with their current method. Method: PG&E spent five years to develop the tools and processes (as well as transitioning to using AMI data as part of the utility planning process). Upon full transition, 4 million smart meters (representing 90	Selected Benefits: • Layered dashboard allowing operators and planners to visualize voltages from individual customer premise up to aggregated feeder level loads • Production of forecasts using hourly profiles for each circuit, customer class, and DER type • Improved peak planning from 24hours * 2days * 12 months = 576 data points to load shapes utilizing 8760 data points (number of hours in a year), representing a 15x increase in data • Development of 'Load Shape Viewer,' a tool that creates normalized load shapes with sensitivity

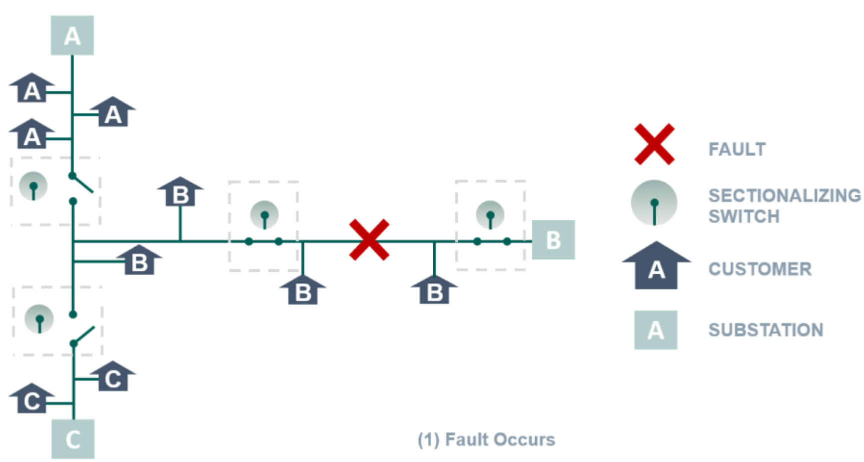
[15] U.S Department of Energy, Voices of Experience: Leveraging AMI Networks and Data, https://www.smartgrid.gov/files/documents/VOEAMI_2019.pdf

percent of their customers) were online with 99 percent accuracy, utilizing a 2-way 900 MHz RF mesh network.	from SCADA, weather, and temperature data input

D5.3.2 Appendix B – Fault Location, Isolation, & Service Restoration

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Fault Location, Isolation, and Service Restoration (FLISR) technology represents a transformative approach to power outage management; it enables quicker detection, precise isolation, and automated restoration of power in the event of faults or disruptions. FLISR leverages advanced sensors, a communication network, and intelligent devices (like SCADA switches and reclosers) already present on the grid to automatically determine the location of a fault. Once the fault is located, the software uses remotely operable devices to rapidly reconfigure the flow of power so that some or all of the customers on a feeder can avoid experiencing an outage. As this requires the ability to isolate portions of the network and re-route power from other sources, it is critical that the system is configured with sufficient sectionalizing SCADA switches and feeders that are tied by multiple paths to a single or multiple substation(s).[16]



[16] U.S Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf

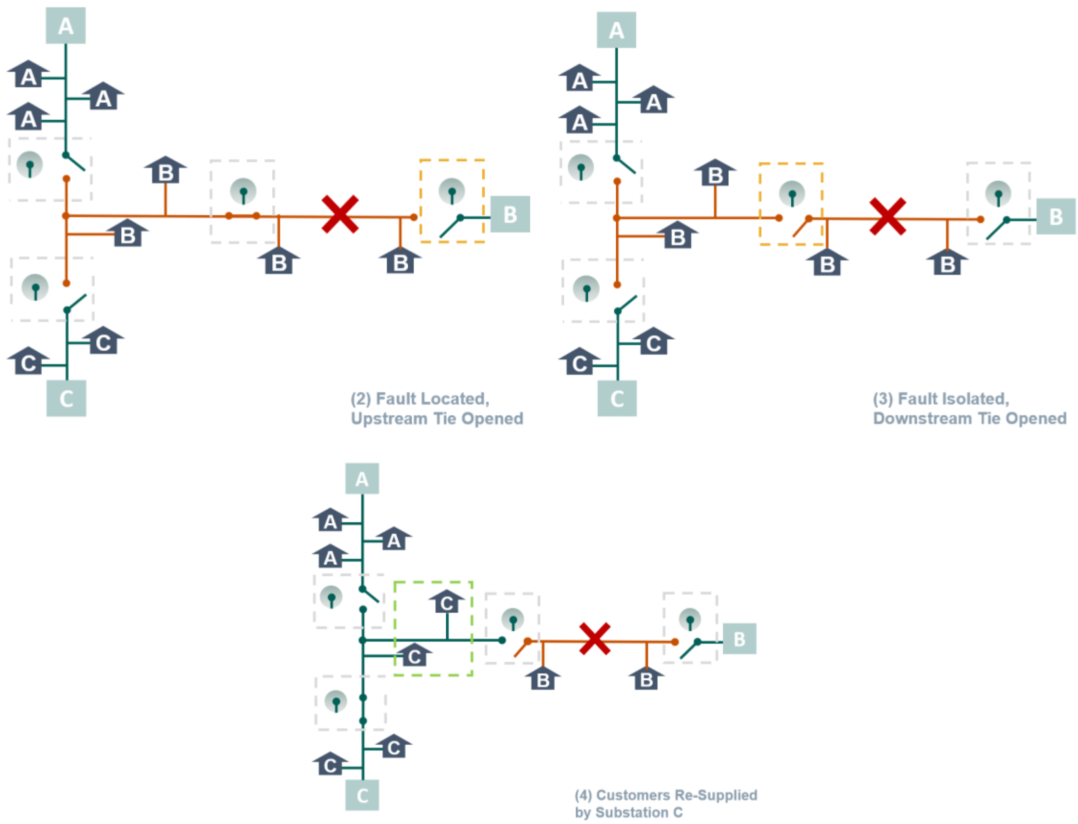


Figure 12: Schematic Overview of FLISR Operation in Four Stages

In Figure 12, (1) represents a fault scenario where the FLISR system locates the fault using sensors and reclosers that monitor flow of current. It then communicates the condition to other devices and/or the grid operators. Once the fault is located, FLISR opens the SCADA controlled switches from both sides of the fault, one immediately upstream closer to the source (2) and one downstream (3). At this stage the fault is isolated successfully. FLISR then closes the normally open SCADA controlled tie switch to reenergize the un-faulted part of the feeder (4). This process helps in minimizing the duration of outages which can be seen in Figure 13. In this illustrative scenario, FLISR automation is theoretically capable of reducing the restoration time from 45-75 minutes to 1-5 minutes.

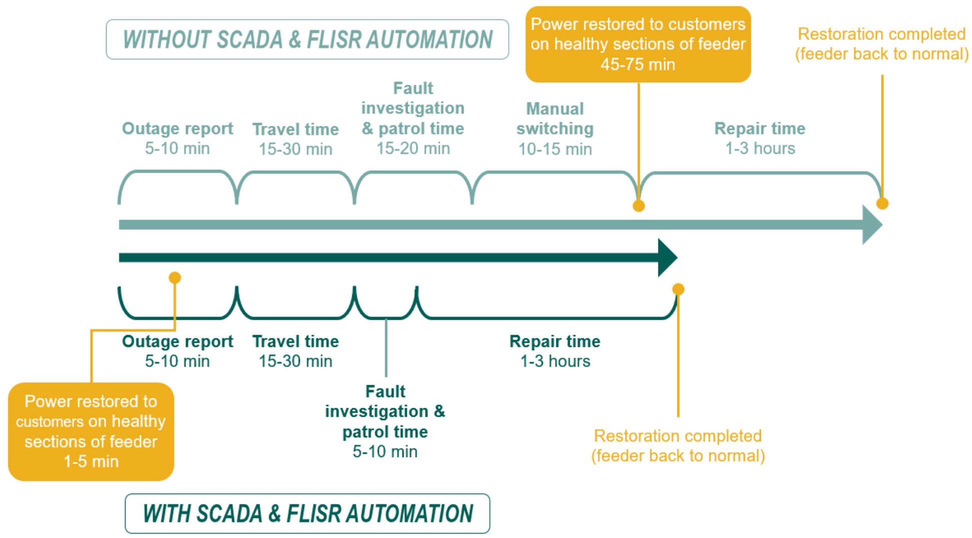


Figure 13: Typical timeline of Manual Restoration and FLISR

2. Toronto Hydro's Journey so far:

As FLISR utilizes information from a number of systems, it requires a substantive backbone of capabilities to successfully operate. Toronto Hydro is already set up with SCADA and Distribution Management System ("DMS") integration such that switches or feeders with faults are automatically displayed on the DMS. Fault status indicators were added to DMS in 2019, allowing controllers to more easily identify fault locations and determine which switches to operate in order to re-route power. And in 2020, voltage and current measurements were also added, as shown in Figure 14 below.

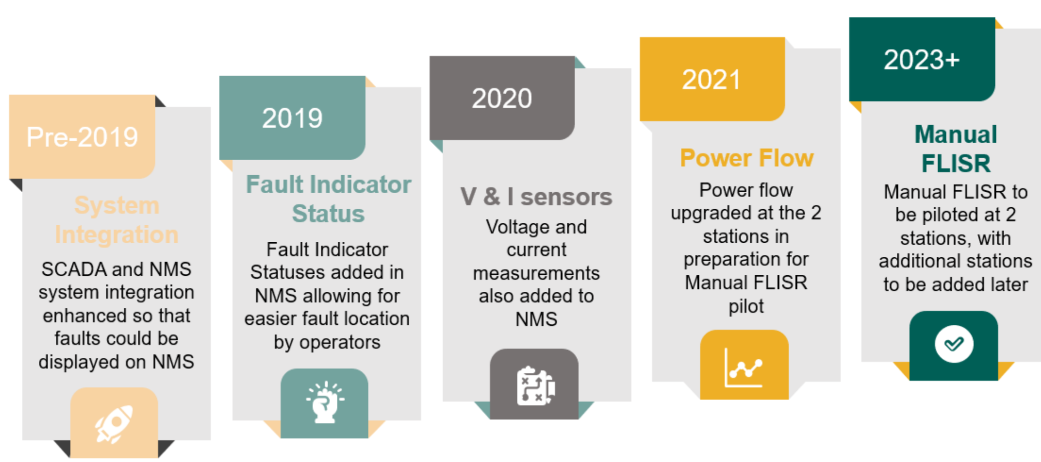


Figure 14: Timeline of FLISR Implementation

In 2021, a power flow upgrade was implemented which later enabled pilots at two stations (Finch and Bathurst) where manual FLISR started in 2023. The power flow upgrade is a data exercise that ensures accurate and high-quality data within Toronto Hydro's GIS and DMS systems. This data includes load from smart meters, conductor and other engineering attributes from CYME (Power Engineering Software), network topology and connectivity from GIS, as well as switch ratings. This integration will continue in the future as more monitoring and sensing devices are added to the system. Ultimately, having power flow is a more proactive way of operating the system versus switching blindly and risking reaching alarm limits. Power flow allows the utility to identify feeder capacities in real time, which in turn helps to identify the optimal switching procedure for the system. This is very powerful, especially in scenarios when feeders are close to overloading. It ensures operations do not have a negative impact on the system (i.e. moving load to a highly loaded feeder without this visibility). As more and more feeders reach their capacity due to growth on the system, this capability will become more important.

As part of its FLISR journey, Toronto Hydro is currently piloting manual FLISR at two stations (Finch and Bathurst), both of which are expected to be live prior to the 2025-2029 rate period. Manual operation is the first step in virtually every FLISR application as the fully automated FLISR solution typically requires extensive validation and calibration processes to ensure effective and reliable operations. This validation is done through manual validation of switching operations by control room operators. Operating the FLISR system manually and at a few stations at first will allow Toronto Hydro to evaluate the accuracy of the system's recommendations and assess how long it takes to come up with the solution. The learnings from the manual FLISR pilot will be used for change management when the system is fully rolled-out on the network. Prior to FLISR implementation, the "business-as-usual" procedure at Toronto Hydro consisted of the SCADA system notifying controllers of circuits that are experiencing faults. Controllers would then note down (on paper) which switches were seeing a fault. The circuits would then be identified in NMS and the procedure to restore power would then start. With manual FLISR, when an outage occurs, the system will determine its solution on how to sectionalize and restore power. The pilot will compare the "business as usual" procedure with the FLISR recommended procedure. This will help the project to continue to iterate until an optimal solution is reached.

3. Strategy for 2025-2029 rate period:

Over the next two years, Toronto Hydro will continue refining its data and network model. As this is carried out at pre-determined stations around the network, manual FLISR will be enabled. During the period between 2025 and 2028, manual FLISR will be tested at these target locations by the control room operators. The current criteria to move from manual to automatic FLISR at a station is for the manual system to see at least 20 faults of different types. Essentially, the safe transition from manual to automatic FLISR is contingent on a station seeing a certain number and diversity of outages, which is outside of the utility's control. However, as the utility begins piloting the system at the two initial stations, this requirement could change as more information about the operation of manual FLISR is gathered on Toronto Hydro's network. Additionally, planned ADMS upgrades during the 2025-2029 rate period are also necessary for auto FLISR enablement. Given these considerations Toronto Hydro's goal is that by 2030, stations in the Horseshoe area of the system should all be prepared for transition to fully-automatic FLISR.

4. Benefits:

Some of the major benefits of implementing FLISR technology are listed below:

- **Improved Reliability**: FLISR technology will enhance grid reliability by quickly detecting and isolating faults, minimizing the number of affected customers and reducing outage durations.
- **Improved Resilience**: With FLISR in place, the grid will become more resilient and adaptable to faults and disruptions. The ability to automatically detect, isolate and restore power enables the grid to self-heal and minimize the impact of incidents thereby improving overall grid resilience.
- **Minimized Customer Impact:** FLISR will minimize the duration of outage as well as the number of customers affected. This will result in reduced economic losses for customers and businesses.
- **Proactive Maintenance:** The FLISR technology and associated intelligent devices will provide valuable historic fault data which can be utilized to identify areas of concern and proactively addressing potential issues. By identifying fault patterns and identifying areas prone to recurring issues, informed decisions can be made about asset management.

D5.3.3 Appendix C – Enhanced DER Connection Process

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The DER interconnection process is centered around two core steps: (1) the customer or installer provides the technical specifications about the planned system; and (2) the utility evaluates the impacts to the grid and then either approves the application or communicates any necessary changes. However, obtaining the necessary information and keeping all parties up to date on the application status can be challenging— especially for utilities where the number of interconnection requests are growing.[17] As the adoption of DERs continues to accelerate across Toronto, it is likely that the city will see an increasing installed capacity base of DERs over the 2025-2029 rate period**Error! Reference source not found.**. In light of this, Toronto Hydro is committed to supporting t he energy transition by connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One and the IESO.

One of the primary challenges faced by Toronto Hydro due to the rising number of DER interconnections requests is the substantial amount of resources needed to evaluate and process applications. At present, Toronto Hydro's application processing methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants. This approach results in a resource-intensive and time-consuming procedure; with a rising volume of requests, the utility's current approach will challenge the ability to process applications within current lead time.

Increasingly, utilities across the world are using tools such as web portals to manage interconnection process and keep the customer informed about the end-to-end process. In its commitment to embrace an accessible, transparent, and customer-centric energy system, Toronto Hydro plans to develop a user-friendly customer portal to simplify the connection process and provide greater transparency for customers' DER integration journeys. This portal will enable customers to seamlessly review, submit, track (and if necessary cancel) their DER interconnection applications in a single, accessible source. On Toronto Hydro's end, there is potential to integrate semi-automated request handling and change orders, enabling seamless approvals and handovers between internal teams.

The shift towards a streamlined, digital connection process not only reduces administrative burden and manual data entry effort, but also fosters a more inclusive approach – one that reduces barriers to widespread DER adoption. The portal will also facilitate DER data collection in a centralized repository which in turn gives Toronto Hydro new analyses capabilities to identify DER trends,

[17] U.S Department of Energy, Voices of Experience (VOE), https://www.smartgrid.gov/voices_of_experience#:~:text=The%20Voices%20of%20Experience%20(VOE,and%20testing%20the%20emerging%20technology

impacts, and usage patterns for continuous grid operations improvement. The advanced functionality from a customer portal positions Toronto Hydro as a utility that is ready to embrace automation and handle the anticipated increase in DER connections. Through this initiative, Toronto Hydro is setting the stage for a more streamlined, data-driven, and efficient approach to DER integration – benefiting both the utility and its customers.

Peer Success Story	
PEPCO – Integrating Work Management[18]	
Problem: Noticed an increase in incoming calls and employees were spending more time helping customers understand the interconnection application process and finding missing information. Method: Embarked on a journey to develop an online portal in 2012 to allow customers to input their applications and help PEPCO manage workflow, data tracking, and regulatory reporting with a go-live in 2016. Portal development focused on splitting the application process into two steps and reorganizing staff around the steps: one team helps the customer and contractor with application journey from receival through approval to install; another team works with the customer journey from system build through authorization to operate.	Selected Benefits: • Intuitive and interactive application process guides customers step-by-step • Provides data validation, reducing application errors and missing information • Allows customers to monitor their application's status in near real-time through a personalized dashboard • New online contractor account includes the ability to designate access to multiple users • Quickly moves the application to the next step in the process • Ability to see aggregated reports for all pending applications submitted online by contractor • Online signature feature eliminates the need for physical signatures • Upload attachments online—no need to email or mail supporting documents

2. Benefits:

Toronto Hydro recognizes there is a wealth of opportunity in improving its current connections process methodology that relies heavily on manual processes through the use of emails and file sharing. Customers using Toronto Hydro's current system sometimes have concerns about DER applications and who to reach out to on the status and lead times for their applications. A streamlined, semi-automated customer connections portal can provide Toronto Hydro with the following benefits:

- Reduced delays and costs owing to reduction in manual data entry and labour hours in tracking and processing applications

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[18] *Supra* Note 17

- Consolidated and transparent communication channels providing timely application updates to customers
- Reduction in data entry errors and quicker customer notifications if further or corrected data is required

These enhancements will be necessary to ensure the utility can continue to provide high-quality customer service and meet connections application performance targets in the face of potentially higher rates of DER adoption over 2025-2029 and beyond.

D5.3.4 Appendix D – Hosting and Load Capacity Map

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Determining the DER capacity that the distribution system can accommodate is often a challenge, and without proper planning and integration, DERs and incremental loads may adversely impact system stability and hinder maximum benefits utilization. Toronto Hydro performs ad hoc studies and analysis to identify the feasibility of DER connection requests, which is a time-consuming process.

Hosting capacity analysis (HCA) has emerged as a valuable option preferred by several utilities across the world. It enables the assessment of available capacity for new DERs without the need for costly and time-consuming studies. In particular, it can illustrate the preliminary capacity of DERs that the power system can accommodate at a given point of interconnection without exacerbating grid parameters such as short circuit current. An effective HCA can assist Toronto Hydro in making informed decisions regarding strategic grid investments to reduce future barriers to DER integration. Additionally, it can boost efficiency and transparency of the DER planning and interconnection process to accommodate the increasing volume of DER connection requests.

This initiative complements the customer connections portal as the HCA can be used to generate a user-friendly hosting capacity map, such as the sample depicted in Figure 15 below, that provides preliminary geographical insights into the available interconnection capacity within Toronto Hydro's distribution system. The HCA map can be embedded or sit alongside the connections portal, enabling customers to guide the scope of their application prior to submission. The HCA map supports a customer-centric energy system, providing greater upfront visibility in potential application complexities and guiding customer investment strategy for future DER projects.

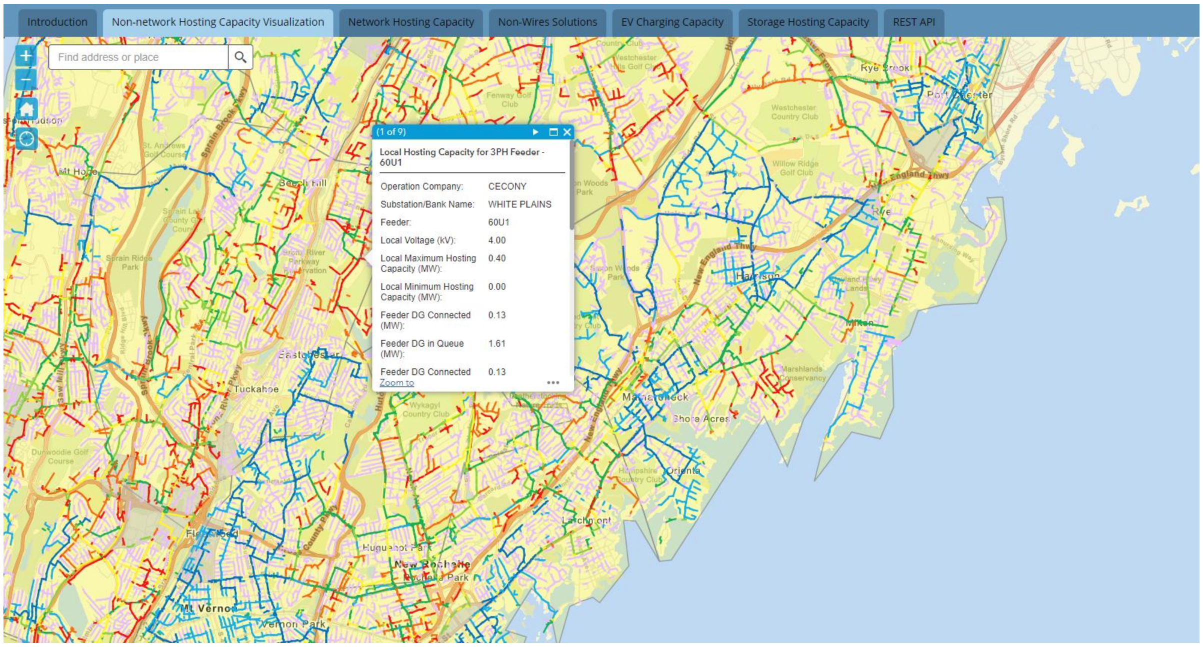

Figure 15: HCA Map Example – Consolidate Edison New York

Over the 2025-2029 rate period, Toronto Hydro intends to explore, develop and implement a Hosting Capacity Analysis and associated presentment tools. As part of this initiative, the utility will explore opportunities to calculate and present complimentary analyses, including load capacity constraints. Developing a hosting and load capacity analysis and presentment solution is a significant multi-year undertaking, as it will require upgrades to data quality and availability, the automated integration of various data systems, the development and implementation of complex, automated system analysis, and the procurement and implementation of a customer-facing geospatial visualization tool.

Peer Success Story

Hawaiian Electric Company (HECO) – Performing Daily Updates

Problem:

HECO originally looked at circuit penetration using the 15%-of peak rule, then transitioned to 50% of daytime minimum load and slowly rose up to 250% as more information and technologies became available to mitigate concerns; however, HECO determined that different feeder characteristics and infrastructure impact how much DER a circuit can handle.

Method:

HECO built a circuit model in “Synergi” (i.e. an asset simulation and optimization software) that feeds into their in-house hosting capacity tool. The tool runs an analysis of all primary circuits (from the substation to the transformer) and includes any PV systems (even if that system has not yet been installed). Location maps are created by running the analysis annually and ad-hoc. The tool provides an allowable amount of PV that can be easily interconnected for the entirety of the circuit.

Maps are updated daily based on new applications that are approved, which means that subsequent new installations looking to apply are evaluated against the capacity threshold for that circuit. If the installation size exceeds the hosting capacity limit, the application is sent for a supplemental review to specifically verify the location and how it would impact the circuit.

HECO separately reviews other conditions such as voltage rise/drop using a spreadsheet model to evaluate impact on the secondary network. This is especially important in sunny Hawaii where most DER installations are PV because the secondary side can experience voltage violations since most PV customers tend to generate maximum output at the same time (typically midday) rather than at various times throughout the day.

2. Benefits:

Some major benefits of implementing a Hosting Capacity Map for Toronto Hydro's service area are as follows:

- Increased visibility into the available capacity of the grid to host DERs to identify suitable locations for installations
- Integration with a future customer connections portal to update available capacity based on approved (but not yet installed) DER applications
- Increased visibility of system nodes with immediate or near-term capacity constraints to inform system upgrade planning to increase long-term hosting capacity
- Reduction in rule of thumb technical screens with introduction of granular analysis for the entire distribution system with regular updates

D5.3.5 Appendix F – GIS DER Asset Tracking

1. Introduction and Role in Toronto Hydro's Grid Modernization:

A forecasted increase in DER interconnections requests means that current data management practices that Toronto Hydro employs will no longer suffice without generating considerable administrative burdens and compromising data quality. Currently data from DER assets is manually entered, which is time consuming and prone to incomplete/incorrect data transfer. Toronto Hydro recognizes that automation will be a necessary core function at the heart of its data management methodology across difference processes associated with DER interconnection requests. While the customer connections portal initiative is a step towards automation by allowing DER asset data to be automatically recorded once an application is submitted and then approved, it lacks capability to visualize geographical and electrical connections to the distribution system.

Hence, a new tool that has emerged within the industry to bridge this gap is the concept of GIS DER Asset Tracking. The initiative explores the process and tools to streamline and standardize DER asset data in Toronto Hydro's GIS system. It aims to identify key asset information and connectivity data as well as integration requirements within GIS such that Toronto Hydro's record keeping procedure is streamlined and thorough. Apart from data quality and management, another key functionality of DER Asset Tracking which will be touched upon in the Monitoring & Forecasting activity is real-time monitoring and control of DERs. Currently DERMS is connected to Toronto Hydro's SCADA system to read real-time data; however, its System Map and DER one-line diagrams are not connected to GIS data in real-time – meaning that changes in physical location and configurations are updated on a monthly frequency requiring routine updates of the GIS extract file from GIS software onto the DERMS backend. As the number of DER assets continue to increase, a set frequency methodology will no longer fit Toronto Hydro's control toolbox in order to establish future extensions of programs related to demand response, market prices, voltage fluctuations and more.

As Toronto Hydro embarks on its mission to become a utility of the future, integration of DER asset information in GIS systems for monitoring and control purposes will be crucial to encourage and accommodate new DER connections. GIS DER Asset Tracking rounds off the other two *Facilitating DER Connection* initiatives as it links together the seamless flow of data from end-to-end of the connections journey and provides the right kind of data required to refresh a hosting capacity analysis with the least amount of manual intervention needed. The three initiatives work together to give confidence that Toronto Hydro understands on a granular level where current DER assets sit on the system and where future ones can be anticipated and accommodated in a timely manner.

2. Benefits:

Toronto Hydro recognizes that streamlining the data management process associated with DER connections requests comes with a wealth of benefits. Some major benefits of implementing GIS DER Asset Tracking is as follows:

- Robust organization of DER interconnection data from application submission through to installation and commissioning through industry-leading data management practices

- Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms
- Increased efficiency of data transfer through integration of data from systems such as the proposed customer connections portal, GIS, and Energy Centre without the need for manual effort in syncing data across platforms

D5.3.6 Appendix G – Energy Center Enhancements

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Distributed Energy Resource Management System (DERMS) is a powerful software tool which can be used to integrate, aggregate, monitor and control DERs located in front or behind the meter in real-time. As deployment of these assets such as solar panel and battery energy storage systems continues to expand, utilities face the challenge of preparing for a well-coordinated integration of DERs on grids that were historically designed for predictable, one-way energy flows.

From an operational perspective, this includes proper management, control, and operational oversight given the variability in DER output to prevent issues such as high voltages during peak hours, abnormally low voltage during load recovery periods, and intermittent voltage fluctuations. From an ownership and operation perspective, the delineation of who owns and manages DER assets also lends uncertainty in how to achieve optimal grid management; key considerations include the majority of DER growth comes from assets not owned by the utility, immature technology can complicate interoperability, the number and distribution of DER endpoints can challenge the scalability of utility-driven solutions, and dispatch of DER assets may not necessarily align with stakeholder values (e.g. a third-party owned DER may be dispatched to reduce an electric bill which may not be aligned with the utility operator at that point in time).

The introduction of a DERMS serves as a vital step in consolidating the visibility of DERs across the grid, and it lays the groundwork for exploring third-party involvement and partnerships in DER and DERMS ownership and control as the complexity of ownership models and interoperability increases in a maturing technology space.

Most DERM systems have the capability to exchange data and control with other enterprise supervisory control systems such as control systems with the ADMS platform. DERMS also serves as the system of record for all DER related data, and provides operators visibility to the parts of the grid not visible to the ADMS. DERMS comprise of the following core functions:

- **Aggregate**: DERMS take the services of multiple DERs and present it as an aggregated smaller group of more manageable virtual resources that are aligned with grid configuration.
- **Translate**: DERMS can extract a variety of data from different DERs that may use various communication protocols and present it to the upstream controller in a streamlined view.

- **Simplify**: DERMS has the capability to provide simplified services that are useful to distribution operations, which are power-system centric as opposed to DER centric.
- **Optimize**: DERMS can provide requested services by coordinating functions depending on location and circumstance.

Toronto Hydro incorporated DERMS in 2019 in the form of its Energy Center. Phase 1 of system implementation focused on real time monitoring of DERs; in its current state, the Energy Center provides visibility to approximately 2,200 DERs connected to the system, including three utility-owned battery energy storage systems. Currently DER control capabilities are unavailable, although utility-owned DER sites can be controlled via SCADA on vendor specific platforms. With almost four years of experience in operating the Energy Center, there is now a need to explore expansions to it.

2. Current Energy Center Modules – Monitoring and Forecasting:

Energy Center facilitates real time monitoring of DERs through visualization of the complete portfolio of DERs to provide up-to-date information on the status, performance, and health of DER assets. This data is used to assist in promptly identifying any operational issues or deviations from expected performance. The data can also be parsed by DER type, as well as a hierarchical outlook across the system, regions, terminal stations, and municipal stations, which is particularly useful to gain perspective of DER distributions across the system by type to assist with grid planning. Individual DER monitoring, as shown in Figure 16, expands on details such as one-line diagrams, alarms, generation/consumption, and charging/discharging, which is useful for operators to identify potential issues such as voltage fluctuation and SOC battery issues. Overall, a consolidated view of DER asset performance makes it easier and quicker for decision-making.

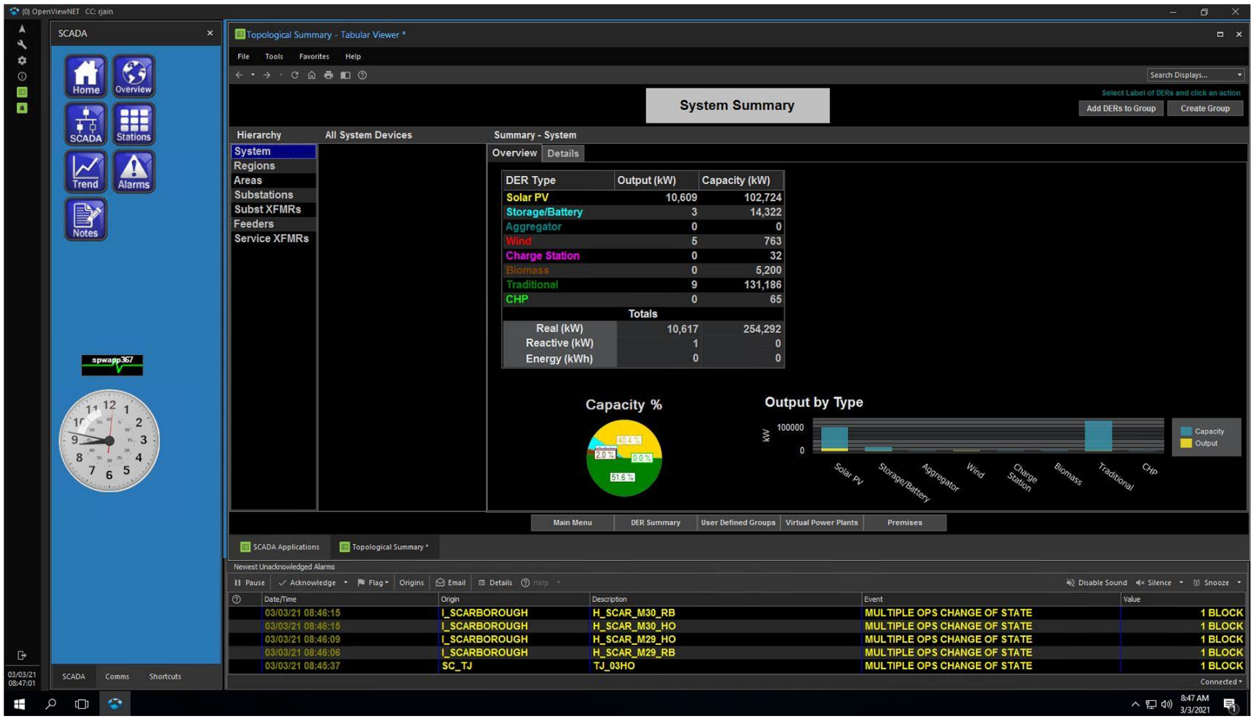

Figure 16: Energy Center Overview Screen

The second function currently available in Energy Center is a forecasting tool that enables Toronto Hydro to create accurate load and renewable generation forecasts for periods ranging from 1 – 35 days. These forecasts use the historical archive of area load, renewable generation and weather data, and a variety of user-selected algorithms/models to generate load demand and renewable generation outlooks for the selected period. These forecasts enable the utility to anticipate fluctuation in generation and consumption patterns of DERs and accordingly plan for contingency actions. In current operations, Toronto Hydro uses load forecasting at two stations to carry out LDR programs by way of battery dispatch scheduling to achieve peak shaving.

3. Building on Monitoring and Forecasting:

As Toronto Hydro continues to evaluate and connect more DER assets, generating insights and value derivation from these assets becomes limited without access to quality, structured data. While the current implementation of the Energy Center allows the utility to see direct information about their DER assets on one platform, understanding how DER operation and coordination will affect the grid down to the feeder level is not yet possible due to lack of visibility. Similarly, asset data related to DERs are not yet streamlined and are updated manually on a set frequency, which means that synchronizing data into the Energy Center for new assets occurs in a piecemeal approach with room for data error.

This is where the integration of technologies mentioned throughout the Grid Modernization strategy will play a role in augmenting the monitoring and forecasting capabilities of the Energy Center. System observability enhancements such as AMI 2.0 and sensor installations will provide more granular customer consumption data and patterns as well as visibility into feeder loading conditions and power flows. This coupled with the roll-out of FLISR enables automated fault management, removing the human element of complex decision-making in real-time. In such an environment, the Energy Center can now play a new role – if the grid is now able to more intelligently identify and minimize feeders off-supply, data integration and communication with the Energy Center now means that utility-managed DER assets are able to play a role in restoring or stabilizing other parts of the grid through fault and post fault events. Greater visibility of the grid at the low-voltage level also opens up the ability to run more granular forecasts in the Energy Center to develop operational plans. This can be used at multiple stations beyond the two currently used for LDR and provide data to support targeted expansion of the program. Furthermore, forecasting scenarios that factor in geospatial distribution of DER assets and their implications on the capacity of the system at target points on the network will become an essential tool in the utility's investment planning process, deferring or avoiding capital expenditure where it makes sense. Finally, the implementation of GIS DER Asset Tracking ensures that the organization has confidence in data available in the Energy Center and has the added ability of running forecasts ahead of time for asset applications that have been accepted but not yet connected to understand implications, if any, before the DER is switched on.

4. Future Modules - Scheduling and Dispatch Module:

Currently, Toronto Hydro is unable to efficiently schedule, aggregate, and optimize a set of utility-owned DER assets. Instead, existing DER assets are manually operated and/or managed through vendor-specific platforms. Specifically, the control and management of utility-owned DERs is complicated due to the increased training, management, and licensing requirements for multiple platforms and the lack of control of all sites from a single, centralized location. There is a clear commitment from Toronto Hydro to increase energy storage capacity through the Non-Wires Solutions program; successful implementation necessitates a centralized dispatching and scheduling platform.

Therefore, Phase 2 involves the implementation of an **Advanced Scheduling and Dispatch** module in the Energy Center which features a consolidated platform for real-time control and management, as well as establishing interoperability between storage management systems and Energy Center. Having a system that provides control capabilities allows the utility to better collaborate on upcoming pilot projects using innovative technologies (e.g. IESO's Grid Innovation Fund), improve use case development for demand response, and simulate and understand risks associated with maturing technologies.

The DER Advanced Scheduling & Dispatch module allows scheduling for objectives such as peak shaving, back feed avoidance, and load flattening. It can create schedules for any level of electrical network hierarchy using any type of controllable DER, including batteries, curtailable wind and solar generators, demand response programs, and backup diesel generators. The time intervals of the schedules can be as little as 5 minutes or as much as 1 hour, and the schedules can be for up to 35 days into the future. As part of implementation into the Energy Centre, the module will support two key functions: (i) Peak Shaving and Control (Dispatch) of DERs; and (ii) Automation of Demand Response. The module is expected to go-live in 2024 following a launch and test of the module on development, quality assurance, and production environment of Energy Center, as well as successful test of schedule and dispatch functionality of at least three utility owned BESS assets.

The module is expected to provide some of the following benefits:

- Enhanced Integration of DERs: optimize and coordinate charging and discharging of utility-managed BESS assets to balance capacity and demand in feeders with current or expected REG assets, which are non-dispatchable;
- Efficient management on a consolidated platform: eliminate reliance on various vendor-managed platforms, eliminating or reduction costs associated with training, maintenance, and licensing as well as quicker and efficient IT upgrades onto one system, reducing downtime; and
- Participate in projects and expanded flexibility service programs: enable Toronto Hydro to participate in upcoming pilot projects related to DERs by facilitating a "plug-and-play" solution for new technologies to be tested, and facilitate studies to quantify value in expansion or new offerings in flexibility services at constrained or soon-to-be constrained areas of the grid.

D5.3.7 Appendix H – Low-Voltage Level Forecasting

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The Future Energy Scenarios (FES) provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto, as well as an assessment of their potential impacts on Toronto Hydro's electricity distribution network. FES was contracted through Element Energy, an UK-based energy consulting firm, that has provided similar load forecasting models to various distribution network operators and the electricity system operator in the UK. While the first iteration of FES focused on forecasting load at the bus level, Toronto Hydro is aiming to explore the extension of this modeling exercise to the low voltage network; for example, on the feeder or secondary transformer level. The full FES report can be found in Exhibit 2B Section D Appendix E.

FES is predicated upon a highly granular consumer choice-based analysis of future loading conditions at the desired modelling level (i.e. bus-level, feeder-level), providing a strong evidence base for network planning and the evaluation of future infrastructure investments. To capture the range of uncertainties in a coherent and meaningful way, multiple scenarios are developed (represented as "scenario worlds"), consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, and illustrate the best view of future energy system changes for a given set of economic, social, and policy assumptions.

The projections are created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. These projections create uptake scenarios for each of the drivers of demand and generation considered in the FES model. These drivers include, for example, electric vehicles, energy efficiency measures and solar photovoltaic installations.

2. Benefits:

FES establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements. FES results give planners insight into the potential geospatial distribution of electrification on the network and allow for detailed analysis into the make-up of that electrification; be it EVs, DERs, or heat-pumps.

The increased granularity that feeder or secondary transformer level modelling provides would give planners even greater levels of detail about the system and further narrow down areas of the network which require investment. For example, feeder or secondary transformer data could be used to confirm the real-time data that is collected as part of the system observability program.

D5.3.8 Appendix I – Innovation Pilot Projects

1. Flexible Connections Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The rapid integration of Distributed Energy Resources (DERs) assets into the distribution network poses several technical constraints if not proactively managed and coordinated. These include reverse power flow (particularly in low load scenarios), compromised power quality, voltage violations, and elevated fault levels. Consequently, DER customers looking to connect to the network may be faced with financial and time-related burdens associated with network upgrades due to technical and standards constraints. In order to improve customers' ability to access available capacity at an affordable connection cost, alternative solutions could be explored, capitalizing on innovative technological and commercial offerings.

The Flexible Connections Pilot seeks to develop and implement a comprehensive framework that facilitates the efficient and cost-effective integration of DG assets into constrained areas of the distribution network. This would be achieved through development of an advanced DERMS system coupled with intelligent device installation utilized through a communications platform. "Flexible" refers to the network's real-time adaptability in managing network constraints and DG access to network capacity without the need for network upgrades.

b. Description of Pilot:

Flexible DG connections allow DER assets to connect to the network on a constrained basis whereby their operation can be controlled by the network operator within network operational limits. To enable this offering, Toronto Hydro would need to develop both the technical and commercial systems as part of a holistic approach. Firstly, seamless operation of DER assets will require Energy Centre to have the ability to not only monitor, but also control DERs. Real-time awareness of system characteristics will require sensors and smart devices installed on the network – this is currently being achieved as part of Toronto Hydro's Intelligent Grid strategy. The coordination of these devices and the management system will require a robust telecommunications platform to facilitate the necessary information exchange and control capabilities. Finally, extensive customer engagement and the development of novel commercial agreements between the utility and participating DER customers will enable practical implementation. The streamlined approach is geared towards enabling faster, cheaper DER connections while avoiding the need for Toronto Hydro to embark on similarly expensive and time-consuming network infrastructure upgrades.

c. ***Benefits:***

A Flexible Connections pilot allows Toronto Hydro to identify and mitigate any unintended consequences of flexible connections before providing it as a standard offering. Additionally, Toronto Hydro can better understand and manage local DER customer concerns to ensure proposed commercial arrangements are attractive offerings, therefore enabling sufficient trial participation. If implemented, Toronto Hydro would benefit from cost-efficient reinforcement decisions and enabling DER connections with lower electrical losses by locating generation closer to demand. DER customers connecting to the network would benefit from reduced time delays and cost upgrades. Customers could also benefit from earlier participation in future Flexibility Service offerings and increased dynamic control of DG outputs without compromising network safety.

2. EV Commercial Fleets Pilot

a. ***Introduction and Role in Toronto Hydro's Grid Modernization:***

In 2020, fleet energy consumption accounted for 33 percent of CO_2 emissions in the City of Toronto. The successful electrification of commercial fleets is needed to achieve the city's net-zero target by 2040. Specific objectives include having 30 percent of registered vehicles in Toronto be electric and ensuring that 50 percent of the TTC bus fleet is zero-emissions by 2030.

As the demand for system flexibility increases and battery technology costs decrease, the electrification of transportation becomes increasingly important in accelerating the transition to net-zero emissions. However, widespread adoption of commercial fleet electrification may trigger considerable costs to upgrade the distribution system, and may result in significant connection costs due to the higher payloads of commercial vehicles and dissimilarity in load profiles when compared to domestic charging. Therefore, it is essential to investigate and identify the impact of commercial EV fleet charging on the distribution network and develop technical and commercial strategies to facilitate their integration while reducing associated costs for customers.

The unmanaged electrification and charging of fleets could pose a substantial load impact on the distribution system. This project aims to collaborate with fleet owners to assess the impact of commercial EV fleets on the grid, both in terms of quantifying and minimizing load impact. Additionally, the project will explore opportunities to coordinate commercial fleets as a flexible load within the distribution system for both at-home and depot charging scenarios.

b. Description of Pilot:

The Commercial EV Pilot will examine the impact of commercial EV fleet charging at homes and at depots, and optimize charging schemes based on the flexibility requirements/preferences of Toronto Hydro and agreed upon by project partners. These tasks will offer insights into managing charging schemes for the most common charging locations, identifying methods for easy and cost-effective fleet electrification, and optimizing commercial fleet charging while considering flexibility services. Moreover, the project will assess the usefulness and benefits of flexibility services to Toronto Hydro. Additionally, demand forecasting and mitigation planning can be achieved once data is aggregated from the above studies.

The project's scope entails collaboration with major commercial fleet operators to assess the impact of their fleet's electrification on the distribution system. Various testing methods are employed to gain insight into diverse charging options and develop an effective implementation strategy for fleet operators. The project encompasses quantifying and minimizing the network impact of commercial EVs through trialing different methods, exploring the total cost of ownership of smart solutions for EV fleets operators, and determining the necessary infrastructure to facilitate the EV transition. Technical solutions are tested and implemented by fleet operators and Toronto Hydro, including flexibility services to grid from commercial EV fleets on domestic connections and planning tools for depot energy modeling and optimization with profiled network connections.

c. Benefits:

The project would develop the ability to quantify and minimize the impact of commercial fleet electrification on the distribution network, investigate and quantify the total cost of ownership for intelligent scheduling and charging solutions for EV fleets, and identify the necessary infrastructure, including network, charging, and IT components, to facilitate the transition to EV fleets and enable effective load management.

3. Electric Vehicle Demand Response Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The adoption of electric vehicles (EVs) in Toronto is expected to accelerate due to a range of policies, incentives, and grants from all three governments, some of which include: the new Ultra-Low Overnight Electricity Price plan released by the Ontario Energy Board (OEB), a federal proposal for a Zero-Emission Vehicle Mandate (25 percent of all passenger vehicles sales must be electric by 2026, jumping to 60 percent by 2035), and Ontario investment in the construction of two new EV battery plants in St. Thomas. Additionally, Toronto Hydro's own Future Energy Scenarios load forecasting tool (FES) sees 300k BEV cars on Toronto roads by 2030 and 1.8M by 2050 in a Consumer Transformation scenario. This transformative shift poses several network challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously. Conversely, beyond low carbon transport, EVs can be leveraged as a DER thanks to the ability to charge and discharge from its battery. In order to maintain system stability and enable EV uptake in Toronto, it is crucial to explore EV demand response strategies in the forefront of change.

The EV Demand Response pilot aims to identify viable technical hardware and control models along with demand response (DR) events to facilitate coordinated charging and potential discharging of EV batteries to support network needs. This would be achieved through development of applications, hardware integration, and mechanisms to identify and trigger EV DR events to support trials and roll-out with Toronto-based market participants.

b. Description of Pilot:

EV demand response programs would allow Toronto Hydro to manage EV charging in real-time based on grid conditions, appropriate to the type of conditions occurring on the network. Currently, phase 1 of an EV Smart Charing pilot is being trialled with Elocity. This explored testing new hardware to convert simple chargers to "smart" by adding a device to connect to the internet and turn on-off as well as inclusion of a customer application and utility portal to trigger DR events. In a subsequent phase, Toronto Hydro intends to explore:

1. A review of available technologies for smart charging;
2. Test technical control options such as the Open Charge Point Protocol (OCPP) with electric vehicle supply equipment (EVSE), leverage other EVSE providers to trigger DR events, and onboard a vehicle telematics control to directly connect with vehicle original equipment manufacturer's (OEM) applications; and
3. Broader corporate tool integration into Energy Center and other metering systems to further real-time situational awareness to deploy EV DR assets to address specific network needs

The pilot would benefit from stakeholder engagement with customers, automakers, EV charge-point manufacturers and operators, industry bodies, and academia to inform and shape a full-scale EV DR program. By developing a strategy that builds on industry-wide learnings, the pilot aims to facilitate the uptake of EVs while helping Toronto Hydro reduce peak demand and defer network upgrades.

c. __Benefits:__

Toronto Hydro is uniquely positioned to evaluate and test relevant mechanisms in the largest city in Canada, where significant EV uptake is expected to occur in the next 10-30 years, and where its urban environment limits the amount of off-street charger installations. If implemented, the pilot is expected to leverage current initiatives and inform future approaches to other Non-Wire Solution programs such as:

- Local Demand Response program – measured meter data from individual chargers can be compared to aggregated transformer meters to verify the impact on the secondary distribution grid
- Hosting Capacity Map – identification of potential capacity constrained areas, providing visibility for medium to long term planning
- Intelligent Grid portfolio – sensors and automation tools being installed under this portfolio can provide real-time visibility and signals for EV demand response trials.

If EV Demand Response is rolled out as a business as usual offering, it could represent a flexible and intelligent solution to managing EV load and maintaining grid stability; one where benefit stacking could be applied in the future as consumer behaviours and markets evolve. Furthermore, EV customers could benefit from increased participation with the utility to better manage electricity use through a wider range of choices on charging times, types, and incentives.

4. Advanced Microgrid Pilot

a. __Introduction and Role in Toronto Hydro’s Grid Modernization:__

The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages. This is a particular concern for population segments and services that rely on power for mission-critical needs. An intelligent, whole systems approach is required to create a resilient energy system, ensuring a secure balance between energy supply and demand despite internal/external factors.

The Advanced Microgrid pilot seeks to build upon a white paper completed by Quanta Technologies and perform a desktop study on viable microgrid topologies within Toronto Hydro's network followed by a field demonstration if applicable.

b. Description of Pilot:

Microgrids are electric energy systems that can function while either connected to a main distribution grid or disconnected from it. While disconnected, it is composed of DERs, storage units, and energy loads, and typically uses the same technologies and techniques as a larger utility grid. Microgrids can connect and disconnect from the distribution grid, allowing for the exchange of energy and the supply of ancillary services, and the systems can either be located behind-the-meter (BTM) or front-of-the-meter (FTM).

Currently, the main barrier to widespread implementation of microgrids is financial viability. There continues to be uncertainty and limitations for the various business models proposed for these systems, including revenue structures and pricing schemes. While single-customer microgrids have been tested at research institutes in Toronto and within utilities in the US, there has not yet been a demonstration of multiple-customer or utility microgrids in Toronto as literature review has found that most use cases for microgrids are met in part by existing commercially available technology. These include, but are not limited to, capacity deferrals, improving power quality, providing black start capability, and avoiding DER curtailment. However, gathering data to support microgrid viability in the context of a urban setting requires a demonstration specifically in Toronto Hydro and Ontario's energy system structure in collaboration with project partners such as key accounts, vulnerable customers, and customers with critical loads.

Overall, it is expected the trial will provide clarity on the commercial viability of one or more microgrid models. Key factors include the preferred level of system complexity, level of utility control, public-private investment vs ownership, and evidence supporting regulatory review and reform if required. These factors will help shape the scope and breadth of future microgrid projects that Toronto Hydro would like to see connected to the grid, whether initiated by the utility or its customers. The pilot can also leverage the future DERMS/Energy Centre for dispatch and monitoring of DERs within the microgrid boundary.

c. Benefits:

An advanced grid pilot allows Toronto Hydro to test viable microgrid topologies within the Toronto Hydro network and Ontario energy system structure to determine the commercial viability of grid resiliency and grid services. Additionally, through the course of the pilot, Toronto Hydro would benefit from understanding and managing overall customer and third-party concerns about power safety, quality, and security, which can be used to augment core operations and other NWS programs. If microgrids are provided as a standard offering, either FTM or BTM, Toronto Hydro would benefit from a flexible resource to sustain operations during outages, provide ancillary services to the wider grid, and enable new methods to connect renewable resources. Customers within microgrid boundaries would benefit from a significant reduction in interruptions and outage times as well as participating in new service offerings if applicable.

D6 Facilities Asset Management Strategy

Toronto Hydro manages a broad portfolio of facilities comprised of 185 stations, two control centres, two data centres, and four work centres. These assets house and protect grid equipment, and create the necessary conditions to enable employees to work effectively and efficiently. Investments in the renewal, maintenance, enhancement, and expansion of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner.

The primary objectives of the Facilities Asset Management Strategy (the "Strategy") are to maintain the safety, reliability, and functionality of stations and work centres. Meeting these objectives requires the utility to regularly inspect and sustain its facilities assets and the critical building systems in good working order. In addition to these table stakes, the Strategy addresses emerging needs and priorities to expand the distribution grid to serve growing customer demand, enhance facilities assets to decarbonize Toronto Hydro's emissions, and provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather.

The Strategy governs Toronto Hydro's facilities Investment Planning and Forecasting ("IPF") process through the following streams, which are described in more detail below.

1. Asset Management Process
2. Facilities Enhancements Initiatives
3. Long-term Planning Considerations

The scope of investments covered by the Strategy includes the following types of facilities assets and building systems:

- Structural and envelope assets such as walls, façades, beams, and columns;
- Architectural and interior assets such as roofs, doors, finishes, and ceilings;
- Fire and life safety assets and systems such as fire alarms, sprinklers, signage, and emergency lighting;
- Mechanical, electrical, and plumbing assets and systems such as HVAC, lighting, plumbing fixtures, sump pumps, and hot water tanks; and
- Civil and sitework assets such as walkways, driveways, parking spaces, gates, and barriers.

D6.1 Asset Management Process

Toronto Hydro facilities asset management process is aligned and integrated with the utility's overall Asset Management strategy detailed in Exhibit 2B, Section D1.

The condition and lifecycle stage of an asset are the primary considerations in the development of the facilities asset investment plan. Generally, the utility replaces facilities assets that are identified to be in poor condition and past useful life. After an asset is identified as having these characteristics, the utility implements a plan to upgrade or replace the asset to restore and enhance its functionality in accordance with current standards and objectives.

Toronto Hydro considers the following types of inputs in the asset lifecycle management process:

- Building Conditions Assessment ("BCA");
- Asset Registry data maintained through Toronto Hydro's Computerized Maintenance Management Software ("CMMS");
- Industry standard useful life data (i.e. ASHRAE and RS Means Data);
- Assessments and reports by experts (e.g. Asbestos Containing Materials Report, Designated Substances Report, Water Infiltration Report, Roof Condition Assessment, lighting assessment reports, Current Condition and Code Compliance of Vertical Service Ladders, and Security Systems Assessment);
- Lessons learned from past projects; and
- Business impact to Toronto Hydro.

The Building Condition Assessment ("BCA") is central to evaluation and prioritization of asset renewal investments which feed into the utility's overall planning process described in Exhibit 2B, Section D1.

To enable the BCA, the utility collects and analyzes information about the condition of its facilities assets on an ongoing basis, as follows:

- **Daily:** Asset condition observations are captured on a daily basis through the Preventive Maintenance Program ("PMP") and the CMMS system.
- **Monthly:** Toronto Hydro conducts monthly field inspections and safety audits to review asset condition observations captured in the CMMS and perform preventive checks.

- **Annually:** The utility annually reviews asset condition observations captured in the CMMS through the daily and monthly processes, as well as lessons learned from that year's projects, to verify and revise the BCA score for each building as required; and
- **Biennial:** Toronto Hydro resets the BCA cycle and fully re-evaluates buildings biennially.

The BCA follows the Uniformat II categorization, which assigns each building asset and system three scores for each of the following parameters:

Table 1: Building Condition Assessment Uniformat II Categories

Rating	Current Condition	Probability of Failure	Impact of Failure
1	Critical – not serviceable or irreparable	System Failure – Immediate Attention	Critical System
2	Poor – not functioning as intended	Imminent Breakdown - Critical (1-2 Years)	Building Functionality
3	Fair – functioning with noticeable wear/use	Imminent Breakdown – Non-Critical (Rate Plan)	Run-to-Fail
4	Good – functioning with minor wear/use	Improbable Breakdown – (5-10 Years)	Redundancy of Cost-Effective Upgrade
5	Excellent – in new or near-new condition	Highly Improbable – (10+ Years)	Elective Upgrade

The scores are then combined in a weighted formula, along with site priority factors based on building usage, to provide a single ranking known as the Risk Priority Number ("RPN"). The RPN supports Toronto Hydro's decision-making by pinpointing the most critical needs by building system and provides a ranked, quantified evaluation of assets.

D6.1.1 Lifecycle Analysis

Lifecycle economic analysis is an important aspect of cost-effective lifecycle asset management. The objective of this analysis is to minimize the asset's total lifecycle cost while ensuring safe and reliable asset performance. Toronto Hydro achieves this objective by tracking the end of economic life, which is the point where total cost of the asset (including ownership and maintenance costs) is at its lowest over the asset's lifecycle. Along with the BCA and other inputs discussed herein, the lifecycle analysis enables Toronto Hydro to make well-informed asset renewal investment decisions.

D6.1.2 Legislative and Technical Standards

Toronto Hydro's facilities standards are based on legislative requirements and technical, professional, or regulatory standards. The former include the Ontario Building Code, the Ontario Fire Code, and *Accessibility for Ontarians with Disabilities Act, 2005*.

Technical standards vary from project to project and may include: ASHRAE (American Society of Heating, Refrigerating and Air-Conditioning Engineers); ESA (Electrical Safety Authority); TSSA (Technical Standards and Safety Authority); CSA (Canadian Standards Association); EUSR (Electrical Utility Safety Rules); and in the future, ISO55001 (International Organization for Standardization – Asset Management).

D6.2 Facilities Enhancements Initiatives

In prioritizing facilities asset investments, the top drivers are safety (including compliance with legislative requirements), reliability of electrical distribution equipment, and functional availability to ensure business continuity. Once investments have been triggered by one or more of these drivers, Toronto Hydro evaluates whether there is opportunity for the asset's repair or replacement plan to have increased enhancement to achieve additional goals, including greater resilience against natural and physical threats such as extreme weather and vandalism, or deliver reductions in greenhouse gas emissions, including advancing energy efficiency outcomes.

Weather Resilience and Physical Security Enhancements: The natural, physical, social, and geopolitical circumstances affecting Toronto Hydro's distribution system also affect the utility's facilities and drive a key part of facilities enhancements. As discussed in Exhibit 2B, Section D5, the effects of climate change such as rising average annual temperatures, average annual precipitation, and extreme temperature and precipitation patterns require Toronto Hydro to prepare its infrastructure—including its facilities supporting the core distribution infrastructure—to withstand and adapt to these conditions. Separately, but equally importantly, hardening stations and work centres to prevent and mitigate physical security risks such as unauthorized access, vandalism, theft, trespassing, workplace violence, or terrorism is essential to ensuring the security and safety of the utility's personnel and the general public, and the reliability of the distribution system, especially in the face of pervasive cyber security threats emerging against the electric utilities sector. As described in Exhibit 2B, Section E8.2, Toronto Hydro plans to address these needs through targeted investments in renewing stations and work centre assets (such as exterior cladding, windows, and roofs where critical equipment is housed), and improvements to security systems (e.g. the installation of network-based cameras and access card readers).

Energy Efficiency and Decarbonization Enhancements: In 2022, natural gas equipment in Toronto Hydro buildings contributed approximately 25% of the utility's total direct greenhouse gas emissions.[1] As detailed in Exhibit 2B, Section D7, Toronto Hydro's goal is to reach Net Zero emissions by 2040. To achieve this important goal in a gradual and paced manner, the utility intends to incorporate equipment swaps (e.g. natural gas to electric) and upgrade its facilities to improve energy efficiency (e.g. through increasing building envelope insulation and LED retrofits) where possible.

D6.3 Longer-Term Planning Considerations

As part of the IPF process, Toronto Hydro evaluates whether property purchases will be required to accommodate the future expansion needs of the distribution system. For example, this may include the need to construct new transformer stations to increase the grid's peak capacity or the siting of other equipment such as energy storage systems to enable the connection and integration of renewable electricity generation facilities. When facilities investments are required to support grid expansion, the Facilities Asset Management team collaborates with the Capacity Planning team to evaluate and integrate facilities investment options and incorporate them into the business case for particular projects, such the Downsview TS business case in the Stations Expansion program (Section E7.4).

The utility owns a small number of municipal stations properties that are decommissioned and no longer functioning to distribute electricity to customers. To determine if these properties can be designated as surplus to be disposed, Toronto Hydro evaluates whether the property is suitable for future grid expansion. The evaluation includes the costs and benefits of a potential sale versus the ongoing property maintenance and operation costs to ensure that the decision to sell or retain the property is financially sound.

[1] Exhibit 2B, Section D7.

Stations buildings house critical distribution equipment such as power transformers and switchgear. When these assets are planned for expansion or major upgrades, Toronto Hydro must also take the necessary steps to ensure that major building systems are functional and up-to-date prior to installing the new equipment. As an example, such systems include building waterproofing and flood management systems that protect electrical equipment and other important structural infrastructure from leaks. Therefore, Toronto Hydro plans and executes investments to support stations upgrades and expansions ahead of major capital projects at stations to ensure safety, reliability, and business continuity.

Similarly, for work centres, Toronto Hydro looks ahead to evaluate if it can accommodate and functionally support future resourcing requirements. As the utility's workforce expands to deliver capital and operations programs and address new requirements and objectives supporting the energy transition, additional work centre investments may be required to accommodate more staff. Those investments have not yet been built into the 2025-2029 plan as the utility continues to evaluate options for its head office strategy, as discussed below.

D6.3.1 Head Office Strategy

The 14 Carlton head office's location in proximity to Union Station and public transit lines enables Toronto Hydro to attract and retains talent from the Greater Toronto Area ("GTA").

The head office building poses several limitations that make its upkeep challenging, noted below:

- **Safety**: the building has an aged standpipe system with fire hose cabinets and no overhead automatic sprinklers, requiring manual fire suppression with a fire hose.
- **Mechanical**: the current heating and cooling system is an outdated 5-pipe system. Limitations on headroom clearance between floors and a controls system past useful life mean that any upgrade to a modern HVAC system would be very costly and challenging.
- **Electrical**: the building's voltage is not up to date with electrical service standards and the building is at its electrical service capacity. Upgrades would require rewiring the building and installing a new vault to upgrade electrical capacity.
- **Historical Site**: the property is designated under Part IV of the *Ontario Heritage Act*, which requires heritage permitting for building envelope repairs. This limits façade projects and repairs and opportunities for modernization (e.g. the installation of modern external HVAC ducting).

- **Layout**: the office layout has been built around the vintage architectural and structural elements, which pose limitations on efficient layouts for workstations, resulting in a less-dense workspace than what would be possible given the available square footage.
- **Environmental:** due to the building's age, it contains hazardous materials, including asbestos, that must be considered in all projects and that incur increased hazard management costs, longer times for project schedules, and business impacts.
- **Energy Efficiency: t**he building's age and structural limitations render it challenging and costly to achieve energy efficiency and decarbonization goals.

Significant renewal investment is required to remediate the risks and deficiencies of the head office. However, in an effort to manage costs responsibly, the Strategy takes a unique approach to this nearly one-hundred-year-old head office, compared to stations buildings of similar age and heritage protection that house critical grid distribution equipment which serves many customers. Over the 2025-2029, Toronto Hydro intends to evaluate options for the long-term investment strategy of the head office. While this analysis is pending, the utility plans to continue with a method of "managed deterioration" at the head office, engaging in reactive stopgap repairs to address safety, ensure compliance with legislative requirements, and maintain business continuity.

D7 Net Zero 2040 Strategy

To mitigate the impacts of climate change, Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to reach "net zero" by 2040.[1]

Toronto Hydro's Net Zero by 2040 strategy builds upon the utility's record of climate action and environmental leadership.[2] Environmental leadership actions include implementing energy efficiency measures at stations and work centres, programs to increase waste diverted from landfills, reducing paper use, and facilitating the installation of renewable energy generation resources and battery energy storage systems for customers and as part of the utility's distribution system.

The City of Toronto (Toronto Hydro's sole shareholder) has declared that climate change is an emergency requiring immediate and sustained action, and has initiated an ambitious plan to achieve net zero community-wide emissions by 2040. Additionally, the Government of Canada passed the *Canadian Net-Zero Emissions Accountability Act*,[3] establishing a legally binding requirement for the federal government to establish a GHG emissions reduction plan for achieving net zero emissions in Canada by 2050.[4] Finally, the Province of Ontario has established a target of reducing GHG by 30 percent below 2005 levels by 2030.[5]

The International Panel on Climate Change ("IPCC") concluded that global warming of 1.5°C is hazardous to humans and natural ecosystems, and should be limited as much as possible. The risks of climate change for Toronto Hydro's operations include more frequent and severe storms and extreme heat, and increased flooding and lightning strikes.[6] These risks significantly endanger the utility's operations and are already manifesting. Severe weather in 2021 caused $2.1 billion of insured damage in Canada, compared to an average of $422 million a year between 1983 and 2008.[7]

[1] The utility's direct or "Scope 1" emissions are primarily emitted by its buildings, its vehicle fleet portfolio, and its sulfur hexafluoride-insulated (SF_6) electrical distribution equipment.
[2] Toronto Hydro, Environmental Performance, https://www.torontohydro.com/about-us/environmental-performance
[3] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22.
[4] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22, ss. 6-7.
[5] Government of Ontario, Climate Change, https://www.ontario.ca/page/climate-change: Target to reduce GHG emissions to 30% below 2005 levels by 2030.
[6] International Panel on Climate Change, IPCC, AR6 Summary for Policymakers at page 14, https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf
[7] Insurance Bureau of Canada, News & Insights, Severe Weather in 2021 Caused $2.1 Billion in Insured Damage, "online", https://www.ibc.ca/news-insights/news/severe-weather-in-2021-caused-2-1-billion-in-insured-damage

Weather events leading to significant outages, such as the wind storm that occurred in May 2022, are anticipated to increase in frequency and severity as the climate continues to change.

Near-term GHG emissions reductions and mitigation actions are critical to reducing the adverse impacts, damages and losses from climate change.[8] To this end, Toronto Hydro is acting to reduce the GHG emissions it produces, with the target of emitting as close to zero emissions by 2040 as possible and purchasing carbon credits or enabling carbon sinks to offset any remaining emissions so that the utility reaches "net zero" direct emissions. Toronto Hydro's primary effort is to reduce its direct GHG emissions and credible offsets will only be used to eliminate remaining GHG emissions if zero direct emissions cannot be attained. The sections below review the three main types of direct emissions that Toronto Hydro produces and the utility's plan to reduce each to net zero by 2040.

With this plan, Toronto Hydro is building on its track record of environmental leadership.[9] Since 2013, the utility reduced its direct GHG emissions by 26 percent by increasing buildings' energy efficiency, minimizing fleet vehicle idling time, and electrifying light-duty fleet vehicles. Toronto Hydro intends to sustain these emissions reductions and implement new initiatives to reduce the remaining emissions to net zero. These investment objectives are part of Toronto Hydro's 2025-2029 investment plan which was put to customers for feedback as part of the Phase 2 Customer Engagement survey.

Toronto Hydro's 2025-2029 custom scorecard includes a measure tracking the utility's progress against a target to reduce 2.6 kilo tonnes of carbon dioxide (CO2) and carbon dioxide equivalents (CO2E) by the end of the rate period. This measure holds the utility accountable to its customers and stakeholders for delivering on the commitment to reach net zero by 2040 to mitigate the impact of climate change.

Toronto Hydro's Vehicle Fleet Emissions

Toronto Hydro's fleet produced 23 percent of its direct emissions in 2022, making this transition strategy a critical component of the utility's net zero by 2040 objective. Toronto Hydro is reducing the emissions produced by its fleet of vehicles by transitioning its procurement standards to prioritize electric and hybrid vehicles whose motors are powered by clean electricity (as per the IESO, over 90

[8] *Supra* Note 6
[9] *Supra* Note 2

percent of Ontario's electricity system is currently emissions-free).[10] Emissions from an electric vehicle are up to 90 percent less than a similarly sized internal combustion engine ("ICE") vehicle.

In addition to decreased emissions, electric and hybrid vehicles are a sound financial investment as they incur lower operational costs due to decreased fuel consumption and vehicle maintenance requirements. The Federal Government has established a price on carbon pollution, which will rise from $65/tonne to carbon dioxide equivalent (tCO2e) in 2023 to $170/tCO2e in 2030.[11] As a result, the price of fuel for ICE vehicles will continue to increase each year. Currently, driving an electric vehicle reduces the annual cost of fuel and maintenance by $1,500 to $2,000 each year. These savings will continue to rise as the price of carbon continues to increase the price of fuel.

Toronto Hydro currently owns and operates 13 electric and 20 hybrid light-duty vehicles. Toronto Hydro plans to continue to purchase fully electric or hybrid light-duty vehicles in a paced manner. Consumer demand and supply chain factors, including manufacturer capability and battery availability, currently pose some limitations on vehicle availability. Toronto Hydro mitigates this risk by using lifecycle assessments to determine when vehicles will need to be replaced and accordingly placing orders for longer lead time purchases of electric vehicles. Toronto Hydro also extends the lifecycle of vehicles to allow time for the procurement of electric or hybrid replacements where the total cost of ownership (including the maintenance costs, replacement costs incurred while the vehicle is unavailable for maintenance, and sunk costs) of extending the vehicle lifecycle does not exceed the estimated total cost of ownership of a new ICE vehicle.

Many vehicle manufacturers are committed to increase the production of electric vehicles and stopping the production of ICE vehicles by 2040.[12] Toronto Hydro's plan to transition to electric and hybrid vehicles protects the utility from manufacturing availability risk and allows the utility to pace its procurement in a fiscally responsible manner that avoids the risk of stranded asset costs.

While manufacturers are committed to increasing electric vehicle production, heavy-duty electric vehicles (such as bucket trucks) remain an emerging technology characterized by a rapidly evolving

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[10] Independent Electricity System Operator ("IESO"), Pathways to Decarbonization Report (15 Dec 22) at page 6, https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization

[11] Government of Canada Federal Benchmark for Carbon Pollution Pricing System, 2023-2030, https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

[12] Accelerating to Zero Coalition, Signatories, Automotive Manufacturers, https://acceleratingtozero.org/signatories-views/

market. As a result, Toronto Hydro cannot yet conclude whether the heavy-duty electric vehicles that are currently available on the market will meet the utility's functional needs and provide sufficient reliability to service the distribution system in emergency situations. As a result, Toronto Hydro is deferring the large-scale transition to fully electric heavy-duty vehicles to the next decade. The utility intends to stage for success of future large-scale adoption of heavy-duty electric vehicle technologies through trials in the 2025-2029 rate period. These trials can enable Toronto Hydro to better understand how this emerging clean technology can be effectively integrated into its critical operations, and to leverage that experience and understanding to support commercial and industrial customers in their fleet electrification journeys.

While the transition to electric vehicles is ongoing, Toronto Hydro will continue to operate and maintain ICE vehicles such as pick-up trucks, cube vans and bucket trucks. Toronto Hydro is using idling reduction technology and biofuels to reduce its fleet emissions in the near term while the utility's fleet still includes combustion engines. Employee communications on electric vehicle use and idling reduction are also used to encourage employees to role model emissions reduction behaviours.

Fleet electrification is discussed in further detail in the Fleet and Equipment capital program (Exhibit 2B, Section E8.3) and the Fleet and Equipment Services OM&A program (Exhibit 4, Tab 2, Schedule 11).

Toronto Hydro's Facilities Emissions

In 2022, the utility's consumption of natural gas at its occupied buildings produced 26 percent of its direct GHG emissions. Toronto Hydro has a paced plan to gradually reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy conservation measures and fuel switching projects. Energy conservation measures include the installation of air curtains and light-emitting diode ("LED") lights to increase the energy efficiency of the utility's buildings. Fuel switching projects include replacing natural gas fueled heaters with electric heating systems. The energy input requirements for an air source heat pump are less than a similarly-sized natural gas system since heat pumps are more efficient.[13] As a result, fuel switching to heat pumps also contributes to the utility's energy efficiency goals in addition to its decarbonization goals.

To smooth and constrain investment profiles, Toronto Hydro intends to take a paced approach to this work, increasing energy efficiency at its buildings to reduce natural gas consumption before fully transitioning from natural gas to electricity. This approach reduces the overall volume of electrical heating and cooling assets that the utility would have to install and provides energy savings through efficiency. Finally, a paced approach enables Toronto Hydro to minimize interruptions to its business operations by effectively scheduling building upgrades and equipment replacements to coordinate with the times the work centres are occupied by employees, rather than conducting the work reactively and interrupting normal business operations. This work must commence in the 2025-2029 rate period in order to execute a paced approach and realize the associated benefits of smoothing the investment costs and minimizing operational disruptions.

Toronto Hydro's plan to reduce natural gas emissions by electrifying buildings' heating and cooling systems puts Toronto Hydro in a position of proactive alignment with current and future government policy developments that restrict or ban natural gas heating. In its Transform TO Net Zero Strategy, the City of Toronto indicated the need to "accelerate a rapid and significant reduction in natural gas use" stating that "catalyzing the electrification of building heating systems, as a preferred alternative to the use of fossil-fuel heating systems, will be key."[14][15] The City further stated in that document that the use of natural gas in buildings must be phased out by 2040 to achieve its net zero targets.[16] Similar policy proclamations could be made by other levels of government if the urgency of climate change action intensifies, and if they are made, Toronto Hydro would be in a position of proactive alignment.

One of the factors Toronto Hydro considered in establishing the plan to reduce emissions from its buildings is the optimal lifecycle of its assets.[17] The optimal lifecycle considers the operational costs of maintaining and operating existing equipment against the cost of capital investments in

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[13] Natural Resources Canada, Publications, Heating and Cooling with a Heat Pump, https://natural-resources.canada.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#b5
[14] City of Toronto, Transform TO Net Zero Strategy, November 2021, Attachment B, p. 8, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf
[15] Ibid.
[16] Ibid, p. 6.
[17] See Facilities Asset Management Strategy, Exhibit 2B, Section D6.

replacement assets on an ongoing basis. Changing maintenance and replacement costs influence the optimal lifecycle cost model. To this end, the rising price on carbon pollution impacts the cost of Toronto Hydro's natural gas consumption. Toronto Hydro's emissions reduction plan can avoid up to $330,000 in carbon tax costs associated with natural gas by 2030, assuming the carbon tax continues to increase annually by $15 per tonne.[18]

The investments required to reduce emissions from buildings are discussed in further detail in the Facilities Management and Security capital program (Exhibit 2B, Section E8.2) and the Facilities Management OM&A program (Exhibit 4, Tab 2, Schedule 12).

Toronto Hydro's Sulfur Hexafluoride (SF6) Emissions

Emissions from Toronto Hydro's SF6-insulated equipment represented 51 percent of its total direct emissions in 2021. Toronto Hydro intends to limit SF6 emissions, and the associated GHG emissions, through the elimination of SF6 leaks from existing distribution equipment and reducing the installation of new SF6-containing equipment where feasible. This plan is intended to minimize the release of potent emissions and prepare for anticipated legislation. SF6 is a potent GHG with a with a global warming potential 22,800 times greater than carbon dioxide. SF6 has been used in electrical transmission and distribution equipment in the electricity industry since the 1950s due to its excellent insulating properties and stability.[19] Toronto Hydro has used sealed SF6 equipment since the 1950s and in some instances, in place of air-vented equipment to mitigate the risk of failure due to ingress of dirt, road contaminants, and flooding. Reliability, safety, and environmental implications are critical considerations in determining the optimal method of eliminating SF6 emissions.

The energy sector is under increased pressure to reduce reliance on SF6 because it is a potent GHG. Legislation is expected to limit the use of SF6 in the future. Such legislation has already been implemented in other jurisdictions, including California.[20] Proactively minimizing the use of SF6 reduces Toronto Hydro's operational risks, as replacement costs would be material if Toronto Hydro were required to comply with new legislation on short notice, increasing the risk of stranded assets and operational replacement costs.

[18] *Supra*, Note 11.
[19] United States Environmental Protection Agency, Sulfur Hexafluoride (SF6) Basics, "online", https://www.epa.gov/eps-partnership/sulfur-hexafluoride-sf6-basics
[20] California Air Resources Board, Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment, Title 17, "online", https://ww2.arb.ca.gov/sites/default/files/2022-05/gie21-final-regulation-unofficial.pdf

Toronto Hydro plans to install assets that use alternatives to SF6, such as solid dielectric transformers, in order to meet its Net Zero 2040 target and prepare for any anticipated legislation. The utility's approach addresses challenges associated with eliminating SF6 emissions, including leak detection difficulties and a lack of operationally suitable alternatives. Toronto Hydro identified alternatives, such as solid dielectric equipment, for approximately 75 percent of existing SF6 applications. However, the balance of approximately 25 percent cannot be replaced at this time as the currently available alternative equipment does not have sufficient rating for the required electrical current. As a result, Toronto Hydro must take a two-pronged approach to mitigating SF6 emissions:

1. Eliminate SF6 use where operationally feasible; and
2. Improve leak prediction and detection capabilities to address SF6 emissions proactively.

This approach is embodied in Toronto Hydro's Underground System Renewal – Horseshoe capital program, discussed in Exhibit 2B, Section E6.2. This program details the investments that Toronto Hydro intends to make in solid dielectric switchgear to try it as an alternative option to SF6-insulated switchgear.[21]

Toronto Hydro is committed to eliminating SF6 by installing alternatives in all new construction projects where doing so is operationally feasible and where physical space, cost, design standards, and equipment availability allow Toronto Hydro to trial viable alternatives to SF6 insulated equipment. The utility is also exploring other insulation alternatives to SF6 gases; however, these gases are not currently widely deployed by other utilities and remain at the pilot stage.

Toronto Hydro also continues to improve leak prediction and detection capabilities to address SF6 emissions proactively.[22] The utility investigates the cause of failures in SF6 equipment to identify trends and enhance the inspection process to allow greater focus on common failure points. The investigation data also allows Toronto Hydro to identify the equipment types and manufacturers that are experiencing quality issues and select vendors that supply more reliable equipment. The utility communicates the common failure points identified through investigations to manufacturers to improve the manufacturing process. For example, when the investigation process identified multiple leaks from bushings related to welding issues, Toronto Hydro worked with the relevant manufacturer

[21] Underground System Renewal – Horseshoe, Exhibit 2B, Section E6.2, p. 31.
[22] Preventative and Predictive Maintenance – Underground, Exhibit 4, Tab 2, Schedule 2, Page 2 & 24; Preventative and Predictive Maintenance – Stations, Exhibit 4, Tab 2, Schedule 3, Page 3

to improve the welding inspection process prior to equipment delivery. Additionally, the utility installed SF6 leak detection alarms for some equipment. These alarms provide early notification when a leak condition exists and enable rapid mitigation of impacts to the environment.

Conclusion

The 2025-2029 investment plan supports Toronto Hydro's Net Zero 2040 by strategy through investments in the electrification of Toronto Hydro's fleet and buildings, enhancements to building envelope efficiency, and elimination of SF6 emissions from equipment. These investments mitigate business continuity risk and manage long-term costs associated with decarbonization policies, such as the federal tax on carbon emissions. Deferring these investments to future periods would entail greater disruption to business operations, thereby increasing expenses and hampering productivity. Paced decarbonization investments also protect Toronto Hydro and its ratepayers against the risk of sudden legislative changes governing the use of SF6 gas and phase-outs of ICE vehicles which could require corporations like Toronto Hydro to decarbonize their emissions in an accelerated manner.

D8 Information Technology Investment Strategy

Informational technology ("IT") is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management and Investment Planning Strategy (the "Strategy") is to derive sustainable value from IT assets for the utility and customers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner and effectively mitigate ongoing risks (e.g. impacts of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enables Toronto Hydro to achieve this key objective.

IT asset management includes the purchase, operation, maintenance, renewal, replacement and disposition of IT data, hardware, and software assets. IT asset management is defined by IT standards, and includes:

- Requirements for data, hardware, and software assets (e.g. physical, performance, compatibility, security, etc.);
- IT architecture establishes expected service levels (e.g. performance measurement, reliability requirements, incident / problem management for the assets); and
- Lifecycle management schedules for each type of asset.

Sustainment is necessary for maintaining the functionality and currency of existing IT systems. Enhancement involves improving existing systems and facilitating their organic growth requirements, such as meeting the needs of increasing numbers of staff or customers. Transformation refers to implementation of new systems or modules that add new business capabilities, provide higher protection levels for digital assets and safeguard customer and employee privacy.

To enable the Strategy, Toronto Hydro uses well-defined IT standards and up-to-date IT asset information. To that end, the utility uses an internal framework which provides high-level criteria to consider in the IT investment decision-making process. The process leads to the development of a five-year roadmap of prioritized investments, including a detailed plan for the first year.

D8.1 IT Asset Management

Toronto Hydro developed IT standards to streamline and optimize the lifecycle of IT assets, define system architecture, and gain operational efficiencies through the standardization of IT assets and components. The utility defines its IT standards based on information provided by equipment vendors (e.g. statistics on mean time to failure), internal historical data regarding asset failures, and industry best practices, and reviews its IT standards regularly to ensure that they remain current and relevant for the utility.

Toronto Hydro adopted distinct yet mutually reinforcing IT standards and architecture for data, hardware, software, security, assets and standards for processes (e.g. testing, monitoring and alerting), as described in greater detail below. For example, having aligned hardware and software standards enables the utility to implement virtualized hardware platforms—a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine.

The virtualization of the infrastructure provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies;
- Simplified monitoring of IT assets;
- Enhanced security; and
- Easier migration to new hardware and technology, including cloud solutions where required.

D8.2 IT Hardware Standards

IT hardware standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include resource forecasting, procurement management, life cycle management, redeployment, and disposal management. Toronto Hydro applies these practices to the categories of hardware assets described in Figure 1 below.

Core Backend Infrastructure Assets

- Responsible for the computation, storage and communication necessary to support IT systems:
- **Computing**: servers and security appliances;
- **Storage**: disk arrays, flash arrays, backup systems; and
- **Communication**: network and telephony assets.

Endpoint Assets

- Enable end-users to execute, process, complete and review business tasks and operations:
- **Computing:** desktops, laptops and tablets;
- **Printing**: printers and plotters; and
- **Communication:** desk phones, mobile phones.

Figure 1: IT Hardware Asset Categories

IT hardware and architecture standards specify which types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of these different assets.

The utility must periodically refresh IT Hardware assets to guarantee expected service levels of the systems and minimize the risk of asset failure and impact to the business or customer services (e.g. from the failure of assets supporting customer-facing applications such as the self-service portal or outage map). Through its IT hardware standards, Toronto Hydro seeks to define the optimal timing of asset replacement such that the utility operates hardware assets with the lowest acceptable failure rate at optimal costs. As illustrated in Figure 2 below, the lifecycle of IT assets generally follows a “bath tub curve” that breaks out into three distinct regions:

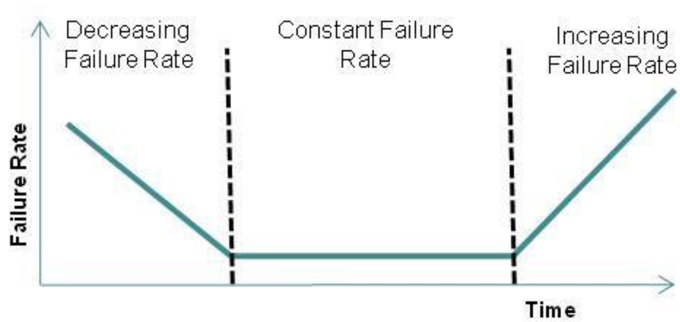

Figure 2: IT Hardware Asset Lifecycle Failure Rate over Time

- **Decreasing Failure Rate:** This is the region of the curve associated with a reduced failure rate over time. This is typical in the release of a new product, where once upfront implementation issues and defects are addressed, failure rates tend to drop.
- **Constant Failure Rate:** As a failure rate decreases to a certain low point, it stabilizes and remains virtually constant. The cost of ownership in this area of the bathtub curve is steady and financially optimal.
- **Increasing Failure Rate**: As the product ages beyond useful life, its failure rate starts to increase again due to general operational wear and tear. As a result, system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practices, and vendor specifications, IT hardware standards define the optimal time for asset replacements before reaching the "Increasing Failure Rate" portion of the lifecycle. This approach minimizes the risk of interruption to the core processes and technology that Toronto Hydro relies on to execute its capital plans and operational programs. This approach also helps the utility incur IT-related operational and capital expenditures prudently and at reasonable levels, while also increasing the flexibility to adapt IT infrastructure in accordance with customers' evolving needs and preferences and changing business circumstances.

D8.3 IT Software Standards

Toronto Hydro categorizes its software applications as Tier 1, Tier 2 and cloud-based solutions. The criteria used to classify these applications include the level of impact on critical business functions, system complexity, maintenance costs, and the number of application users.

- **Tier 1** applications enable Toronto Hydro's critical business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex, highly redundant underlying infrastructure such as databases, middleware, storage, and network. As a result, Tier 1 applications generally have higher maintenance costs and a larger user base than Tier 2 applications. Examples of Tier 1 applications include the Enterprise Resource Planning System, Network Management System, and Geospatial Informational System.

- **Tier 2** applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications, and are typically supported by infrastructure with a lower complexity and lower target for overall availability. Tier 2 applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. For example, several of Toronto Hydro's operational divisions use ProjectWise as a document management system. Another example of a Tier 2 system is Power Monitoring Expert, used by the utility's engineers to provide insights into electrical system health and energy efficiency.

- **Cloud-based** applications enable both company-wide and specific business processes. The unique feature of a cloud-based solution is that it resides on vendor infrastructure and is accessed through the internet. Toronto Hydro establishes system service level agreements with each cloud service provider to set service conditions, e.g. relating to business continuity and cyber security. An example of a cloud-based application is Intelex which Toronto Hydro uses to manage health and safety inspections and incident reporting processes. Another example is Oracle Field Services Cloud (OFSC), a mobile workforce management system that allows dispatchers and field crews to collaboratively manage major events, assemble crews, manage priorities, and communicate across different groups to respond to major events in a timely and effective manner.

Toronto Hydro enhances system functionality, reduces the risk of system failures and cyber security breaches, and aligns its software assets with vendor support cycles through regular software upgrades. Continuing to run and rely on software applications beyond the end of vendor support increases the risk to system reliability and of greater exposure to cyber security threats. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may need to procure specialized technical resources to maintain and support the application. Timely software upgrades also help reduce unforeseen IT-related operational and capital expenditures by minimizing the risk of asset failure.

Through its IT software standards, Toronto Hydro seeks to maintain the compatibility of software applications with the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Since many IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility among various software applications can be a complex task. Nonetheless, it is a key consideration in mitigating security and reliability risks to IT systems from the underlying components.

Toronto Hydro's IT software standards consider average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Through the application of the Strategy, the utility implements software asset upgrades depending upon need and risk factors, including where the asset reaches its maximum age or is more than one version behind the latest vendor-released version, or based on specific compatibility drivers and considerations (e.g. hardware upgrades).

D8.4 IT Cyber Security Standards

With the emergence of advanced persistent threats and nation-state actors, advanced cyber security attacks against critical infrastructure are becoming more widespread. The proliferation of a large number of potentially exploitable internet of things (IoT) devices (e.g. for home automation) enables attackers to form "botnets" to perform large-scale distributed denial of service (DDoS) attacks against enterprises.[1] Furthermore, the advent of cryptocurrencies has led to the emergence of ransomware attacks that extort organizations by encrypting critical data and demanding for ransom payments in untraceable cryptocurrencies.

The primary role of Toronto Hydro's cyber security practice is to maintain a strong cyber security posture through a combination of sustaining existing systems and enhancement initiatives, commensurate to the perceived threat level and the organization's risk tolerance.

The utility sustains existing systems with the maintenance and organic and strategic growth of existing information security capabilities. From the threat, risk and compliance perspective this includes the orchestration of recurring enterprise IT asset security patching as well as lifecycle upgrades of perimeter and endpoint security controls, such as firewalls, intrusion prevention systems and malware protection software. The identity access management aspect of the program ensures that the organization maintains secure, role-based access to resources, and proper logging for audit and forensic analysis purposes.

Toronto Hydro's enhancement initiatives expand baseline cyber security capabilities through the adoption of advanced threat protection technologies and user education processes aimed at curbing

[1] The internet of things (IoT) refers to the interconnected network of physical devices, vehicles, home appliances, and other items embedded with electronics, software, sensors, and connectivity which enables these objects to collect and exchange data. The IoT allows these devices to communicate with each other and with a centralized system, enabling them to perform a wide range of tasks and functions without human intervention

the exposure to social engineering attacks. The utility explores pioneering technologies and cyber defence mechanisms to ensure the security of its digital assets and safeguard the privacy of customer and employee personal information and gain stakeholder confidence.

Pursuant to the Strategy, Toronto Hydro requires all systems delivered through sustainment, enhancement, and transformation initiatives beyond cyber security-specific initiatives, to meet stringent standards that are aligned with the Ontario Energy Board Cyber Security Framework and stipulated within the utility's application security, network security, cloud security, data security and endpoint security standards. This ensures a strong cyber security posture for every system deployed within or for Toronto Hydro.

D8.5 IT Investment Planning Process

IT investment planning is the process of developing, prioritizing, and managing a continuous five-year roadmap of investments, including a detailed project plan for the first year. As part of the Strategy, Toronto Hydro developed an Enterprise Technology Portfolio (ETP) framework to ensure consistency in IT investment decisions, establish and maintain governance of investments and achieve alignment with the utility's strategic objectives and target outcomes. The capital and cloud (OM&A) expenditures detailed in Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17, reflect the roadmap for the next rate period.

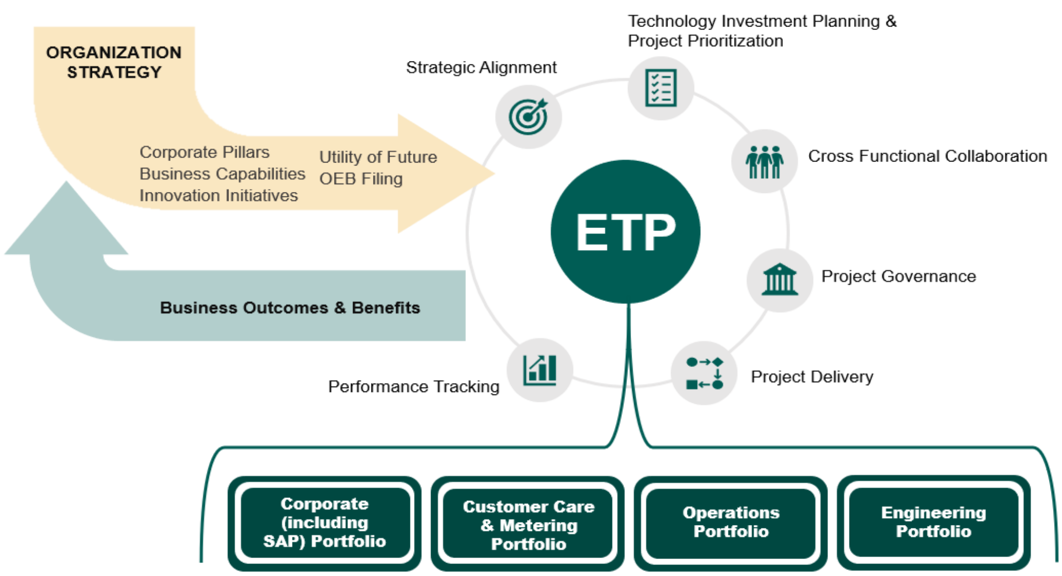

Figure 3: Enterprise Technology Portfolio Framework

D8.5.1 Enterprise Technology Portfolio (ETP) Framework

Through the ETP framework, the utility centralizes the intake of all technology requests from across the organization, plans IT investments and prioritizes initiatives and projects in accordance with the Strategy. In prioritizing initiatives and projects, the utility considers:

- Operational factors such as IT asset lifecycle, business impacts, change management, resource availability, and internal and external project dependencies.
- Financial factors such as costs versus benefits and approved budgets
- External factors such as IT industry best practices and trends, utility industry trends, vendors' information, and trends of evolving regulatory and compliance requirements are also taken into consideration as needed.
- Strategic alignment with key investment priorities and objectives established through the utily's integrated planning process detailed in Section E2.

Based on these inputs, ETP roadmaps are designed with the following objectives:

(i) Enabling technology investments that advance business and customer outcomes;
(ii) Ensuring optimal levels of IT system reliability and availability; and
(iii) Compliance with the utility's IT standards.

Each roadmap includes a detailed plan for the first year and provides a higher-level plan for the remaining period. This agile approach provides necessary certainty and precision for the implementation of near-term initiatives, and high-level parameters for longer-term initiatives, giving the utility the ability to respond effectively to changes in external drivers and risks, such as:

(i) Fluctuations in software and hardware costs;
(ii) Changes in the release dates of certain applications;
(iii) New technology products disrupting the marketplace and industry;
(iv) New threats, vulnerabilities, or modes of cyber security attacks;
(v) New or evolving requirements from regulatory bodies such as the Ontario Energy Board, Measurement Canada and the Independent Electricity System Operator (IESO); and
(vi) Changes in industry best practices such as the adoption of cloud solutions.

Toronto Hydro maintains a flexible and agile approach by continually balancing its roadmap against the strategic objectives of the organization for the planning period. For example, to support grid modernization during the 2025-2029 rate term, Toronto Hydro intends to prioritize projects that enable monitoring and operational capabilities of its distribution system. Examples of such efforts will include installing enhanced communication infrastructure, introducing advanced grid configurations, enabling enhanced monitoring, automation and remote control, and providing greater insight into the grid operations through analytics into grid performance and grid reliability. For more information on these types of investments, please refer to the Grid Modernization Strategy at Exhibit 2B, Section D5 and the Advanced Distribution Management System Business Case in Exhibit 2B, Section E8.4, Appendix A.

D8.5.2 Project Governance Framework

Beyond the ETP framework, the utility relies on a formal business case for the governance and approval for projects within the one-year window. Stakeholders from various functions in the organization collaborate in the creation, review, and approval of each business case. This process includes business units, IT functional and technical teams, IT security teams and change management professionals. Stakeholders' inputs determine the scope, business requirements, current state business processes, future state business processes, options analyses, the preferred approach and the associated costs and benefits. Once the business case is approved, the project proceeds to execution. Toronto Hydro uses a robust project management framework to manage and oversee the progress of the project against key parameters such as the approved budget, scheduled, scope, identified risks and target benefits.

D8.5.3 Evaluation of Options

With the emergence and increasing availability of cloud-based solutions, Toronto Hydro deploys the Strategy to evaluate multiple options to meet business needs, including cloud-based solutions such as software-as-a-service, platform-as-a-service, and infrastructure-as-a-service. For each project, the utility grounds its investment decisions on a rigorous and consistent comparison and evaluation of on-premise and cloud-based solutions, with reference to various criteria such as: transformation potential, rollout velocity, the size of the solution, the business criticality of the underlying functions, data and cyber security considerations, the flexibility of adopting new features, the window of available vendor maintenance, and the total cost of ownership.

For example, when considering projects implemented in 2020-2024 for critical grid management systems, such as Network Management Systems, Toronto Hydro completed a detailed analysis and determined that the on-premise solution in these cases provided the optimal outcomes. This decision was based on the business criticality of these systems in managing the grid and the high degree of sensitivity to cyber security risks. Another key factor that informed the utility's decision was the need for flexibility in maintenance windows to avoid operational interruptions due to unplanned events such as storms.

In a different example, Toronto Hydro implemented a cloud-based solution to support its enterprise health and safety business processes. The utility selected this solution over any available on-premise alternatives because unlike on-premise alternative, the selected cloud-based solution required limited integration to other Toronto Hydro systems and offered the ability to adopt new industry best practices in a shorter period of time. From a cyber security standpoint, the selected solution does not house sensitive health and safety information, which limits the risk exposure to an acceptable level. From a financial standpoint, the utility determined that the total cost of ownership for the cloud solution would be lower than the implementation of a comparable on-premise solution. Cumulatively, these considerations led Toronto Hydro to select a cloud-based solution to support its enterprise health and safety processes.

Toronto Hydro Enterprise IT Cost Benchmark & Functional Maturity Assessment

Final Report

June 5, 2023

Engagement Number: 330079917

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01
Summary of Findings

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TH's 2022 IT spend as a % of Revenue has increased since 2017, however is very similar to the peer group average; higher spend levels are due to inflation, investments in digital transformation and maturing IT's capabilities

- Toronto Hydro was compared to a peer group of eight utility organizations with similar revenue and operating expenses, with a major focus of electricity distribution in major urban centers
- Toronto Hydro's 2022 IT Spending as a % of Revenue was 3.2% compared to an average of 3.0% for the peer group, and 3.3% of OpEx compared to 3.9% for the peer group. The $28 million IT spending increase in 2022 over 2017 was due to inflation (~$10 million), increasing Operational Expenses (i.e. ERP support, cloud services, cyber security) and investments in the Customer Information System.
- Increase in IT Spending over 2017 is similar to industry peers
- In 2022, Toronto Hydro allocated 11% of IT Spending to "transform", almost three times more than in 2017. This is the result of investments in digital transformation.
- Toronto Hydro's IT staffing levels are materially lower than the peer group average (5.8% IT FTEs as a % of total Employees** versus 8.2%). IT Staffing levels as a % of total Employees** has decreased slightly from 6.2% in 2017.

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend as a % of Revenue						
- Operational	1.5%	$55.2	1.0%	$39.2	1.8%	2.0%
- Capital	1.7%	$59.6	1.2%	$47.9	1.2%	1.0%
- Total	3.2%	$114.8	2.2%	$87.1	3.0%	3.0%
IT Spend as a % of OpEx						
- Operational	1.6%	$55.2	1.1%	$39.2	2.3%	2.4%
- Capital	1.7%	$59.6	1.3%	$47.9	1.6%	1.3%
- Total	3.3%	$114.8	2.4%	$87.1	3.9%	3.7%
Run, Grow, Transform*** (% of total IT Spend)						
- Run %	71%	$81.1	71%	$61.8	65%	70%
- Grow %	18%	$21.2	25%	$21.8	20%	18%
- Transform %	11%	$12.4	4%	$3.5	15%	12%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT FTEs as a % of Employees**	5.8%		6.2%		8.2%	6.8%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)
** This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors
*** See page 31 for "Run, Grow, Transform" definitions
[1] Average Canadian Consumer Price Index increase 2017-2022
Note: Totals may not equal due to rounding

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TH's focus on digital transformation has meant a higher allocation to applications spending; IT spending by cost category is balanced and in line with peer organizations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of growth and transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million. This can be largely attributed to Customer Information System upgrades.
- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.
- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.1% of IT spending in 2022) is virtually the same as the peer group.
- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend Distribution by Area						
- Enterprise Computing	14.7%	$16.9	25.0%	$21.8	14.6%	15%
- Voice & Data Network	9.5%	$10.9	9.5%	$8.3	19.8%	12%
- Workplace Services	6.9%	$7.9	6.1%	$5.3	9.2%	7%
- IT Service Desk	3.0%	$3.4	2.3%	$2.0	3.8%	3%
- Application Development	24.7%	$28.4	46.9%[2]	$40.8	18.9%	25%
- Application Support	26.5%	$30.4			23.0%	21%
- Governance & Ser. Mgmt.	5.9%	$6.7	10.3%[3]	$9.0	4.6%	8%
- IT Security	5.7%	$6.5			2.4%	4%
- IT Ops. Mgmt.	2.8%	$3.2			3.2%	3%
- Ser. Con't / DR	0.4%	$0.5	_	_	0.6%	1%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT Spend per Cost Category						
- Outsourcing	21.3%	$24.4	19.9%	$17.3	26.6%	26.0%
- Personnel	33.4%	$38.4	39.8%	$34.7	26.6%	31.0%
- Software	31.1%	$35.7	27.6%	$24.0	31.9%	30.0%
- Hardware	14.1%	$16.2	12.7%	$11.1	14.9%	13.0%
- Total	100%	$114.8	100%	$87.1	100%	100%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)
[1] Average Canadian Consumer Price Index increase 2017-2022
[2] 2017 Application Development includes Application Support
[3] 2017 Governance & Service Mgmt. includes IT Security, IT Ops Mgmt. and Service Continuity / Disaster Recovery
Note: Totals may not equal due to rounding

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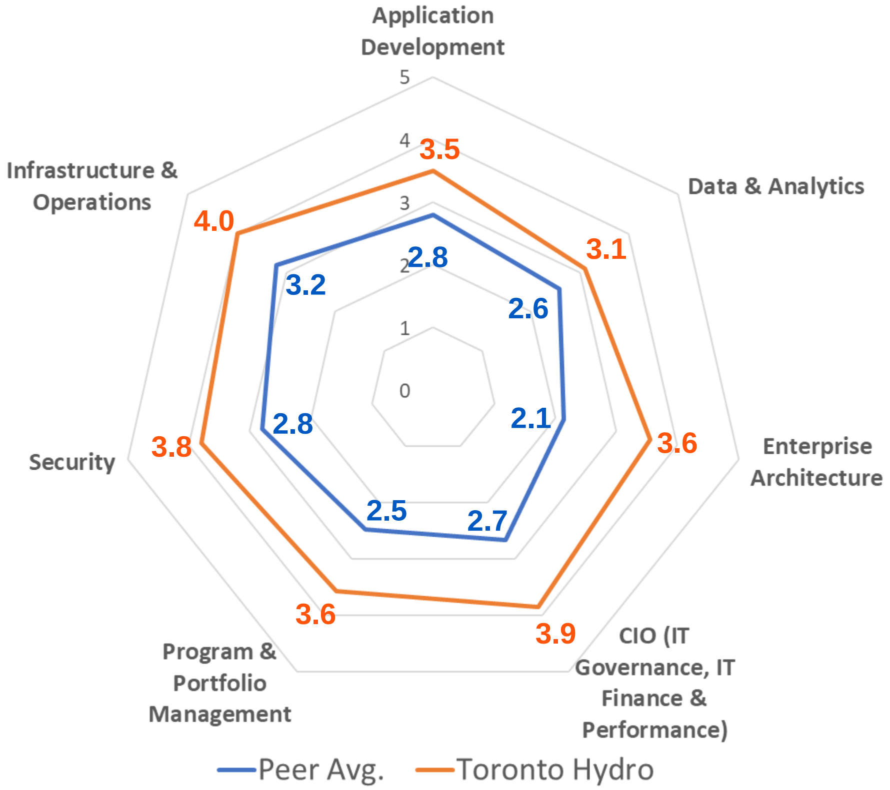
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

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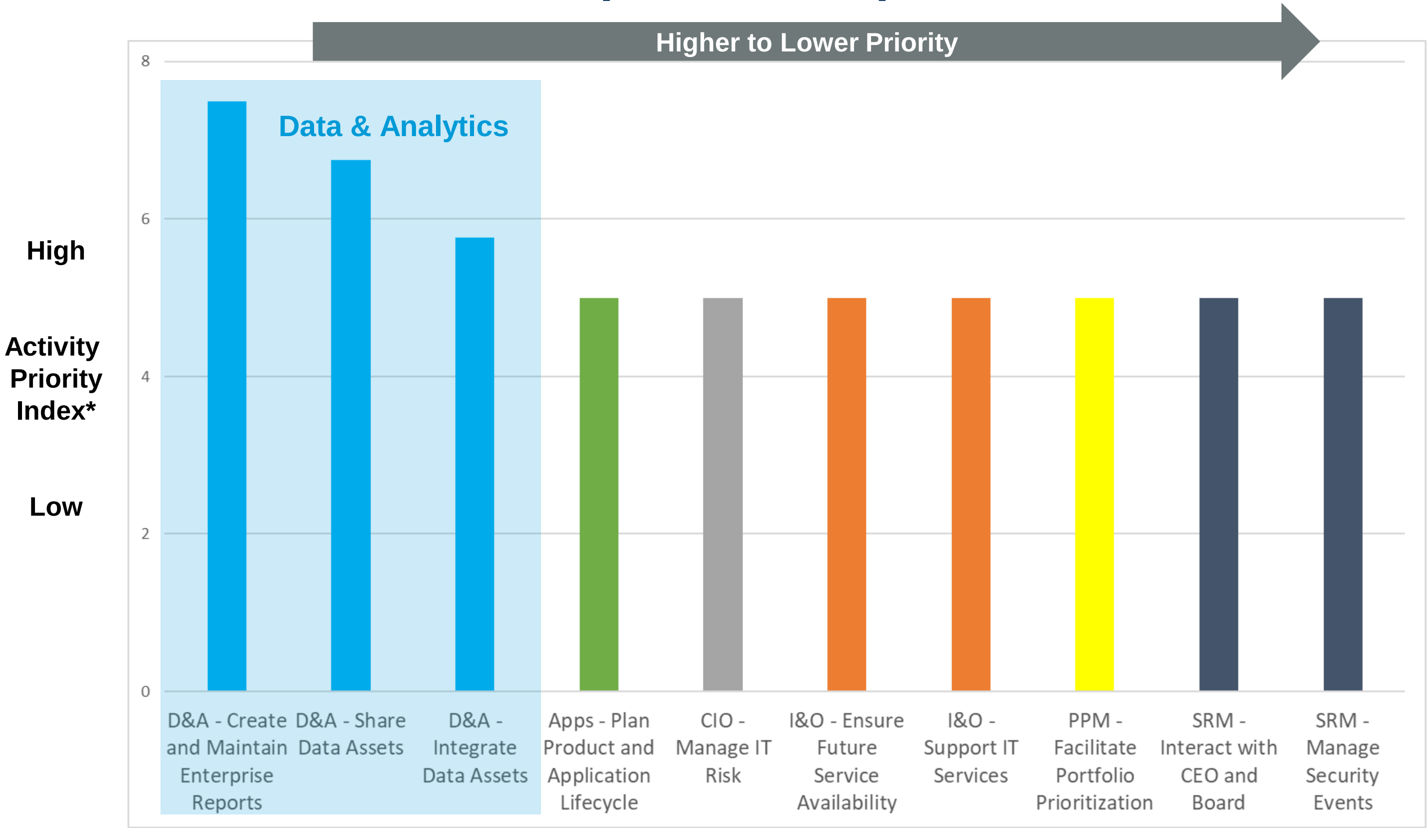
Based on maturity assessment results, opportunities for improvement exist in each domain, however improving Data & Analytics capabilities would add the most value to Toronto Hydro

- 38 of 64 functional activities had a positive Activity Priority Index meaning there is value to Toronto Hydro in improving the capability
- Each in-scope domain had a number functional activities identified for improvement:
  - Chief Information Officer (CIO)[1] = 7
  - Applications = 3
  - Data & Analytics = 5
  - Enterprise Architecture = 5
  - Infrastructure & Operations = 5
  - Program & Portfolio Management = 7
  - IT Security = 6
- When relative importance is considered, improvements to the maturity of the Data & Analytics domain would add the most value to Toronto Hydro

[1] includes Managing IT Governance, Managing IT Finance and Managing Performance

Top 10 Areas for Improvement



***Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.**

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02
Objectives and Approach

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Gartner understanding of business context and objectives

Context

- Toronto Hydro wanted an independent and objective expert assessment of process maturity of its IT functional areas and to establish a reliable baseline of its overall IT spend and staffing position relative to comparable peer organizations.
- In the short-term, these maturity and cost baseline assessments would provide a fact-based action plan for the organization's regulatory filing and catalyze a roadmap of initiatives that Toronto Hydro's IT Leaders will drive to advance maturity and efficiency levels consistent with Toronto Hydro's Business and IT strategic objectives.
- Longer term, these maturity and cost baseline assessments would form the basis for a transformational strategy as a result of the current state baseline and recommendations of this annual effort.
- Gartner's insights and recommendations will highlight IT capabilities needed for Toronto Hydro to align to existing organizational strategies, increase the pace of value being brought to the business, and enable the promise for future transformational aspirations.

Engagement Objectives

Gartner combined several unique and proprietary Gartner assets and capabilities that give Toronto Hydro a fact-based, objective starting point for its ongoing strategic direction. These capabilities include:

- Gartner Research maturity models aligned to key capability areas that integrate Gartner Research insights and industry leading frameworks to support maturation objectives.
- Gartner's world-leading IT Benchmark database to support a fact-based comparison, using a custom-built peer group to Toronto Hydro's environment, to anchor the current state in key IT enterprise-level cost and staffing measures.

Outcomes of the engagement will include:

- A current state summary of Toronto Hydro's maturity across the organization
- A current state summary of Toronto Hydro's IT spend and staffing levels relative to peers with a comparable environment that will identify optimization opportunities to focus future strategic efforts.
- A set of prioritized recommendations based on the comparative analysis that will advance Toronto Hydro in areas directly impactful to the to IT and business objectives.
- Guidance on appropriate re-measurement periods and the foundation to measure progress objectively.

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Gartner conducted an IT assessment that included a review of process maturity of key IT functions and an enterprise-level benchmark of IT spend and staffing relative to peers

PROCESS MATURITY

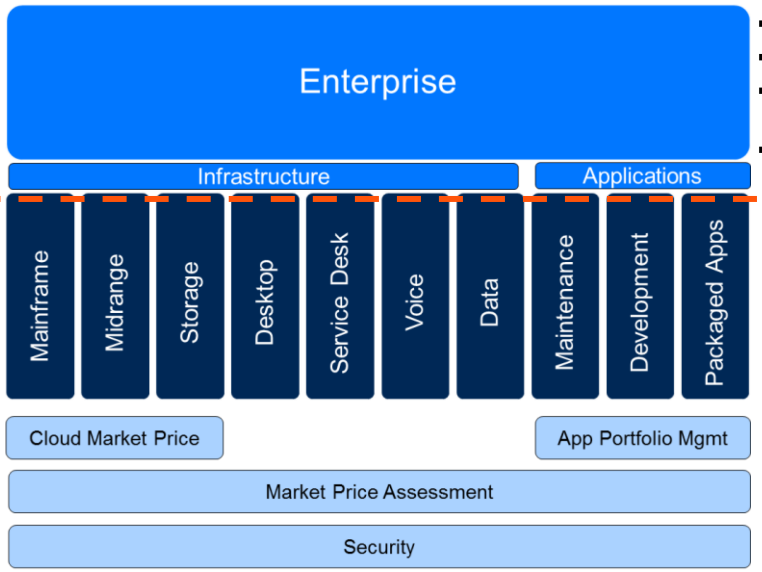
+

SPEND AND STAFFING

Scope of Assessment

Current State Assessment of IT Process Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grown / Transform

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03 Enterprise IT Spending & Staffing Analysis

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3.1
IT Spending & Staffing Benchmark – Methodology Overview

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Toronto Hydro’s IT Assessment focuses on process maturity and spending and staffing as compared to peer organizations

Section 3.0 Focus

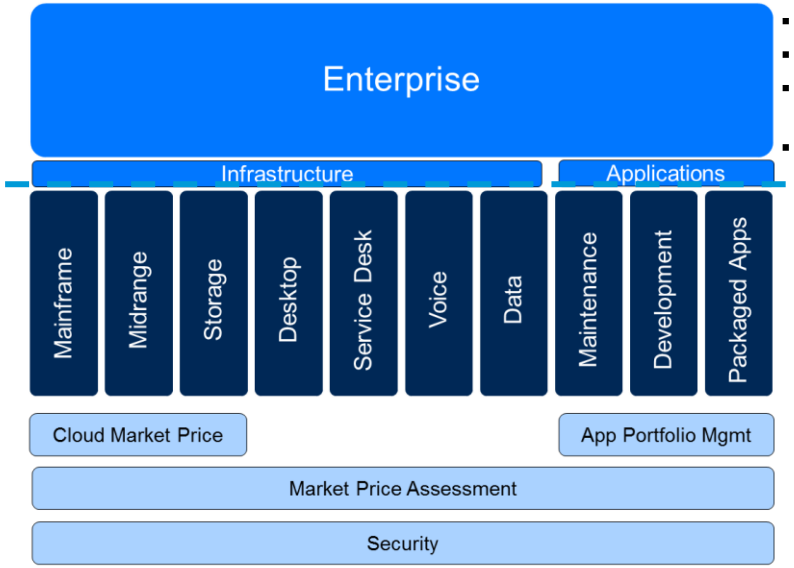
PROCESS MATURITY

+

SPENDING AND STAFFING

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

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Spending & Staffing Benchmark Methodology Overview

Gartner used its industry-leading benchmarking consensus models to evaluate total IT Spending and Staffing relative to a hand selected group of industry peers and IT Key Metrics Data for the Utilities industry.

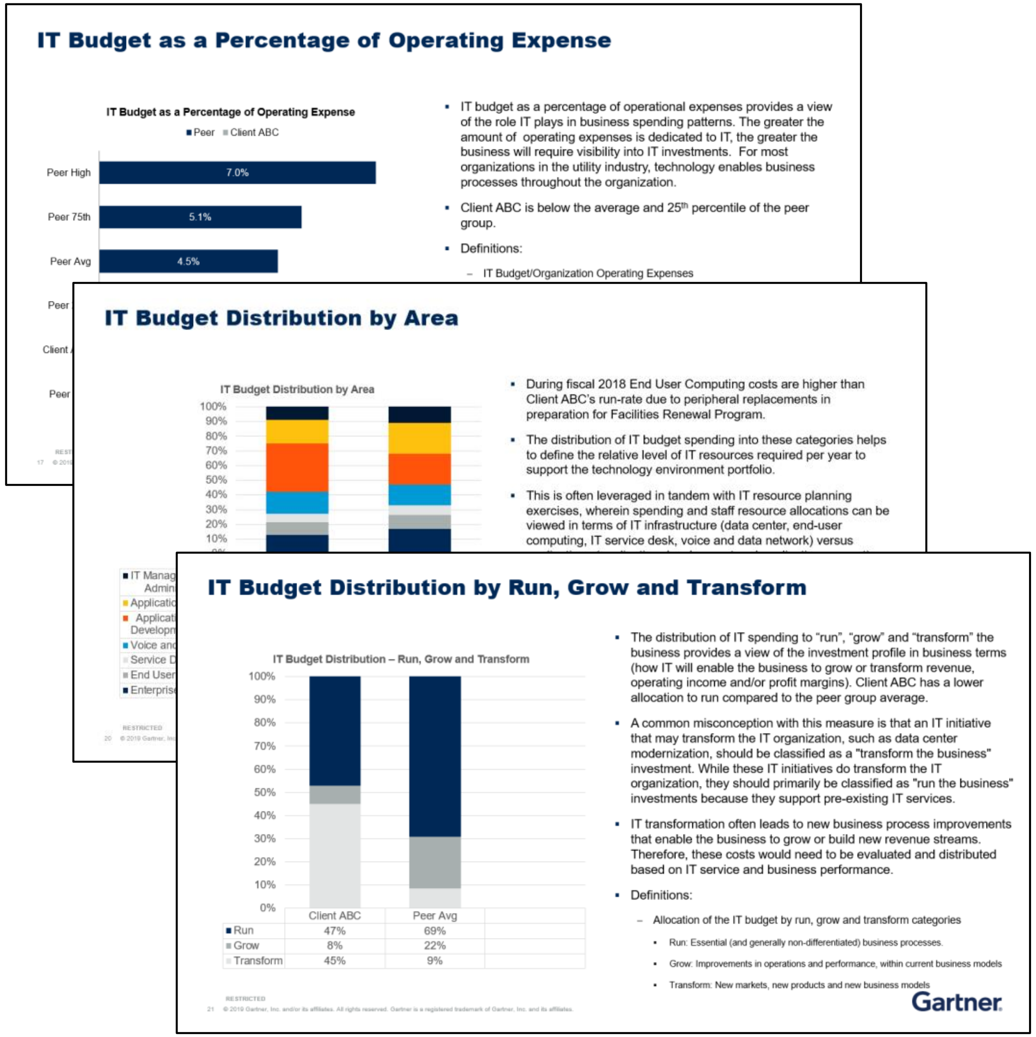
The Enterprise View: IT Spending and Staffing Assessment analysis will provide and compare the following metrics:

Spending Measures

- IT Spending as a % of Revenue
- IT Spending as a % of Operating Expense
- IT Spending Per Employee
- Capital vs. Operational Spending
- Run vs. Grow vs. Transform Spending
- Distribution of IT Spend—Hardware, Software, Personnel, Outsourcing, Other
- Distribution of IT Spend—by IT Function

Staffing Measures

- IT Staff as a % of Company Employees
- Distribution of IT Support—by IT Function



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3.2
Enterprise IT Spending & Staffing Benchmark Results

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Analysis Notes

- Toronto Hydro's data submission for this benchmarking engagement includes:
  - 2022 actuals for Revenue, Operating Expenses and Total Employees
  - 2022 actuals (January to December) for IT Spending & Staffing

- 2017 Toronto Hydro & Peer IT Spending & Staffing data was taken from Gartner's "IT Budget Assessment Final Report" dated March 16, 2018

- Peer Group data is from 2020-2022

- Gartner's IT Key Metrics Data (ITKMD)* is from 2021

* ITKMD is a Gartner Benchmark Analytics solution that delivers indicative IT metrics in a published format as directional insight for IT organizations. This solution represents a subset of the metrics and prescriptive capabilities that is available through Gartner Benchmark Analytics.

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Peer Group Profiles

Selection Criteria	
Primary Criteria	Utilities Industry
Secondary Criteria	Nature of Business (electricity focused, includes distribution within major centers), Total Revenue, Total Operating Expenses, # of Employees and Geography

Custom Peer Group Profile		
Number of Organizations	8	
Geographical Location	Canada, USA, Europe, South America, Australia, New Zealand	
	Toronto Hydro*	**Peer Group Average**
Total Revenue	**$3.60 Billion**	**$3.63 Billion**
Total Operating Expense	**$3.48 Billion**	**$3.08 Billion**
Total Employees	**1,245**	**2,890**

2021 IT Key Metrics Data (ITKMD) Utilities
123
Utilities
Global
2021 ITKMD

* Toronto Hydro data is for fiscal year ending December 31, 2022
** All analysis is in Canadian dollars, using the exchange rate of 1 USD = 1.277 CAD

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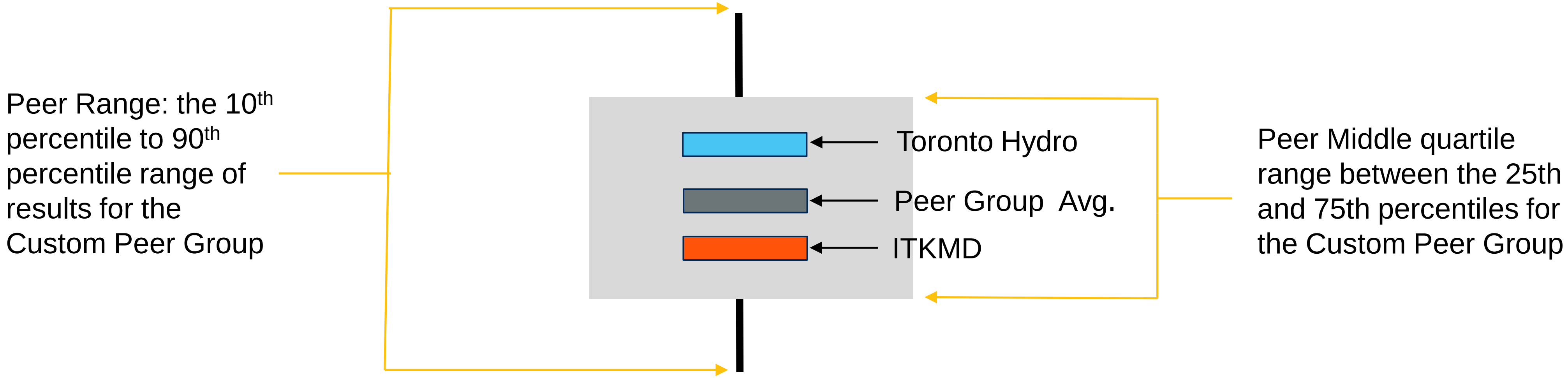
Benchmark Analysis Methodology
Peer Comparisons

Toronto Hydro's results are displayed in comparison with the following reference points:



There are not necessarily "good" or "bad" results for any individual metric.

Differences in spending and staffing metrics derived from this analysis provide insight into current strategic IT investment levels versus your competitive landscape.

These measures should also be considered within the context of your future state organizational objectives.

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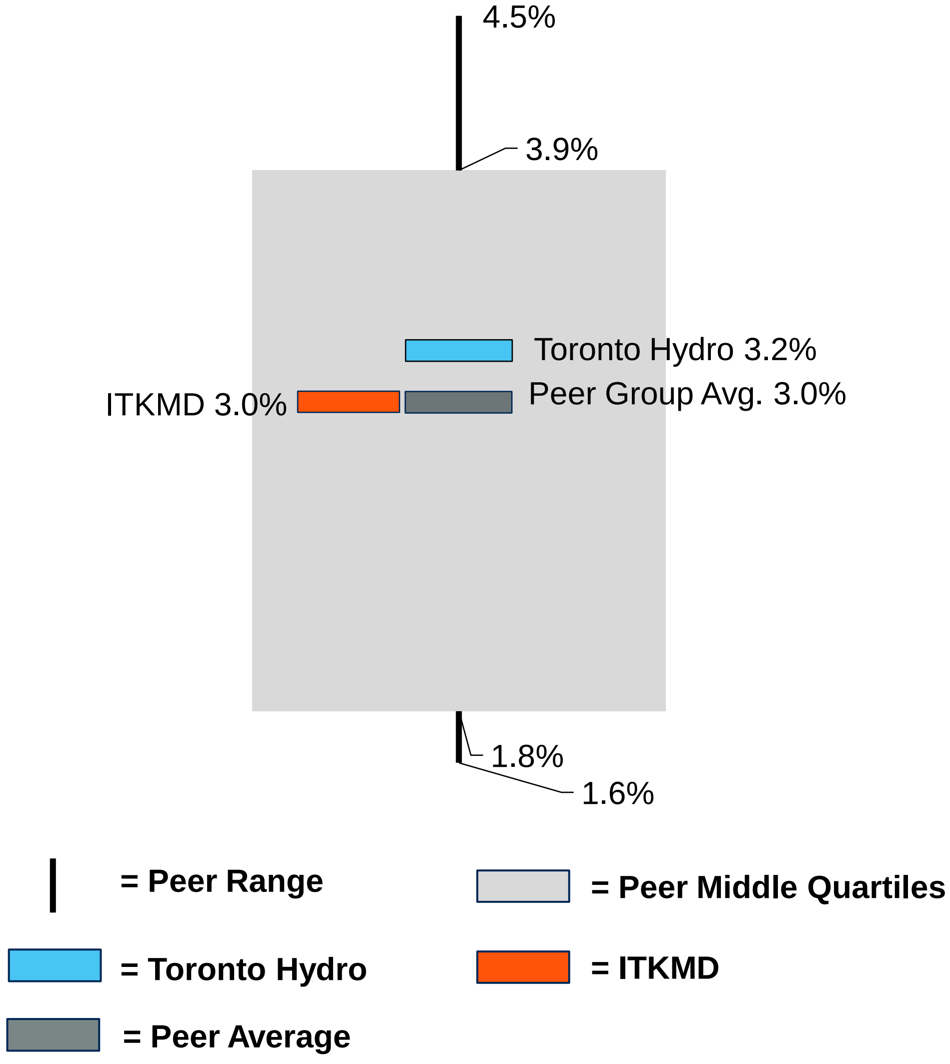
IT Spend as a Percentage of Revenue



Observations

- TH's 2022 IT Spending is a % of Revenue was 3.2% compared to an average of 3.0% for the peer group. This represents a spend level that is very similar to the peer group and ITKMD for Utilities organizations.

Description	• IT spending as a percentage of revenue provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Revenue	**Toronto Hydro: $114,759,546 / $3,601,700,000**

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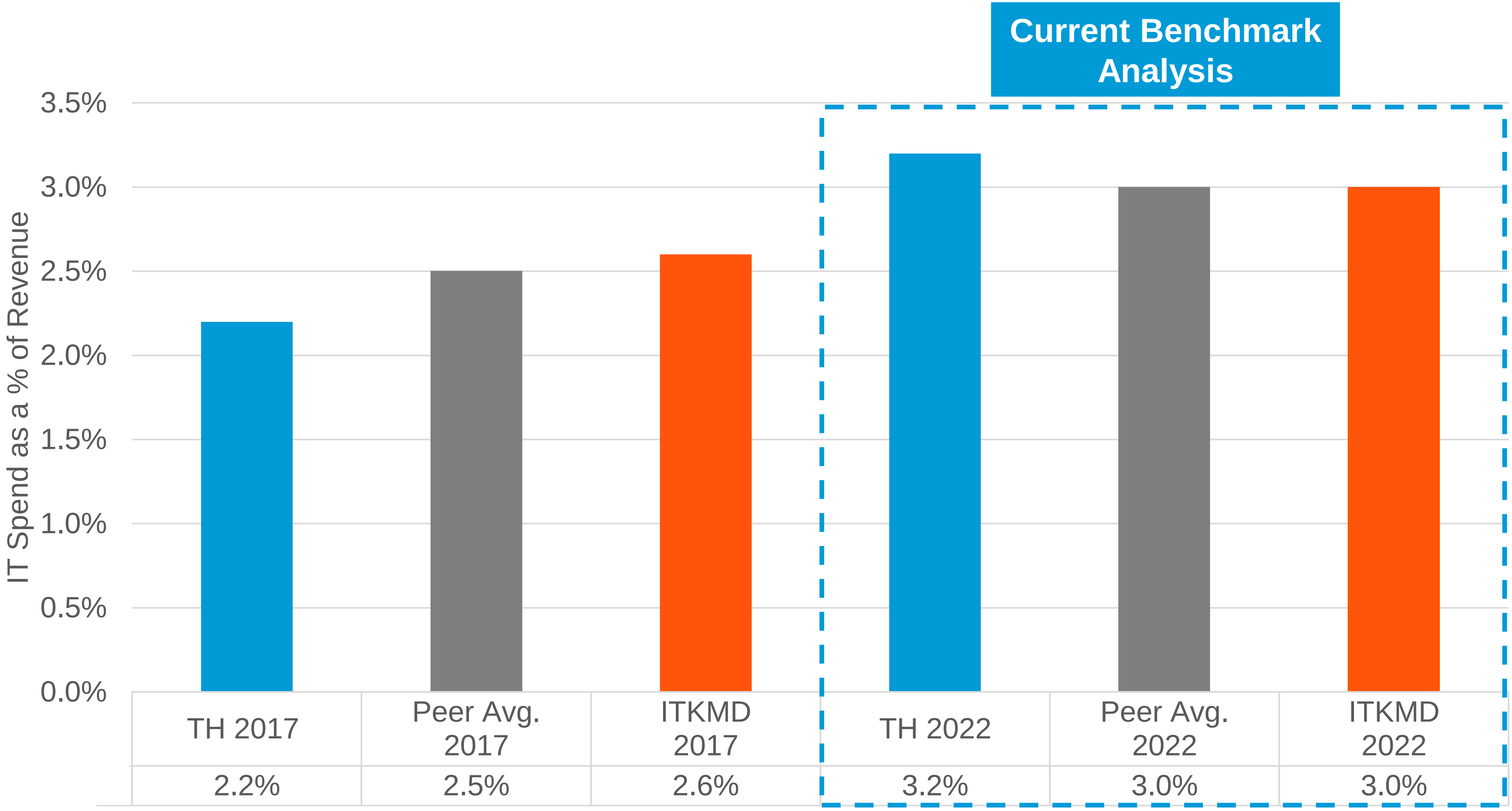
IT Spend as a Percentage of Revenue – Multi Year View



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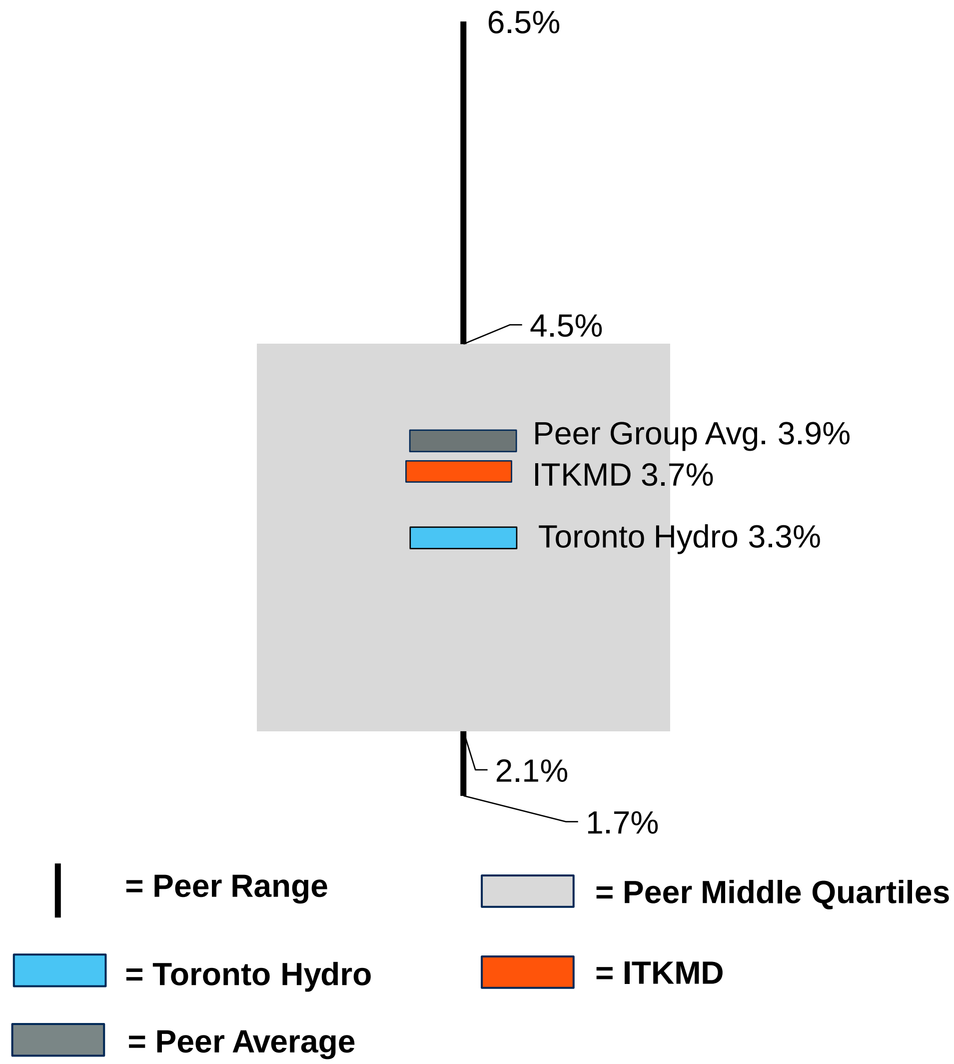
IT Spend as a Percentage of Operational Expense



Observations

- TH's 2022 IT Spending as a % of Operating Expense was 3.3% compared to an average of 3.9% for the peer group. This represents a spend level that is very similar to the peer group (15% less) and ITKMD for Utilities organizations (11% less).

Description	• IT spending as a percentage of operational expenses provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Operational Expense	**Toronto Hydro: $114,759,546 / $3,348,600,000**

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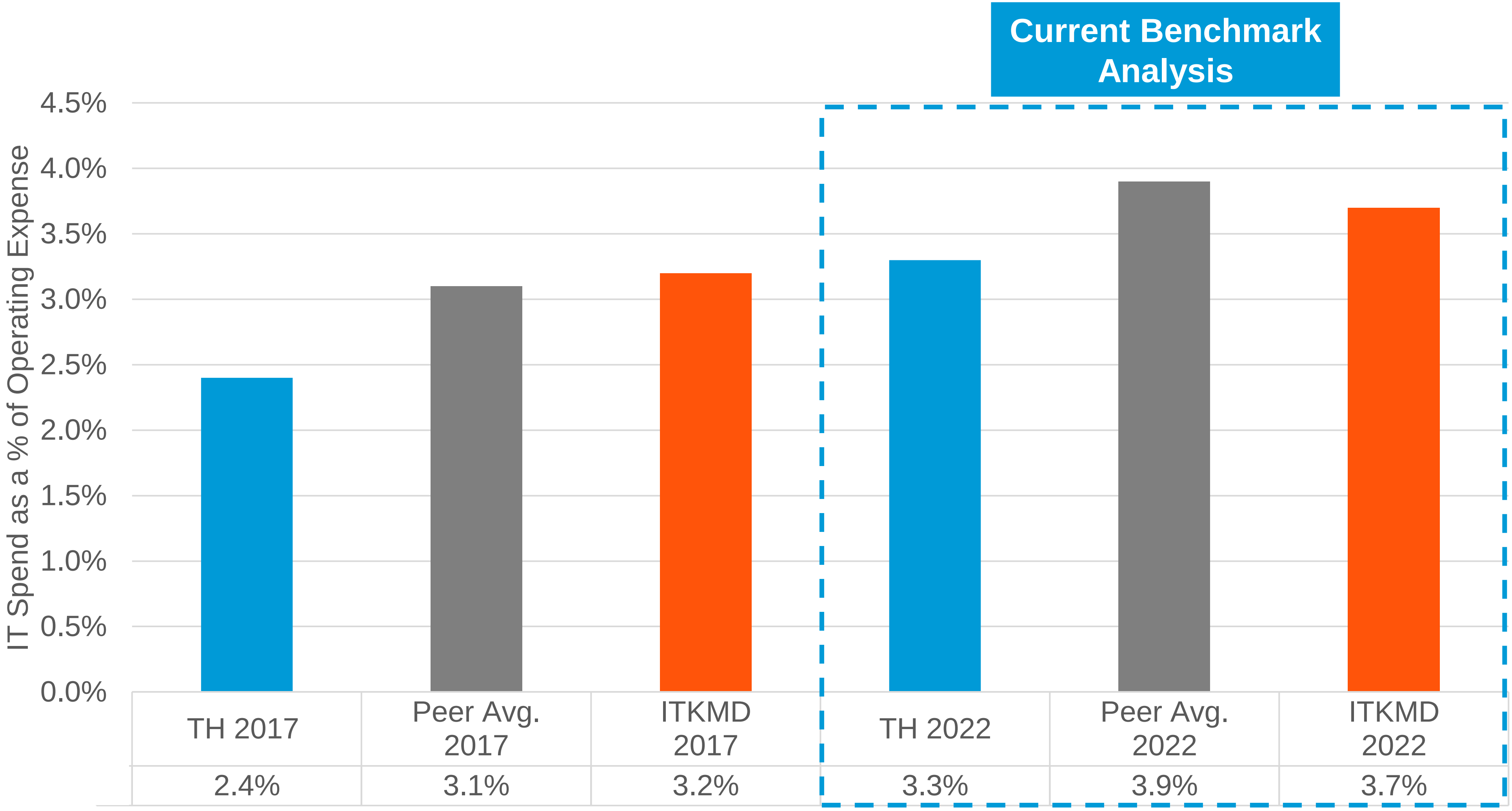
IT Spend as a Percentage of Operating Expense – Multi Year View



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Employees versus Users at Toronto Hydro

- Gartner typically collects the number of employees for an IT Enterprise Benchmark and bases two standard metrics on employee count: IT Spending per Employee and IT FTEs as a Percentage of Employees.
    - Many of the IT departments Gartner works with, and has in our peer benchmark database, typically do not know the number of contractor labour or level of outsourcing in the lines of business, and Gartner does not normally collect a number of users.
- As with other measures comparing IT spending to business measures, these two metrics can be influenced by both the numerator and denominator.
- For TH, these two metrics appear to be skewed compared to the peer group when based on the employee count.
- As a test of this assumption, Gartner focused the analysis using TH number of Users rather than Employees and compared results.
- While metrics based on Employees are 116% to 133% more than the peer group, the results based on Users are between 29% and 35% less than the peer group.
    - The metrics based on Users are in line with the other metrics (IT Spending as a Percentage of Revenue and Operational Expense), supporting the assumption that it is TH employee count, not IT spending or staffing that drives the results on slides 24 and 26.

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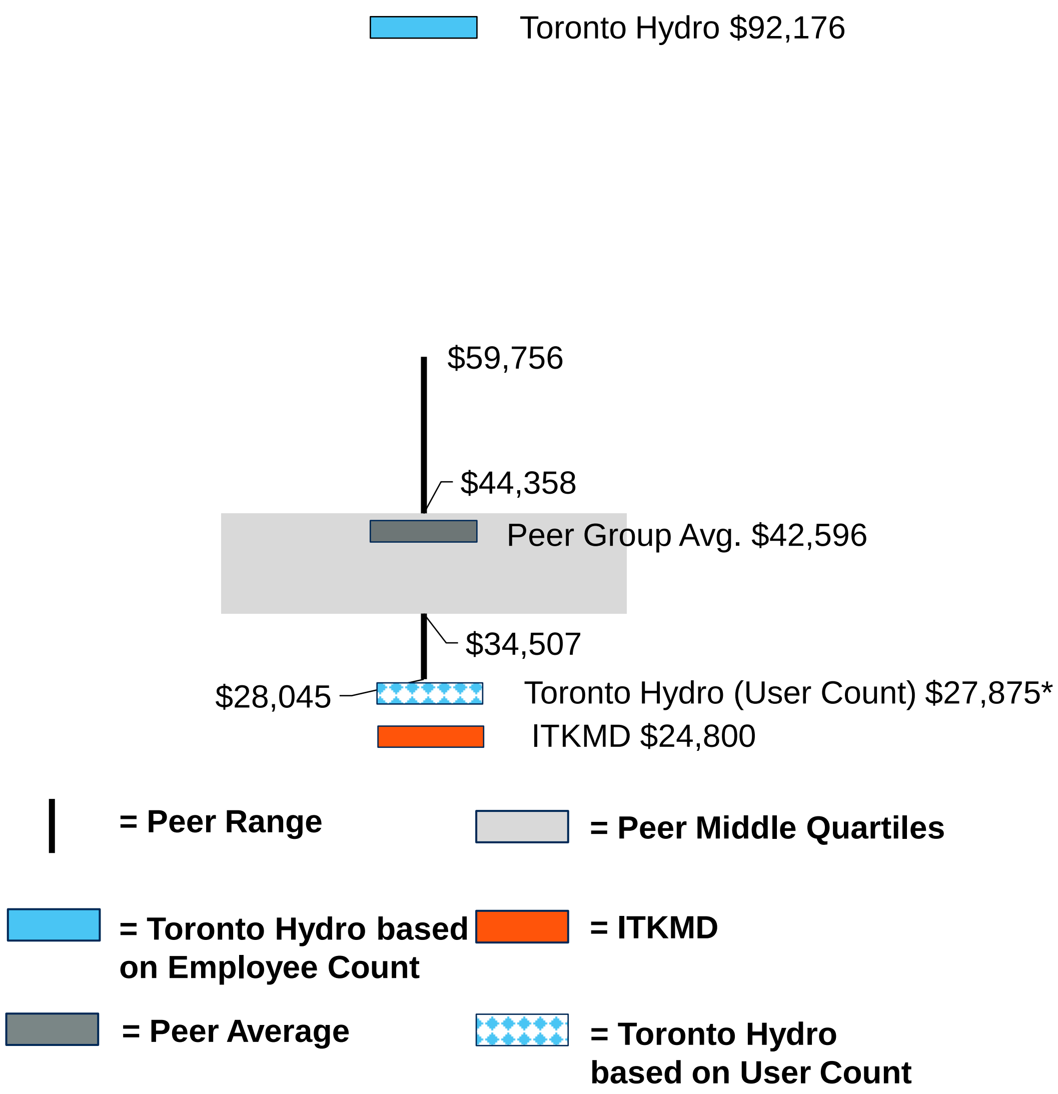
IT Spend per Employee



Observations

- IT Spend per User for TH is 35% less than the peer group average of $42,596, and similar with the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT spend per User metric rather than IT spend per Employee

Description	• IT spending per employee provides insight into the amount of technology support an organization's workforce receives. • High spending can imply higher levels of automation and/or higher investment in IT in general. Low spending levels can be related to higher overall staffing levels and or lower IT investment than peers. • Large variations within industry groups can represent different business models for service or product delivery.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses and includes project spending. Organization Employees includes staff, exclusive of Contractors.	
Calculation	IT Spending / Organization Employees	**Toronto Hydro: $114,759,546 / 1,245**

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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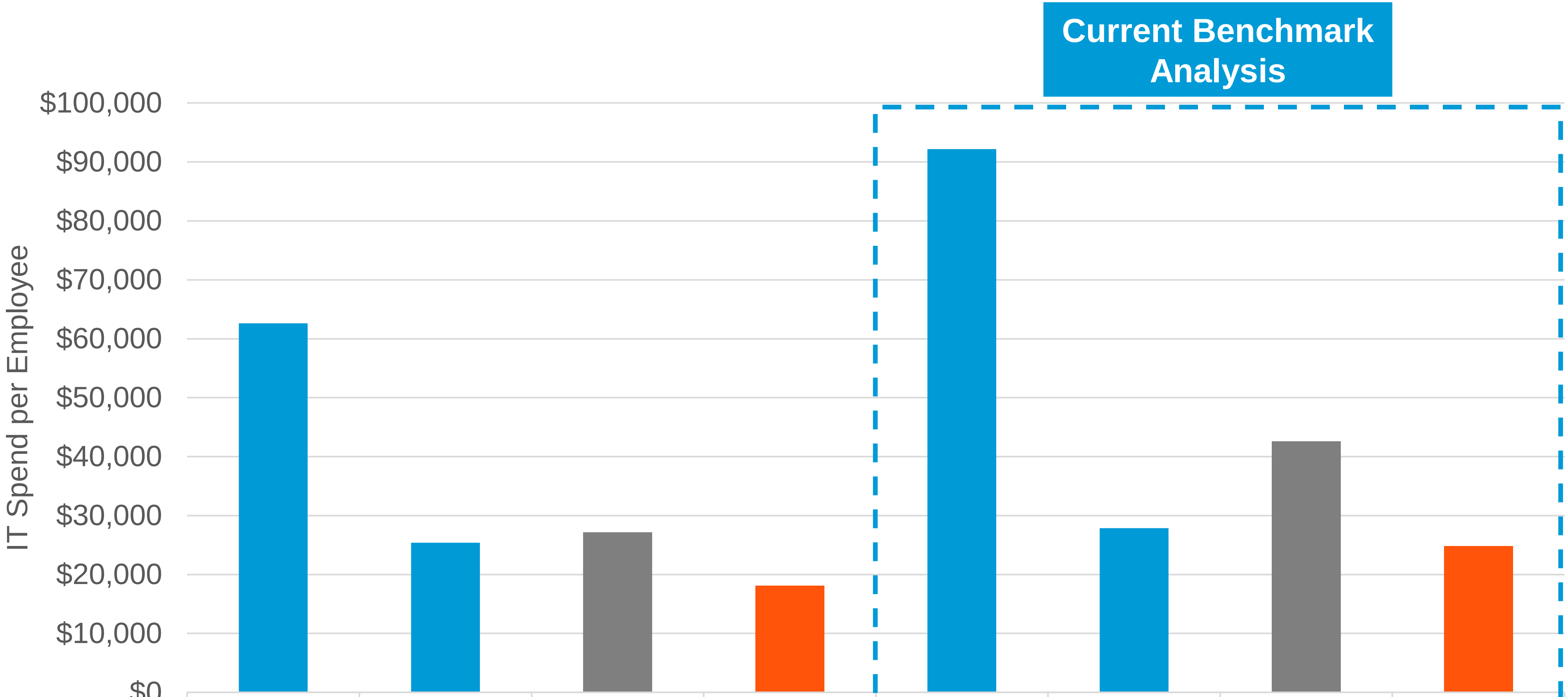
IT Spend per Employee – Multi Year View



TH 2017	TH 2017 Users*	Peer Avg. 2017	ITKMD 2017	TH 2022	TH 2022 Users*	Peer Avg. 2022	ITKMD 2022
$62,635	$25,383	$27,135	$18,100	$92,176	$27,875	$42,596	$24,800

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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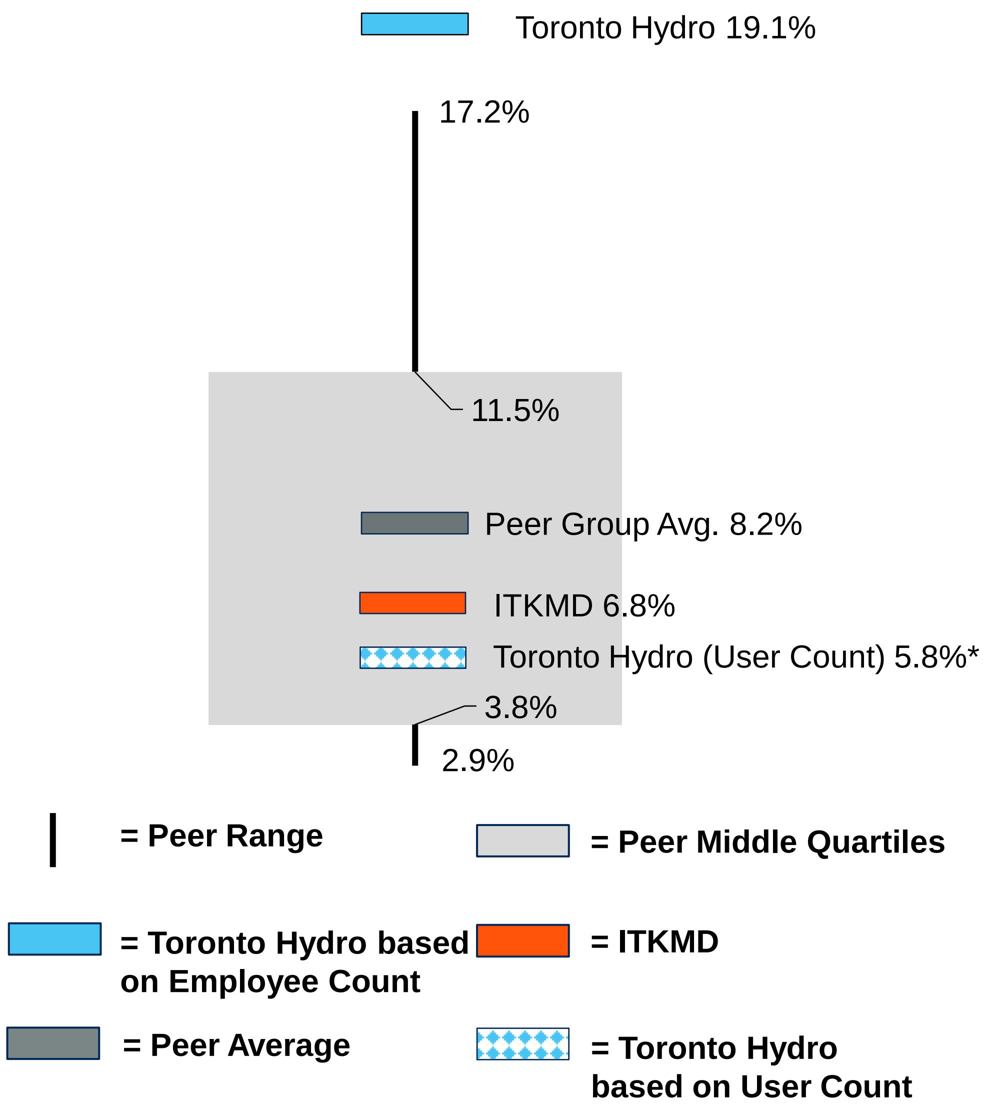
IT FTEs as a Percentage of Total Employees



Observations

- IT FTEs as a % of Total Users is 29% below the peer group average and 15% below the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT FTEs as a % of Users metric rather than IT FTEs as a % of Employees*

Description	• The percentage of IT FTEs in the organization compared to the total number of employees is a key measure of how critical IT support is to the business. This measure can be heavily influenced, however, by the level of outsourcing an organization may have. • Organizations with high levels of manageability and automation should require fewer operations staff. Manual processes and lack of standards will increase the number of IT FTEs needed.	
Definition	IT FTEs includes in-house and contractor FTEs, does not include managed services adjusted FTEs. Organization Employees includes employees, exclusive on Contractors.	
Calculation	IT FTEs / Organization Employees	**Toronto Hydro: 238 / 1,245**

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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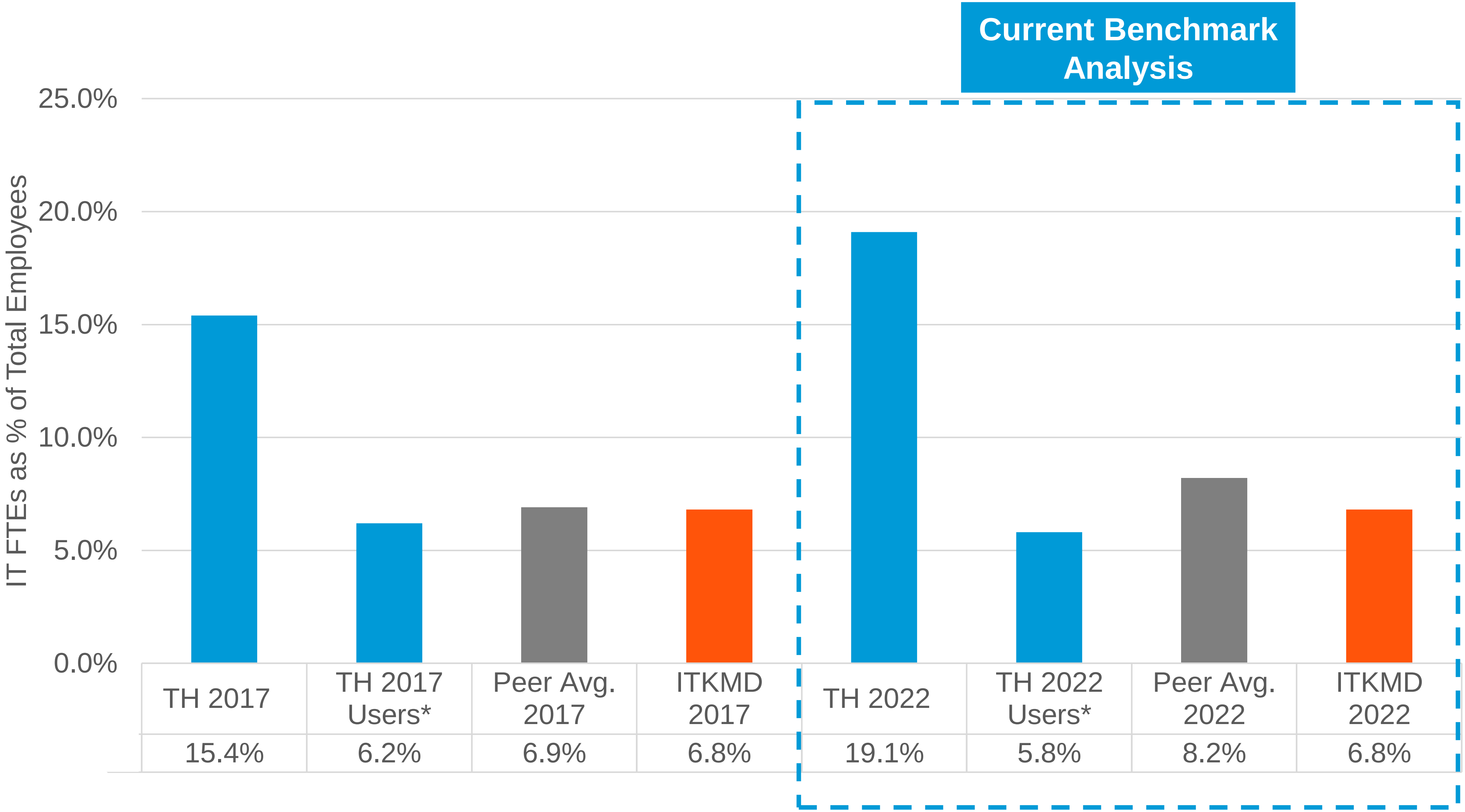
IT FTEs as Percentage of Total Employees – Multi Year View



* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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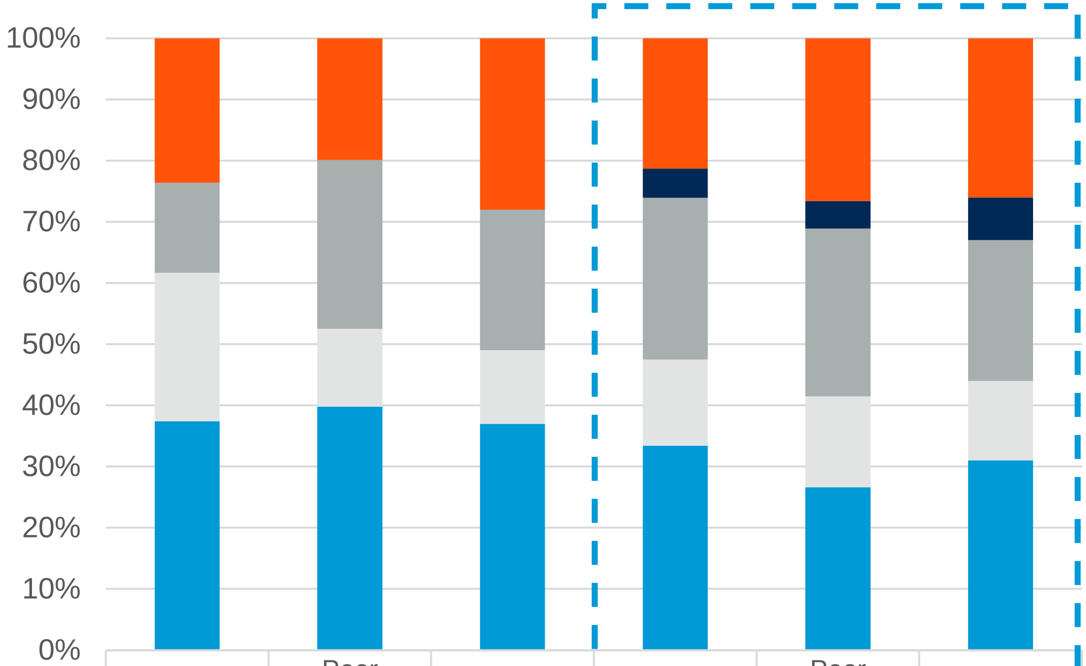
IT Spend Distribution by Cost Category

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
External Services	23.6%	19.9%	28.0%	21.3%	26.6%	26.0%
Software (SaaS)				4.8%	4.5%	7.0%
Software (On-Prem)*	14.7%	27.6%	23.0%	26.4%	27.4%	23.0%
Hardware	24.3%	12.7%	12.0%	14.1%	14.9%	13.0%
Personnel	37.4%	39.8%	37.0%	33.4%	26.6%	31.0%

Observations

- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).
- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.2% of IT spending in 2022) is virtually the same as the peer group.

Description	• This measure can be helpful in adding context to the IT investment strategy from a sourcing perspective, in terms of accounting-based resources that may be insourced versus services delivered by a third party. • As an organization increases or decreases the level of outsourced services, it may find an inverse effect in its associated personnel, hardware and/or software expenditures, depending on the scope of services retained and on requirements.
Definition	Allocated IT Spending among the different cost categories

* In 2017 Gartner benchmarking did not separate Software as a Service (SaaS) from On-Premises Software. 2017 “Software (On-Prem)” includes all software spending.

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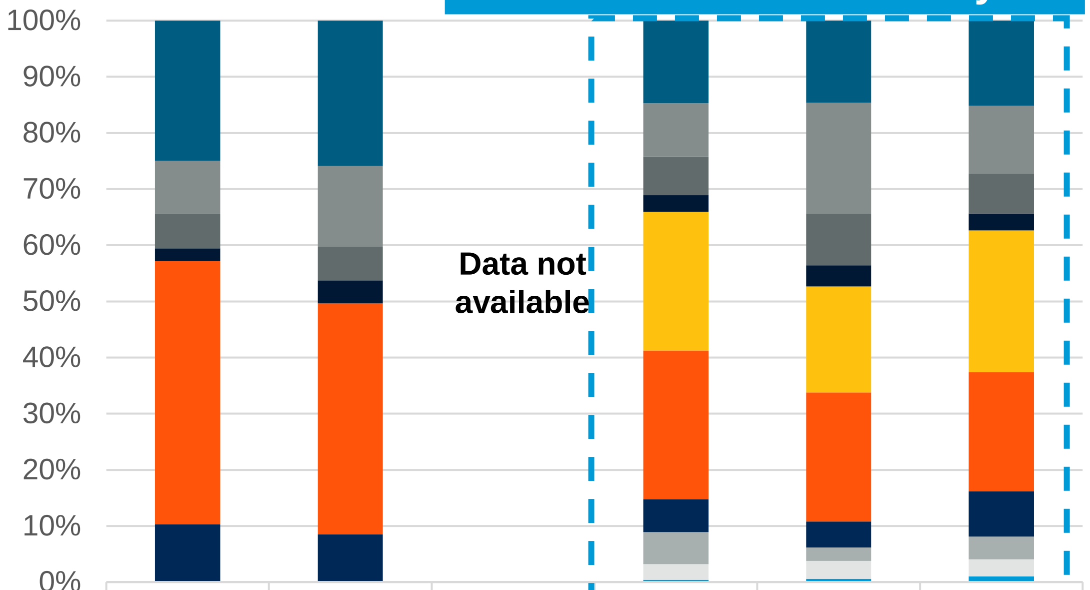
IT Spend Distribution by IT Functional Area

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	25.0%	25.9%		14.7%	14.6%	15%
Network	9.5%	14.4%		9.5%	19.8%	12%
Workplace Services	6.1%	6.0%		6.9%	9.2%	7%
IT Service Desk	2.3%	4.1%		3.0%	3.8%	3%
Application Development				24.7%	18.9%	25%
Application Support*	46.9%	41.2%		26.5%	23.0%	21%
Governance & Service Management**	10.3%	8.5%		5.9%	4.6%	8%
IT Security				5.7%	2.4%	4%
IT Ops. Mgmt				2.8%	3.2%	3%
Ser. Con't / DR				0.4%	0.6%	1%

Observations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million.
- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, as compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.

Description	• This information is often leveraged in tandem with IT resource planning exercises, wherein resource allocations can be viewed in terms of IT infrastructure versus applications versus IT overhead. • While this measure is helpful in identifying relative volumes of IT resource consumption by IT functional area, as compared to Peers, it does not aid in identifying whether resources are being leveraged in a cost-effective or productive manner.
Definition	Allocated IT Spending among the different functional areas

* In 2017 application development and application support were not separated
** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

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IT FTEs Distribution by IT Functional Area

Current Benchmark Analysis

	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	19.0%	10.9%		15.1%	4.5%	10%
Network	7.7%	9.9%		6.7%	6.0%	9%
Workplace Services	8.7%	9.5%		6.3%	4.4%	6%
IT Service Desk	3.1%	7.6%		1.7%	8.0%	7%
Application Development				28.6%	27.5%	24%
Application Support*	47.2%	49.2%		18.5%	19.1%	20%
Governance & Service Management**	14.5%	12.7%		14.7%	19.9%	14%
IT Security				6.7%	4.5%	4%
IT Ops. Mgmt				1.3%	5.5%	4%
Ser. Con't / DR				0.4%	0.5%	1%

Observations

- IT FTE distribution for TH is similar to the peer group with the exception of Enterprise Computing (235% more), ITSD (78% less) and IT Operations Management (76% less)
- TH leverages on-site data centers supported by IT FTEs, no cloud infrastructure is used

Description	• By viewing human resources (IT FTEs) within the context of the total portfolio, organizations are able to identify which environment is the most labour- intensive as a % of the IT labour pool. Typically, application activities (development and support) demand the most resources from both cost and staffing perspectives. The degree to which an organization outsources should be considered alongside such staffing metrics.
Definition	Distributes In House and Contractor IT FTEs among the different functional areas

* In 2017 application development and application support were not separated

** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

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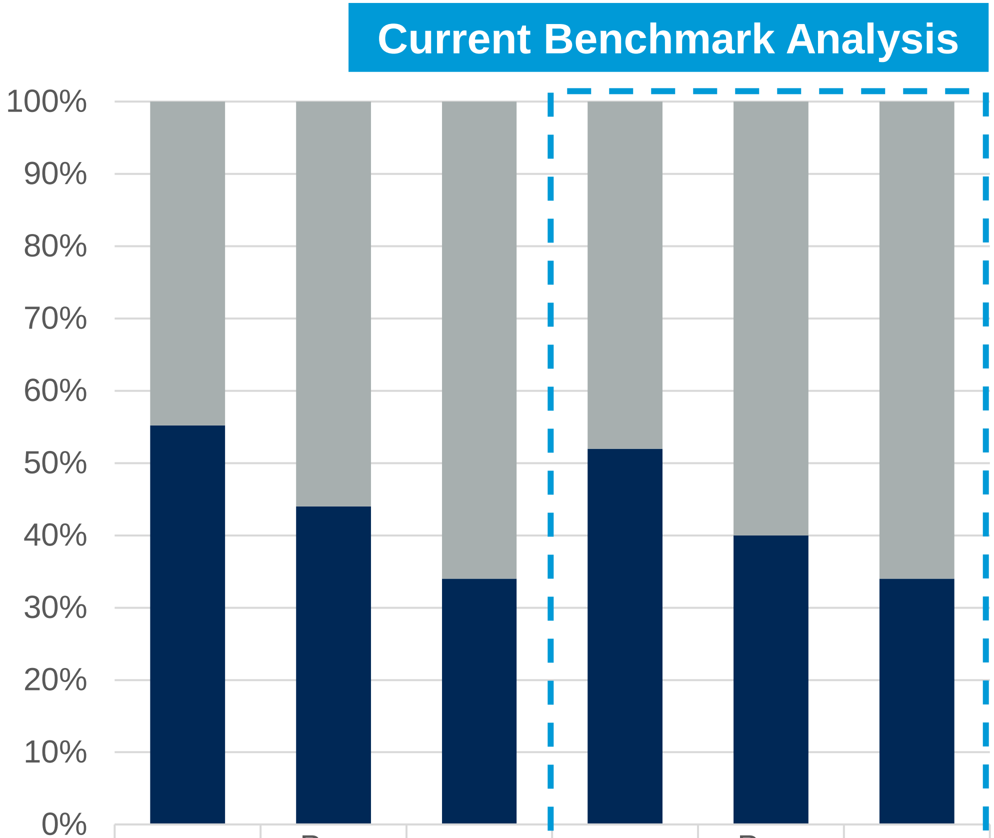
IT Spend Distribution – Operations vs. Capital



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Operational	45%	56%	66%	48%	60%	66%
Capital	55%	44%	34%	52%	40%	34%

Observations

- TH allocated more of its IT spending to capital (52%) than the peer group average of 40%
- Applications and Infrastructure are increasingly cloud-based, creating an escalating shift away from more traditional capital-based models to operational funding.
- There can be unanticipated or overlooked operating budget increases as a result of Software as a Service (SaaS) and Infrastructure as a Service (IaaS) contracts. The resultant shift from capital expenditure (CapEx) to operating expenditure (OpEx) can cause budgetary and cost management pressures.

Description	• IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year. • Organizations with a higher capital spending may… ○ Be investing heavily in strategic IT infrastructure ○ Have reached a planned point of investment in their infrastructure lifecycle ○ Not have been managing asset investments well (i.e., “catching up”) ○ Simply have a more aggressive capitalization policy • The break out of Run, Grow, Transform spending that follows may provide more insight
Definition	Distribution of IT Operational spending versus Capital spending

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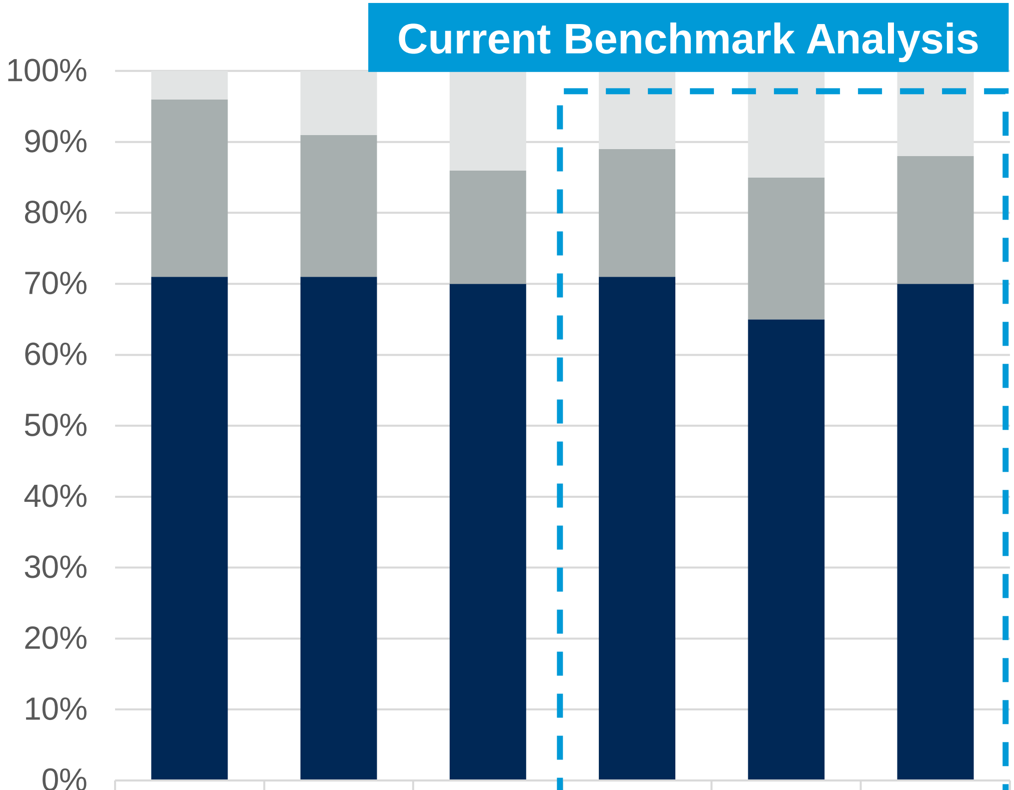
IT Spend Distribution by Run, Grow and Transform



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Transform	4%	9%	14%	11%	15%	12%
Grow	25%	20%	16%	18%	20%	18%
Run	71%	71%	70%	71%	65%	70%

Observations

- In 2022, Toronto Hydro allocated 29% of IT Spending to "change the business" activities (18% Grow and 11% Transform), similar to the peer group average of 35% and the 2017 level of 29%
- However, TH allocated more to the "Transform" category in 2022 (11%) compared with 2017 (4%). This is the result of digital transformation investments.

Description	• The distribution of IT spending provides a view of the investment profile in business terms (how IT will enable the business to grow or transform revenue, operating income and/or profit margins)
Definition	Allocation of IT Spending by Run, Grow and Transform, where: • Run: Essential (and generally non-differentiated) business processes. • Grow: Improvements in operations and performance, within current business models • Transform: new services and new operating models

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04
IT Maturity Assessment Analysis

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Toronto Hydro’s IT Assessment is focused on process maturity and spending & staffing as compared to peer organizations

Section 4.0 Focus

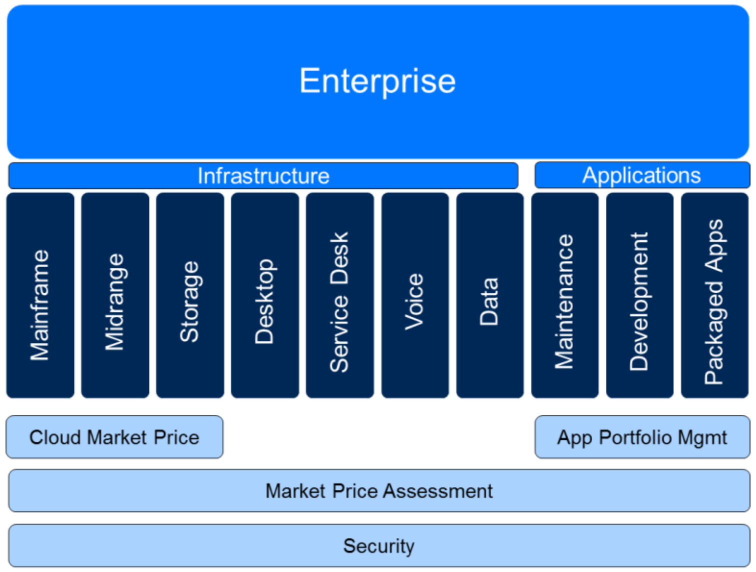
PROCESS MATURITY

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

SPENDING AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

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IT Maturity Assessment Methodology Overview

Gartner used its industry-leading IT maturity models (IT Score) to evaluate Toronto Hydro’s IT capabilities across the in-scope domains relative to peers. IT Score provides insights on maturity and importance to gain perspective on the highest priority activities to improve.

Maturity

- Measured on a scale ranging from 1 (low) to 5 (high), maturity measures how advanced an activity is relative to Gartner’s best-practice research.

Importance

- Measured on a scale ranging from 1 (unimportant) to 5 (critical) based on participants’ inputs, importance measures how important each activity is to the overall effectiveness in meeting objectives.

Prioritization

- Activity priority index (API) identifies the activities that should be prioritized for improving maturity. It is defined as the average gap between importance and maturity and is computed for each activity and weighted by its average importance.

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Analysis Notes

- Toronto Hydro completed Gartner's IT Score surveys to baseline current maturity and importance levels
- Results were reviewed and calibrated across IT domains in working sessions with Gartner and the Toronto Hydro project team

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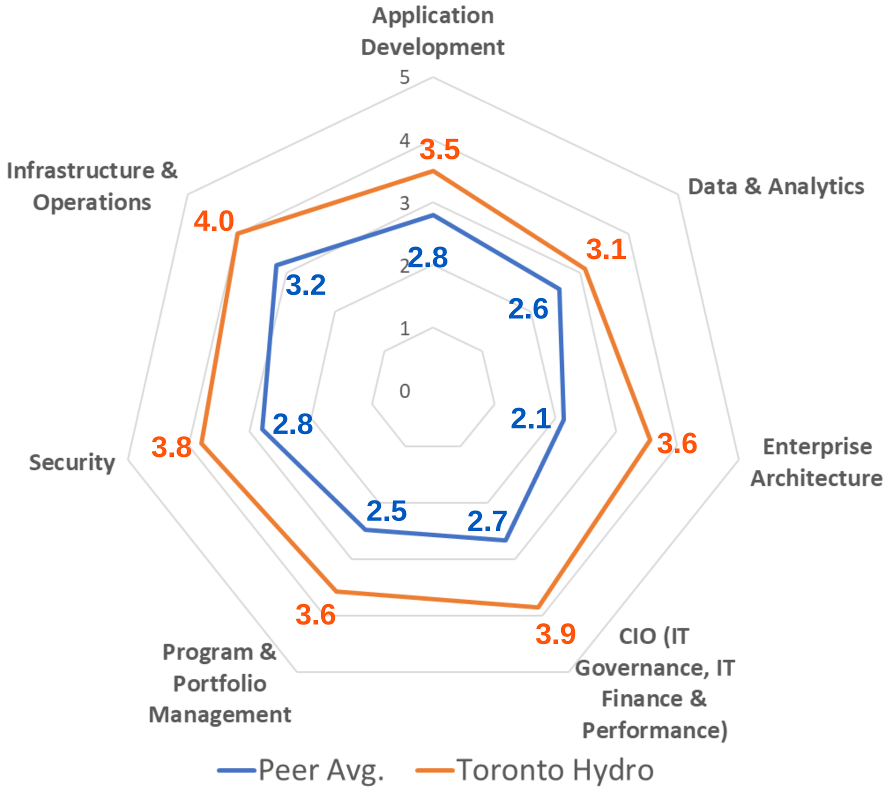
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

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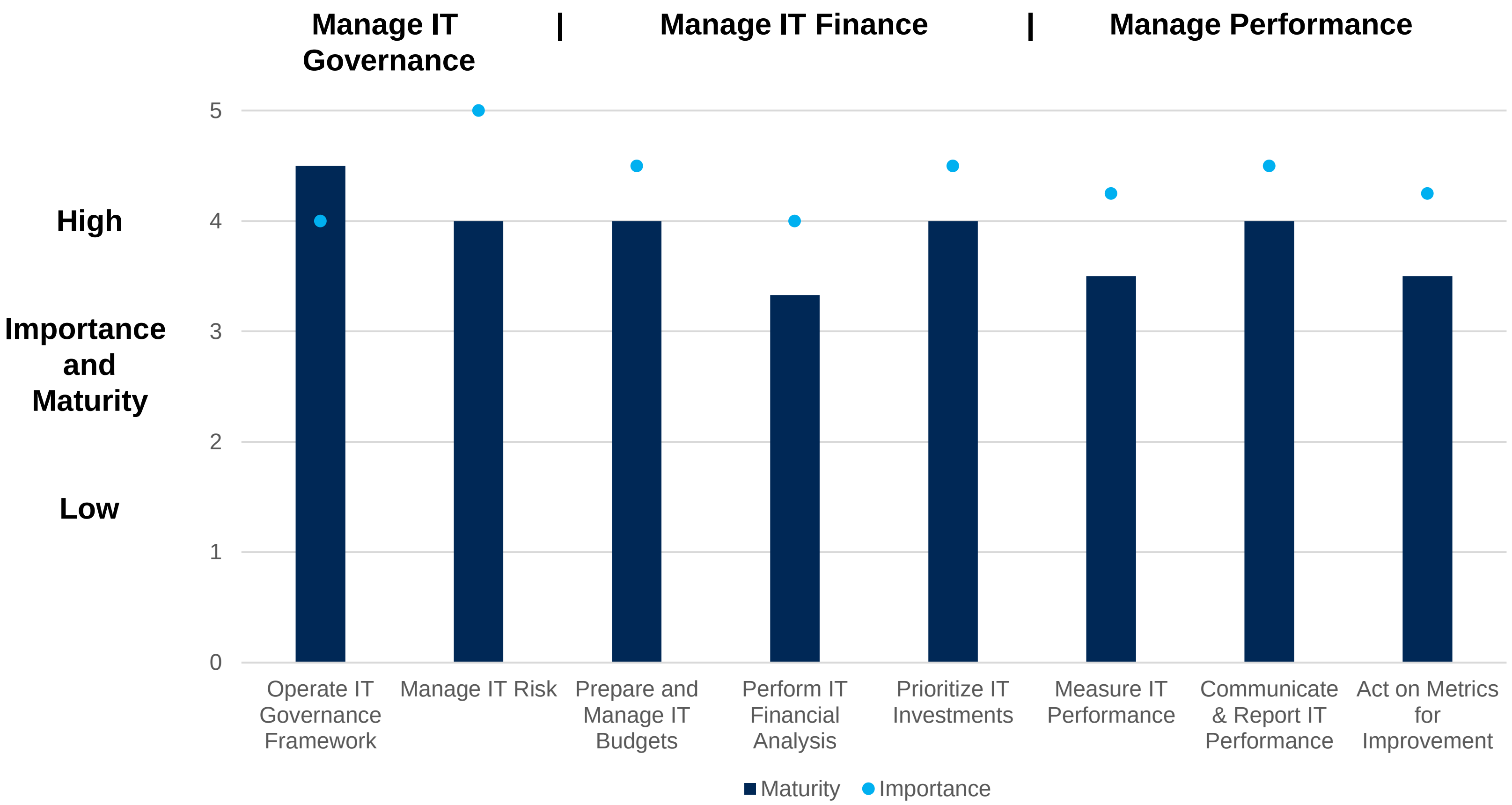
Chief Information Officer (CIO)
How Do Maturity and Importance Compare?



Lowest Maturity
- Perform IT Financial Analysis
- Measure IT Performance
- Act on Metrics for Improvement

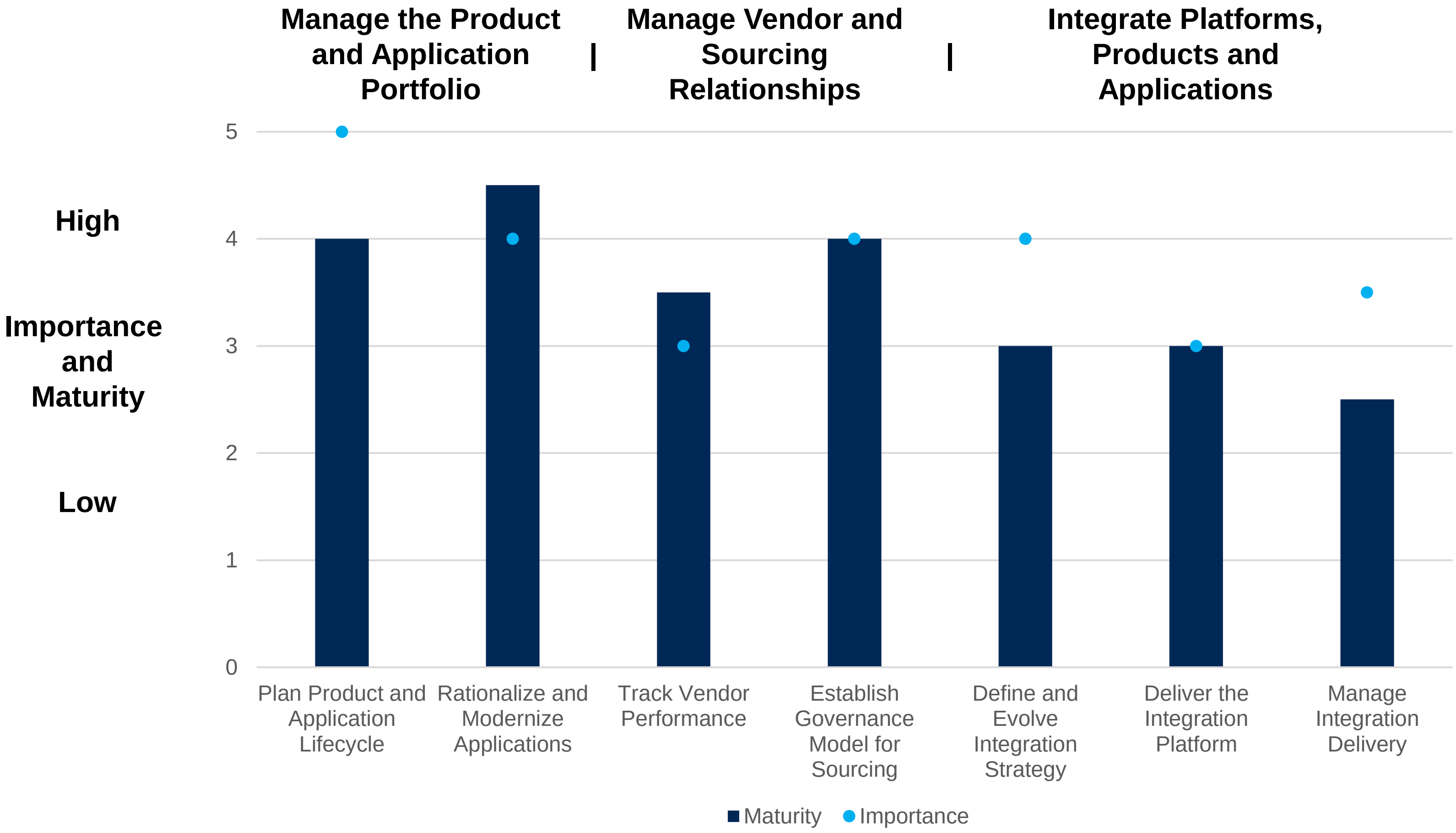
Highest Importance
- Manage IT Risk
- Prepare and Manage IT Budgets
- Prioritize IT Investments

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Chief Information Officer (CIO) Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage IT Governance	Operate IT Governance Framework	4.5	4: the IT governance framework is adaptive and enables the agility of I&T decision making across the enterprise 5: the IT governance framework enabled autonomous I&T decision making across the ecosystem, digital platform and enterprise
	Manage IT Risk	4.0	4: an IT risk discipline considers both risk and reward on I&T decision making from a business and perspective. The business carried formal accountability for IT risk as part of its enterprise risk management.
Manage IT Finance	Prepare & Manage IT Budgets	4.0	4: I&T budgets are aggregated across the enterprise and support products. Budgets are compared with actual performance and revised at least quarterly to accommodate changing business priorities
	Perform IT Financial Analysis	3.3	3: IT performs cost analysis on all I&T across the enterprise as part of the formal monthly or quarterly IT management process. I&T spending by service is well understood by business unit and includes measurement and reporting against business-based SLAs. Spending optimization initiatives include joint business and IT savings 4: IT streamlines and automates financial analysis, which emphasizes growth and competitive differentiation. IT performs financial analysis at the I&T product level in terms that the business understands. IT and business leaders follow an adaptive, iterative, organization-wide value-optimization process
	Prioritize IT Investments	4.0	4: the CIO and senior enterprise executives prioritize all investments at the enterprise level at least quarterly to achieve innovation and differentiation. Business cases for I&T requests contain business outcomes and use specific value and risk methods.
Manage Performance	Measure IT Performance	3.5	3: IT performance is measured through business-value-based SLAs that correlate to business outcomes and employee experience. 4: IT and business performance is fused and jointly measured through strategic business benefits realization and external customer / citizen satisfaction.
	Communicate & Report IT Performance	4.0	4: IT proactively communicates to senior business executives how I&T across the enterprise is leveraged for business capabilities and competitive differentiation, which influences strategy and innovation investments
	Act on Metrics for Improvement	3.5	3: The IT organization has defined a process-to-service map that identified IT processes' relationship to IT service outcomes, and remediation efforts result in improvements in end-to-end service quality. 4: Empowered, multidisciplinary business/IT product teams prioritize their own continuous improvement objectives for products, business processes, business outcome and external customer / citizen experience

Applications
How Do Maturity and Importance Compare?



Lowest Maturity

- Manage Integration Delivery
- Deliver the Integration Platform
- Define and Evolve Integration Strategy

Highest Importance

- Plan Product and Application Lifecycle
- Rationalize and Modernize Applications
- Establish Governance Model for Sourcing
- Define and Evolve Integration Strategy

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Applications
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage the Product & Application Portfolio	Plan Product & Application Lifecycle	4.0	4: the product and application roadmaps include opportunities of emerging technology for the next 2-5 years
	Rationalize & Modernize Applications	4.5	4: rationalization and modernization initiatives are integral part of business transformations 5: rationalization and modernization of products and applications is continuous and a separate discipline with dedicated resourced and ongoing funding
Manage Vendor & Sourcing Relationships	Track Vendor Performance	3.5	3: a role of vendor manager is established to track groups of vendors and associated records. Formal spreadsheets (scorecards) are put in place to ensure consistency of tracking across vendors 4: performance of all vendors is institutionalized, and organization uses it to derive insight to assist with vendor selection. Internal customers are polled to obtain full measure of overall customer satisfaction for each vendor
	Establish Governance Model for Sourcing	4.0	4: vendor relationships are managed by a team that has representation from all business sectors to ensure cross-organization representation
Integrate Platforms, Products & Applications	Define and Evolve Integration Strategy	3.0	3: an integration strategy team is established to provide integration delivery services to the applications teams. A formal centrally managed sourcing strategy is available
	Deliver the Integration Platform	3.0	3: one or more strategic integration tool has been selected, recommended and centrally supported. Integration solutions are implemented on the strategic tools by consistently adopting centrally defined common patterns and guidelines
	Manage Integration Delivery	2.5	2: application delivery teams autonomously address integration issues, optionally using a set of approved products that are supported by an integration platform team 3: an integration strategy team is in charge of delivering, on demand, integration solutions and/or strategic tools to support the applications delivery teams

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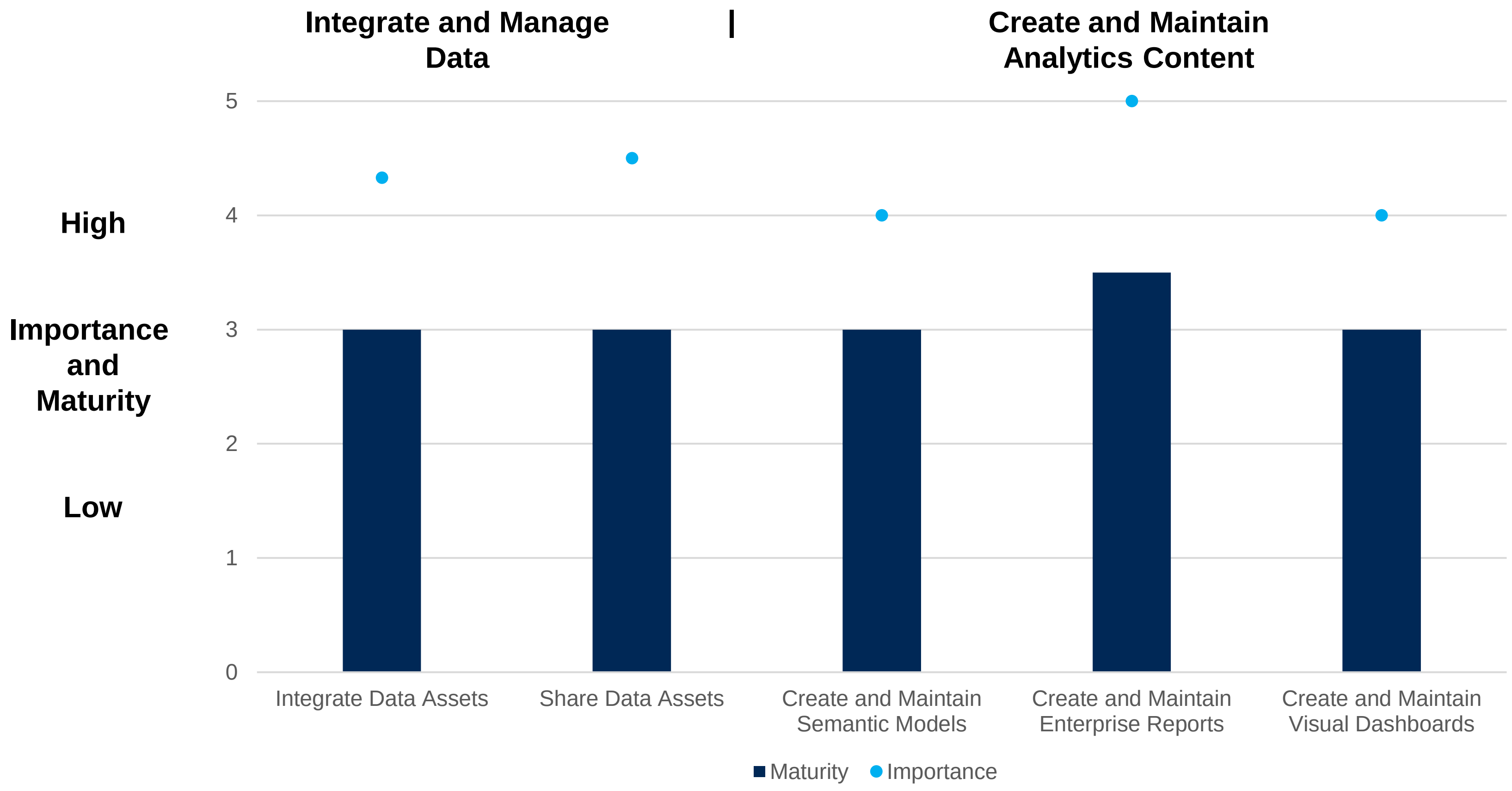
Data & Analytics
How Do Maturity and Importance Compare?



Lowest Maturity
- Integrate Data Assets
- Share Data Assets
- Create and Maintain Enterprise Reports
- Create and Maintain Visual Dashoards

Highest Importance
- Create & Maintain Enterprise Reports
- Share Data Assets
- Integrate Data Assets

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Data & Analytics Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Integrate & Manage Data	Integrate Data Assets	3.0	3: data integration practices combine multiple styles of integration to adapt to changing demands within a single use case
	Share Data Assets	3.0	3: data semantics can be shared regionally and mapped over various sources and applications
Create & Maintain Analytics Content	Create & Maintain Semantic Models	3.0	3: semantic models are created by IT and business to facilitate reporting and analysis by clearly defining dimensional attributes and measures
	Create & Maintain Enterprise Reports	3.5	3: there is a consistent process to develop interactive reports. Reports can also be distributed via e-mail 4: consumers of reports access reports using search as opposed to more complicated hierarchical folders. Moreover, reports can be delivered to mobile devices.
	Create & Maintain Visual Dashboards	3.0	3: departments and business units are enables to build their own dashboards. Also, dashboards include geospatial and location intelligence capabilities

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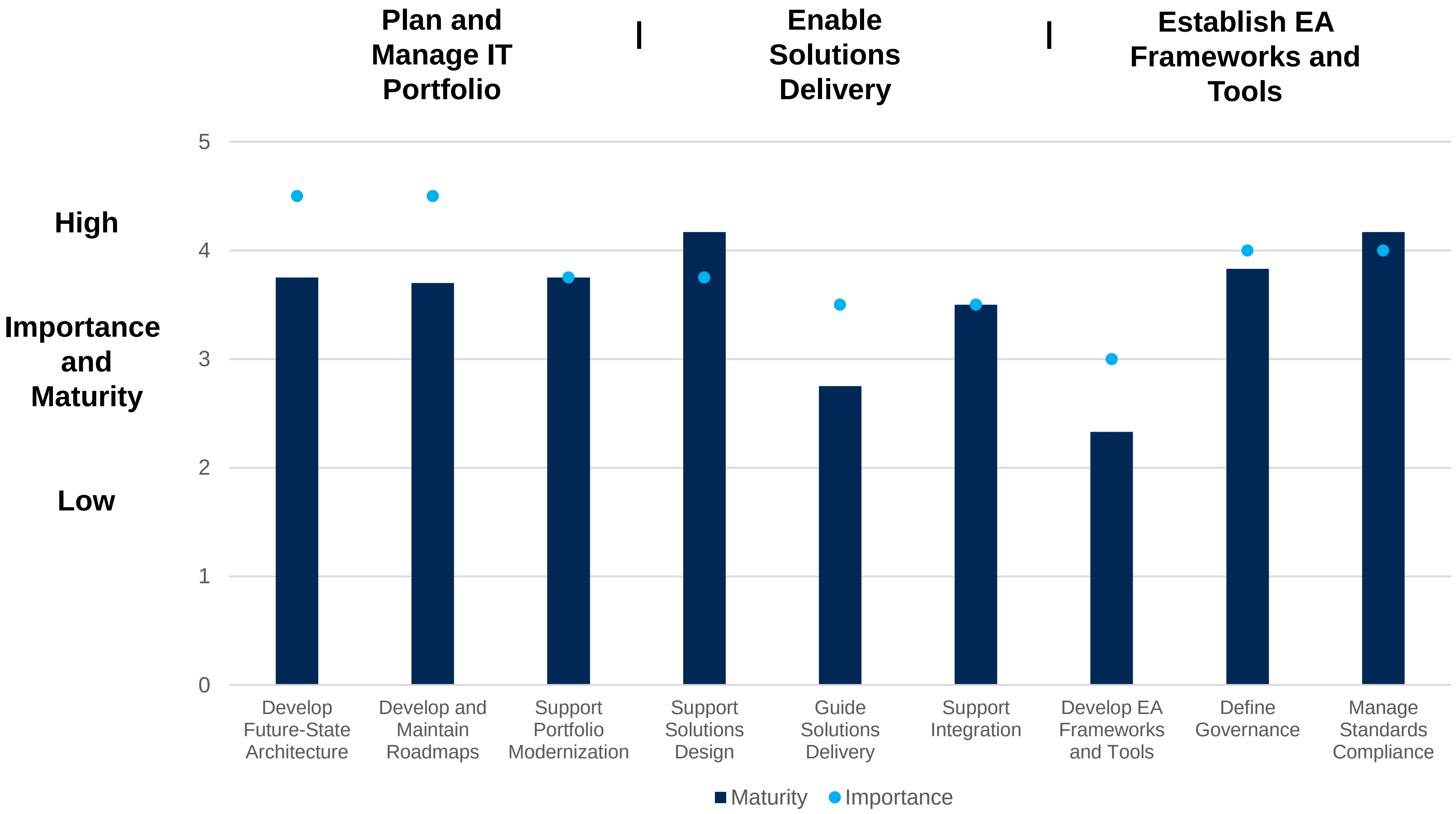
Enterprise Architecture & Technology Assessment
How Do Maturity and Importance Compare?



Lowest Maturity

- Develop EA Frameworks and Tools
- Guide Solutions Delivery

Highest Importance

- Develop Future State Architecture
- Develop and Maintain Roadmaps

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Enterprise Architecture & Technology Assessment (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Plan & Manage IT Portfolio	Develop Future-State Architecture	3.8	3: EA coordinates with stakeholders to create an enterprise future-state plan across technology domains and/or business areas 4: EA regularly recalibrates the future-state plan based on criticality of business capabilities and technical debt
	Develop & Maintain Roadmaps	3.8	3: EA applies a formal process to roadmap how IT initiatives support business capabilities, while tracking project ro product costs, benefits, risks and interdependencies 4: EA continuously reviews and refreshes roadmaps that reflect multiple time horizons and business scenarios designed to improve or maintain capability health
	Support Portfolio Modernization	3.8	3: EA has a comprehensive view across the technology stack and advises IT delivery teams on sunset or update decisions based on an analysis of costs and benefits and business needs 4: EA tracks how existing technologies support business capabilities and targeted outcomes and makes recommendations based on opportunity cost and impact on speed to value
Enable Solutions Delivery	Support Solutions Design	4.2	4: EA helps development teams apply a customer-centric lens to solutions design and supporting architectural decisions for improved usability
	Guide Solutions Delivery	2.8	2: EA engages with development teams across the delivery life cycle through a stage-gated process to review compliance with internal standards 3: EA provides packaged guidance to keep solutions development on track with targeted business outcomes and manage risk to business processes and operations
	Support Integration	3.5	3: EA manages reusable services (APIs) and defines standards to support ease of integration 4: EA regularly assesses integration standards for relevance and defines and curates reusable services that accelerate integration

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Enterprise Architecture & Technology Assessment (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Establish EA Frameworks & Tools	Develop EA Frameworks & Tools	2.3	2: EA develops use cases to demonstrate the value of tools and frameworks and to justify investment. Usage is prescriptive and in support of projects or products, focusing on gathering artifacts, documentation and modeling 3: ES assess tool and framework utility holistically to best support future and current-state architecture
	Define Governance	3.8	3: EA aligns the governance framework with IT strategy and includes business context and cross-functional perspectives in strategic review of technology standards 4: EA connects governance with enterprise digital strategy by means of a forum like a strategy review board and analyyzes exceptions to review and update standards
	Manage Standards Compliance	4.2	4: EA promotes guardrails by offering self-service tools, highlighting business benefits such as speed and innovation and accelerating remediation for granted exceptions

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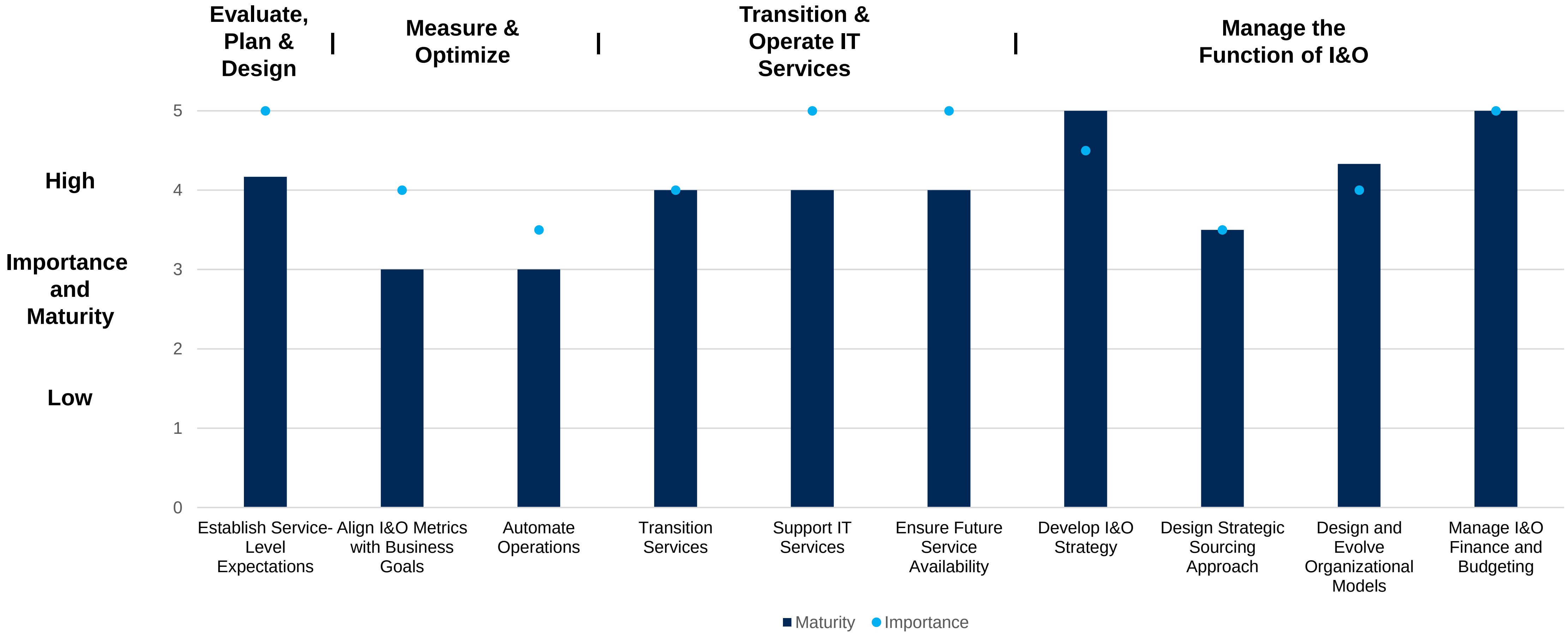
Infrastructure & Operations
How Do Maturity and Importance Compare?



Lowest Maturity
- Align I&O metrics with Business Goals
- Automate Operations
- Design Strategic Sourcing Approach

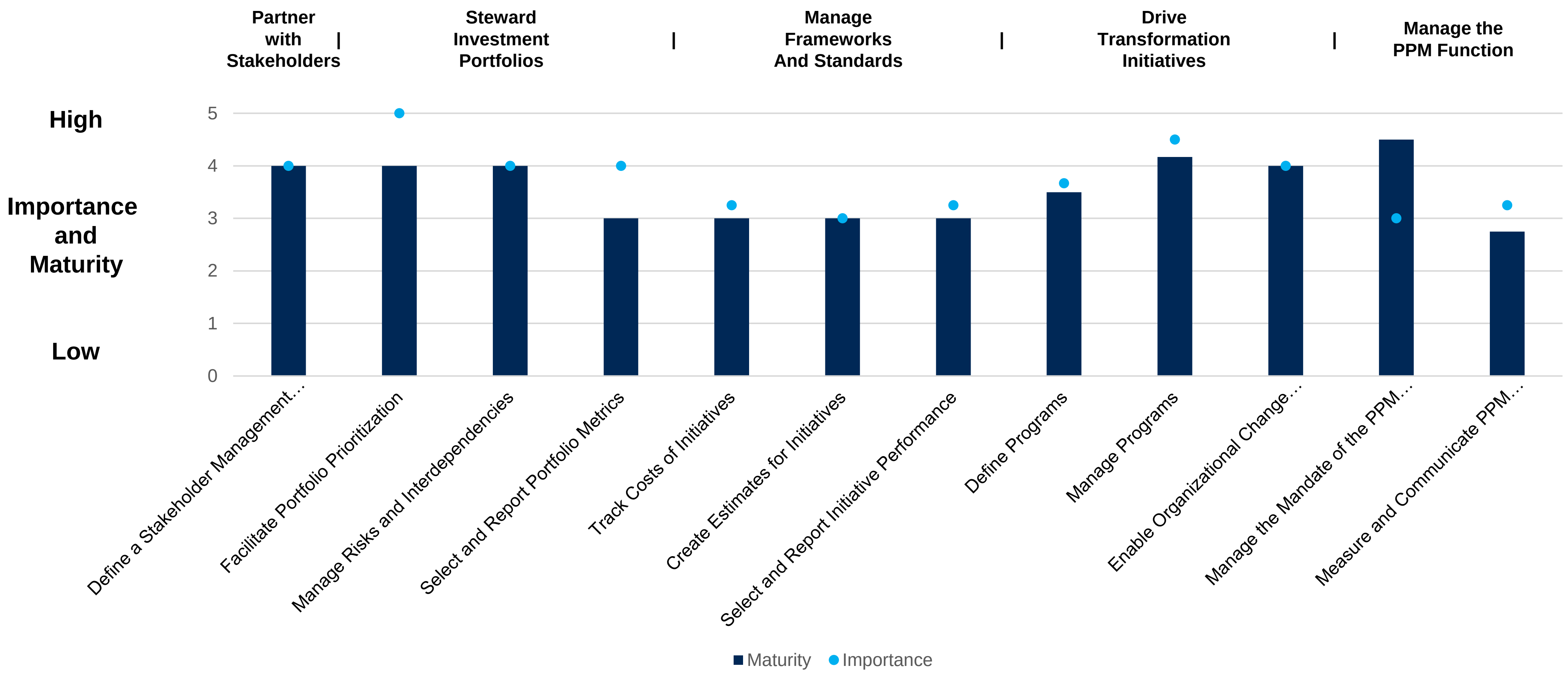
Highest Importance
- Establish Service-Level Expectations
- Support IT Services
- Ensure Future Service Availability
- Manage I&O Finance and Budgeting

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Infrastructure & Operations Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Evaluate, Plan & Design	Establish Service-Level Expectations	4.2	4: service levels that support critical business processes are defined and monitored in terms of their impact on user experience and critical workflows
Measure & Optimize	Align I&O Metrics with Business Goals	3.0	3: I&O is informed of business goals associated with applications and projects and generates periodic status and performance reports to the business in standard formats
	Automate Operations	3.0	3: automation is used to perform frequently repeated tasks, and staff has access to training on automation tools
Transition & Operate IT Services	Transition Services	4.0	4: a clear and robust service design process is in place, incorporating complete requirements. DevOps automation delivers business value quickly and effectively
	Support IT Services	4.0	4: I&O uses a service-based approach, with integrated ITSM and operational management tools. Key process owner, service owner and product owner roles are in place
	Ensure Future Service Availability	4.0	4: asset relationships are developed and stored in a CMDB; the estate is monitored at the service level; and measures are in place to manage the estate and deliver higher availability and stability
Manage the Function of I&O	Develop I&O Strategy	5.0	5: build strategies in collaboration with business partners, and follow agile methodology to respond quickly and adapt iteratively to enable changes in business priorities and strategies
	Design Strategic Sourcing Approach	3.5	3: base sourcing decisions on enterprise needs, cost optimization and categorized vendors. Determine solutions in collaboration with other IT teams 4: base sourcing decisions on fit-for-purpose analysis and identify solutions in collaboration with IT partners and input from business
	Design & Evolve Organizational Models	4.3	4: map out critical handoffs between teams and organize team members around service delivery 5: support cross-functional teams)such as DevOps teams or automation centers of excellence) and organize around IT products and/or business goals
	Manage I&O Finance & Budgeting	5.0	5: explain to business leaders how financial decisions positively affect business objectives and ensure transparency by engaging stakeholders to drive informed IT consumption behaviour

Program & Portfolio Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Measure and Communicate PPM Performance

Highest Importance
- Facilitate Portfolio Prioritization
- Manage Programs

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Program & Portfolio Management (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Partner With Stakeholders	Define a Stakeholder Management Approach	4.0	4: the PPM function helps product, project or program managers classify their stakeholders based on their communication styles and challenge stakeholder assumptions when necessary
Steward Investment Portfolios	Facilitate Portfolio Prioritization	4.0	4: the PPM function's support enables portfolio decision makers to align roadmaps with organization objectives, define a target portfolio structure based on the relative importance of business capabilities and reprioritize as the investment roadmap changes
	Manage Risks & Interdependencies	4.0	4: the PPM function frequently seeks input on risk to achieving business outcomes from a diverse det of stakeholders and established risk-escalation rules
	Select & Report Portfolio Metrics	3.0	3: the PPM function aggregates, tracks and reports a mix of standard operational and benefit metrics
Manage Framework & Standards	Track Costs of Initiatives	3.0	3: the PPM function defines standard frameworks to track the overall costs of initiatives
	Create Estimates for Initiatives	3.0	3: the PPM function tailors the approach to estimation and level of support depending on the characteristics of the initiative and uses input from experienced estimators to improve the accuracy of estimates.
	Select & Report Initiative Performance	3.0	3: the PPM function uses standard metrics, tailors its reporting approach to fir context and need, and enables self-service tools for stakeholders

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Program & Portfolio Management (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Drive Transformation Initiatives	Define Programs	3.5	3: programs are proactively defined to manage technical, or resource dependencies related to a common business objective 4: programs are defined top-down to support business capabilities and are assessed on measurable business outcomes
	Manage Programs	4.2	4: the PPM function takes a program-centric view of resource allocation, budge reprioritization and design of the program manager role
	Enable Organizational Change Management	4.0	4: the PPM function sequences change initiatives and adjusts change management approached to drive adoption
Manage the PPM Function	Manage the Mandate of the PPM Function	4.5	4: the PPM function defines its activities as a set of services to meet t he varied needs of stakeholders 5: the PPM function reshapes its mandate or temporarily fixes the way it engages with key stakeholder to align with the evolving priorities of the digital business
	Measure & Communicate PPM Performance	2.8	2: the PPM function reports basic initiative-level metrics to stakeholders at regular intervals 3: the PPM function tracks the function’s performance against operational and strategic objectives and provides customized reports to stakeholders

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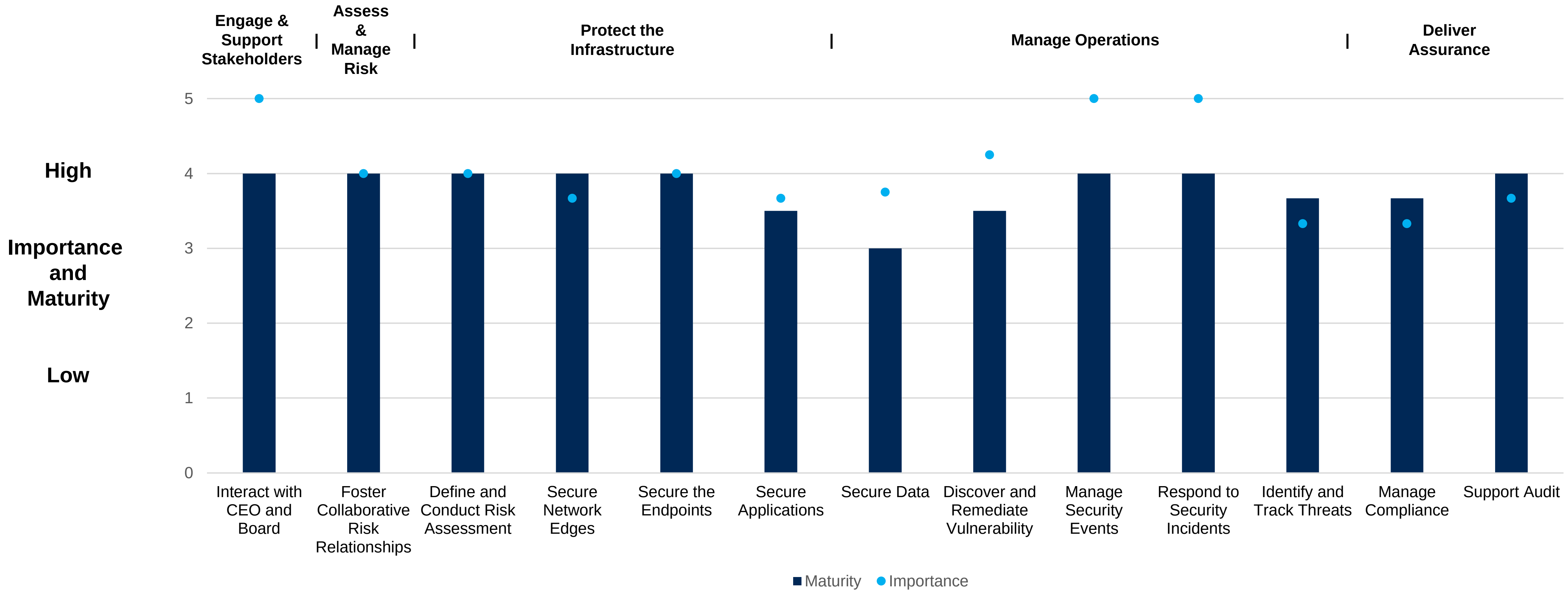
Security & Risk Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Secure Data
- Secure Applications
- Discover and Remediate Vulnerabilities

Highest Importance
- Interact with CEO and Board
- Manage Security Events
- Respond to Security Incidents

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Security & Risk Management (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Engage & Support Stakeholders	Interact with CEO & Board	4.0	4: SRM develops and communicates standardized reports in business-friendly language, aligned to business objectives that are made available to the board and CEO on a regular basis
	Foster Collaborative Risk Relationships	4.0	4: SRM works with other stakeholders on future challenges and encourages staff across functions to minimize activity duplications and maximize collaboration
Assess & Manage Risk	Define & Conduct Risk Assessments	4.0	4: SRM has defined a risk assessment process that periodically reassesses risk and aggregates findings against a defined taxonomy
Protect the Infrastructure	Secure Network Edges	4.0	4: SRM ensures network access and network traffic within networks are controlled and monitored
	Secure the Endpoints	4.0	4: endpoint security controls are expanded to include detection and response
	Secure Applications	3.5	3: SRM implements automated discovery and security assessment for applications 4: SRM collaborates with application development to implement application security policies and implements monitoring automation
	Secure Data	3.0	3: SRM identifies threats and compliance issues to implement protection and monitoring controls

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Security & Risk Management (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage Operations	Discover & Remediate Vulnerabilities	3.5	3: SRM prioritizes vulnerabilities based on business context and monitors patching effectiveness 4: SRM uses threat intelligence to further prioritize vulnerabilities
	Manage Security Events	4.0	4: SRM regularly assesses monitoring effectiveness to increase alert accuracy and uses event and incident data to improve detection accuracy
	Respond to Security Incidents	4.0	4: SRM works with other functions to formalize all aspects of crisis response plans, maintains detailed response playbooks for a variety of incidents and conducts tabletop test on plans
	Identify & Track Threats	3.7	3: SRM uses analytics to identify patterns of threats, reverse-engineers attached to identify indicators of compromises and considers scenarios of future attacks to tailor detection efforts 4: SRM combines internal and external data to develop hypotheses of future attacks, applies attribution techniques across multiple platforms and timelines, and compiles common attacker profiles to tailor monitoring of future attacks
Deliver Assurance	Manage Compliance	3.7	3: SRM typically tracks current regulations and works closely with internal experts to ensure compliance 4: SRM centrally tracks current regulations and works closely with internal and external experts to ensure compliance
	Support Audit	4.0	4: support of audit activities is based on prioritized audit objectives. Partial data collection is based on time and effort analysis to meet audit support requirements

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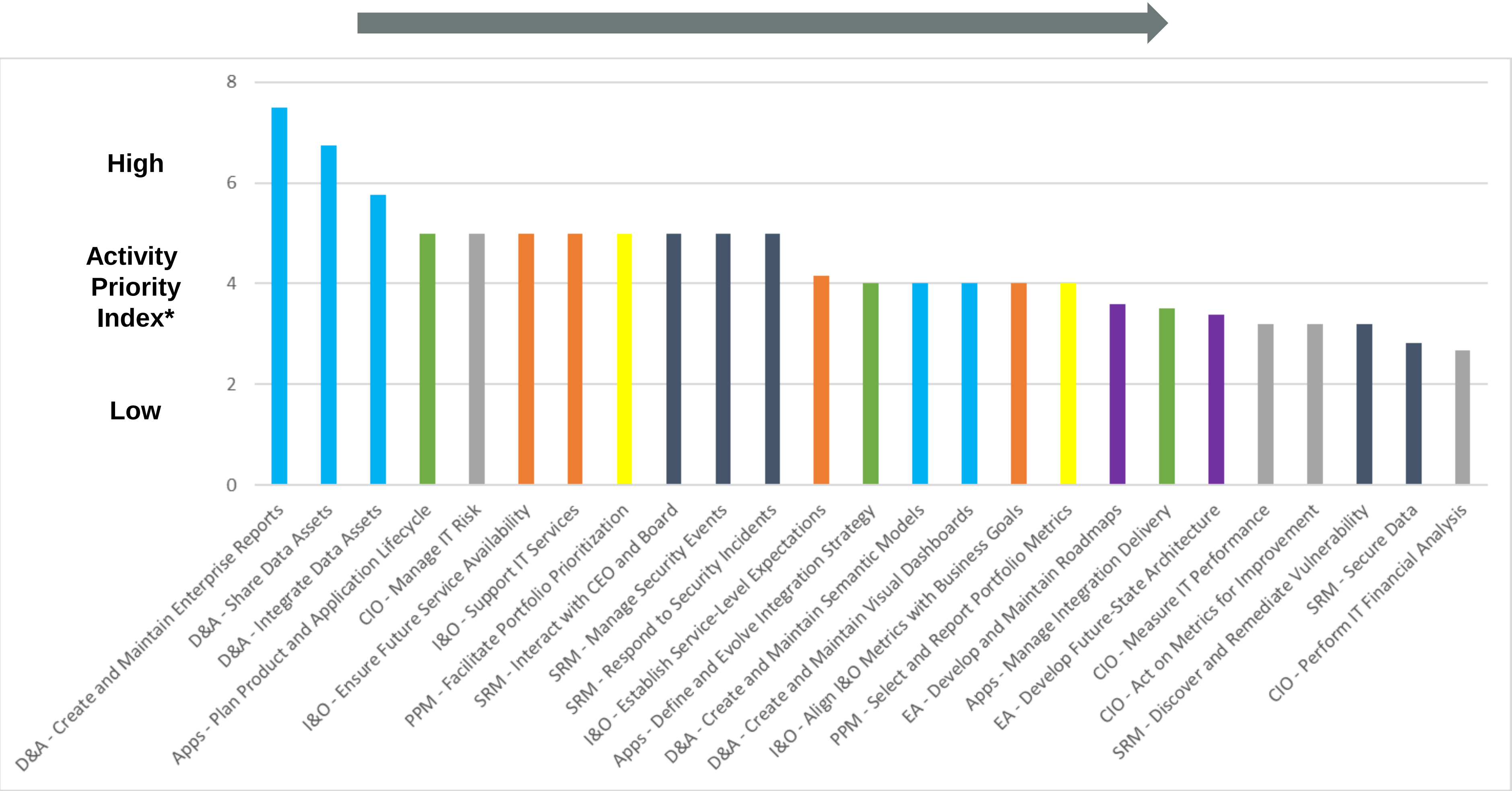
Top 25 Improvement Opportunities: Activity Priority Index (API)

The Activity Priority Index (API) represents an order of priority for the IT functions, based on which below are least mature and of greatest importance for Toronto Hydro

Highest to Lowest Priority Areas for Improvement



*Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.

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E1 Capital Expenditure Plan Introduction

Section E consists of the following sections that details Toronto Hydro's 2025-2029 Capital Expenditure Plan:

- **Section E1 – Capital Expenditure Plan Introduction:** Provides basic information about the expenditure plan, including drivers and expenditures by category.
- **Section E2 – Capital Expenditure Planning Process Overview:** Provides a detailed explanation of the business planning process, including customer engagement, that Toronto Hydro undertook to develop the 2025-2029 Capital Expenditure Plan.
- **Section E3 – System Capability Assessment for Generation Connections:** Provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed energy resource ("DER") connections.
- **Section E4 – Capital Expenditure Summary:** Provides a comprehensive summary of Toronto Hydro's capital expenditures over the current 2020-2024 and future 2025-2029 rate periods, including explanatory notes on material variances.
- **Sections E5-E8:** Provides detailed, program-specific justifications and business cases for Toronto Hydro's capital expenditure plan in each of the System Access (E5), System Renewal (E6), System Service (E7), and General Plant (E8) categories.

The following is an introduction to the 2025-2029 Capital Expenditure Plan.

E1.1 2025-2029 Capital Expenditures

Toronto Hydro's capital programs are presented according to the Ontario Energy Board's ("OEB") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022):

- System Access Investments (Section E5);
- System Renewal Investments (Section E6);
- System Service Investments (Section E7); and
- General Plant Investments (Section E8).

In the current rate period, Toronto Hydro's operating parameters shifted from a relatively linear and stable environment to a more dynamic growth-oriented context, predicated on increases in future customer demand driven by an unprecedented energy transition that is creating new and expanded roles for electricity within the economy. In recognition of this evolving landscape, and customers' needs and priorities for the upcoming planning period, Toronto Hydro adopted four focus areas to structure and guide its planning process for 2025-2029, as further described in Section E2:

- **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
- **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
- **Growth and City Electrification:** Necessary investments to connect customers (including DERs) and build the capacity to serve a growing and electrified local economy.
- **General Plant:** Investments in vehicles, work centers and information technology (IT) infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For ease of reference Table 1 below provides a program and segment concordance between these areas of focus and the OEB investment categories per Chapter 5 of the OEB's Filing Requirements.

Table 1: Program & Segment Concordance to OEB Investment Category

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
System Access	Customer and Generation Connections	Load Connections	Growth
		Generation Connections	Growth
	Externally Initiated Plant Relocations & Expansions	Externally Initiated Plant Relocations & Expansions	Growth
	Load Demand	Load Demand	Growth
	Metering	Revenue Metering Compliance	Modernization
		Wholesale Metering Compliance	Modernization
	Generation Protection, Monitoring, and Control	Generation Protection, Monitoring, and Control	Growth
System Renewal	Area Conversions	Rear Lot Conversion	Sustainment
		Box Construction Conversion	Sustainment
	Underground System Renewal - Horseshoe	Underground System Renewal - Horseshoe	Sustainment
		Cable Chamber Renewal	Sustainment

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
	Underground System Renewal - Downtown	Underground Cable Renewal	Sustainment
		Underground Residential Distribution Renewal	Sustainment
		Underground Switchgear Renewal	Sustainment
	Network System Renewal	Network Unit Renewal	Sustainment
		Network Vault Renewal	Sustainment
		Network Circuit Reconfiguration	Sustainment
	Overhead System Renewal	Overhead Infrastructure Resiliency Improvement	Modernization
		Overhead System Renewal	Sustainment
	Stations Renewal	Transformer Stations	Sustainment
		Municipal Stations	Sustainment
		Control & Monitoring	Modernization
		Battery & Ancillary Systems	Sustainment
	Reactive and Corrective Capital	Reactive Capital	Sustainment
		Worst Performing Feeders	Sustainment
System Service	**System Enhancements**	Contingency Enhancement	Modernization
		Downtown Contingency	Modernization
		System Observability	Modernization
	Non-Wires Solutions	Energy Storage Systems	Growth
	Network Condition Monitoring and Control	Network Condition Monitoring and Control	Modernization
	Stations Expansion	Downsview TS	Growth
		Hydro One Contributions	Growth
General Plant	**Enterprise Data Centre**	Enterprise Data Centre	General Plant
	Facilities Management and Security	Facilities Management and Security	General Plant
	Fleet and Equipment	Fleet and Equipment	General Plant
	IT/OT Systems	IT Hardware	General Plant
		IT Software	General Plant
		Communication Infrastructure	General Plant

E1.2 Investment by Category

Tables 2 below compares capital expenditures by investment category for the current 2020-2024 period and the future 2025-2029 rate period. Section E4 provides further explanations of the shifts in planned expenditures over the two rate periods.

Table 2: Planned Capital Investment by OEB Investment Category ($ Millions)

Category	Total 2020-2024	Total 2025-2029	Var. ($)	Var. (%)
System Access	630.0	**1,071.7**	441.7	70%
System Renewal	1,458.2	**1,970.3**	512.1	35%
System Service	225.6	**353.0**	127.4	56%
General Plant	418.6	**562.5**	143.9	34%
Other	55.1	**44.3**	(10.8)	(20%)
Total	**2,787.4**	**4,001.8**	**1,214.4**	**44%**

E1.3 Investment by Trigger Drivers

For categorization purposes, each capital program described in Section E5 through E8 is assigned one or more drivers of work, including a single trigger driver (representing the catalyst for the investment) and typically one or more secondary drivers.[1] Programs are allocated to each of the four investment categories in accordance with their trigger drivers. A description of each trigger driver is provided in the table below.

Table 3: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and DER customers to its system as efficiently as possible in alignment with its obligation under the Distribution System Code. This obligation holds unless it poses safety concerns for the public or employees or compromises the reliability of the distribution system. In situations where the existing infrastructure falls short of enabling a connection, the utility undertakes system expansions or enhancements to accommodate the customer's needs.

[1] The list of capital investment drivers used in this application were developed based on the OEB's example drivers from Chapter 5 of the OEB's Filing Requirements.

Category	Driver	Description
	Mandated Service Obligation	• Toronto Hydro prioritizes full compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• Specific asset types and configurations can become obsolete for a variety of technical and operational reasons. Typically, functionally obsolete assets can no longer be effectively maintained or utilized as intended. Toronto Hydro will act to retrofit or replace these assets within a timeframe that is specific to the unique circumstances of the asset population in question.
	Failure	• Toronto Hydro must reactively repair or replace assets or critical components that have failed while in service.
	Failure Risk	• Toronto Hydro takes proactive measures to identify, assess, and mitigate failure risk within its asset populations. Failure risk is determined by evaluating the likelihood of failure (e.g., by leveraging asset condition assessments) and the likely impact of failure (“criticality”) on various outcomes, including safety, reliability, cost, and the environment. By prioritizing service reliability and ensuring the safety of workers and the public, the utility strives to maintain a robust infrastructure that meets the evolving needs of its customers.
System Service	***Reliability***	• Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions.
	Capacity Constraints	• Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs.
General Plant	***Operational Resilience***	• Toronto Hydro prioritizes the ability to mitigate and recover from disruptions to core business functions. Through robust strategies, contingency plans, and proactive risk management, the utility ensures prompt restoration of operations, minimizing impact and maintaining service continuity.
	System Maintenance and Capital Investment	• Toronto Hydro recognizes the significance of investing in day-to-day operational activities, as doing so enables the utility to prioritize the safety and well-being of its employees while

Category	Driver	Description
	Support	maintaining an environment that fosters efficiency and reliability in delivering essential services.

E2 Capital Expenditure Planning Process Overview

Section E2 explains how Toronto Hydro developed its 2025-2029 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to balance price and other outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.
- **Section E2.3** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.4** focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process to develop program-level expenditure plan proposals to support the utility's asset management outcome objectives.

Detailed justifications for Toronto Hydro's planned capital program expenditures can be found in the sections in E5 through E8 of this Distribution system Plan ("DSP").

E2.1 Business Planning Process

In developing a multi-year investment plan, Toronto Hydro begins from the principle that the utility is entrusted by customers and stakeholders to prepare a responsible plan that balances both price and service quality outcomes. The 2025-2029 Plan achieved that balance through an integrated and iterative business planning process that considered customer feedback from start to finish.

Toronto Hydro's 2025-2029 Capital Expenditure Plan ("the Plan") is an output of the utility's outcomes-oriented, customer-focused business planning process. The Plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. Figure 1 below provides a high-level view of the process as it relates to the Capital Expenditure Plan, and the sections that follow provide an overview of how the elements of the process came together to generate the Plan that forms the basis of Toronto Hydro's 2025-2029 DSP.

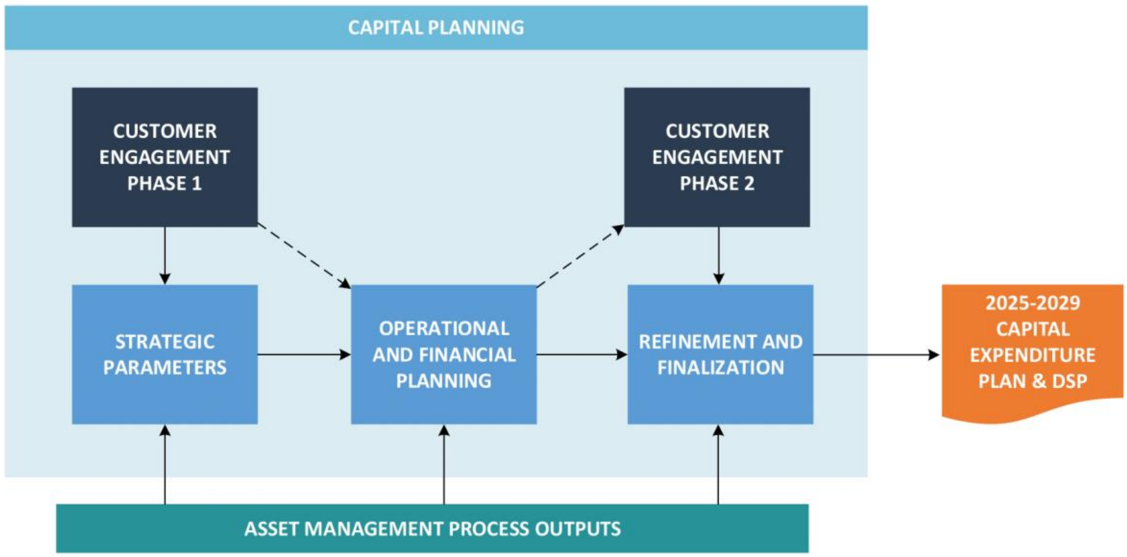


Figure 1: Capital Planning in Business Planning

E2.1.1 Strategic Planning Direction

Toronto Hydro began planning by engaging customers to ascertain their needs and priorities for the 2025-2029 planning period (i.e. Phase 1 of Customer Engagement), and used the customer feedback received to provide strategic direction to the planning process.

Feedback from customers was that price, reliability, and investing in new technology were their top priorities. Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customers are more sensitive to power interruptions and prioritize reducing the total number of outages. Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better in the future.

Customers also expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero, and expect Toronto Hydro to support them in meeting their electrification objectives by ensuring that the system has capacity for growth and by providing them advisory services.[1]

With consideration for customers' needs, priorities and other inputs (discussed below), Toronto Hydro organized its plan around the following investment priorities.

1) **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
2) **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
3) **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
4) **General Plant:** Investments in vehicles, work centers and information technology (IT) infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For each investment priority, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

Table 1: 2025-2029 Performance Objectives

Investment Priority	Key Performance Objectives
Sustainment and Stewardship	• Maintain recent historical system reliability • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Adhere to previous commitments for safety and environmental compliance activities (e.g. removal of at-risk PCBs by 2025; complete Box Conversion by 2026) • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools. • Ensure investment pacing contributes to stable long-term investment requirements for all assets (2030+)

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Exhibit 1B, Tab 5, Schedule 1 – Appendix A.

Investment Priority	Key Performance Objectives
Modernization	• Prioritize investments that will deliver demonstrable benefits to customers, especially enhancements that will improve value-for-money in the long-term (i.e. efficiency) • Improve system reliability through enhanced fault management, leveraging automation and advanced metering through Advanced Metering Infrastructure ("AMI") 2.0 • Enhance system observability across the system, enabling better asset management and operational decision making • Leverage technology to improve customer experience (e.g. reliability, power quality, customer tools, DER integration) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown
Growth & City Electrification	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment) • Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections • Install control and monitoring capabilities for all generators > 50kW • Accommodate relocations for committed third-party developments, including priority transit projects
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code [2], *Occupational Health and Safety Act*[3], CSF, etc.) • Achieve emissions reduction by implementing Toronto Hydro's NZ40 strategy • Support modernization objectives including grid automation and customer experience. • Minimize cybersecurity risks associated with IT/OT infrastructure • Ensure IT infrastructure is available and reliable with minimal service disruption

[2] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[3] *Occupational Health and Safety Act,* RSO 1990, c. O.1

In addition to setting these performance objectives, Toronto Hydro adopted top-down financial constraints to ensure that the principle of balancing price and service quality outcomes remained top of mind throughout the planning process.

1. **Price Limit:** Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges.[4]
2. **Budget Limits**: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period.

In developing these strategic parameters, Toronto Hydro considered a number of inputs, including:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system health demographics and performance;
- long-term asset stewardship needs, including pacing considerations related to resourcing, supply chain, execution constraints, project lead-times, etc.;
- forecasted system use profiles and pressures, including capacity constraints in the short-, medium- and long-term amid increasing demand for load and DER connections;
- detailed demand scenarios reflecting the uncertain long-term trajectory (2050) for the energy system within the City of Toronto;
- safety and environmental risk assessments;
- evolving business conditions and the need to strategically deploy new and enhanced technologies to manage performance risk and take advantage of emerging opportunities to generate value for ratepayers;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including significant upward pressure on material and construction costs in Toronto;
- total cost benchmarking; and

[4] As calculated for the monthly bill of a Residential customer using 750 kWh.

- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary investment strategy options for each capital program. These options generally reflected:

- a cost-constrained "low" option that, depending on the type of program (i.e. sustainment, modernization, growth, or general plant), would involve taking on additional asset risk in the medium-term, delaying or forgoing further modernization or decarbonization benefits, or taking a higher-risk "wait-and-see" approach to investing for growth (i.e. expansion and connections);
- a "high" option, which, depending on the program, would aim to improve system performance and asset risk in the medium-term, strategically accelerate modernization in areas that can deliver long-term reliability and efficiency benefits for customers, or plan for higher growth needs driven by electrification and community energy plans; and
- a middle option, where program-specific trade-offs would be made between costs and benefits, for example by aiming to maintain current levels of asset risk for certain asset classes, or stretching the pace of modernization and associated benefits over a longer time horizon.

Figure 2, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the low or high options for every investment program as compared to the draft plan for 2025-2029.

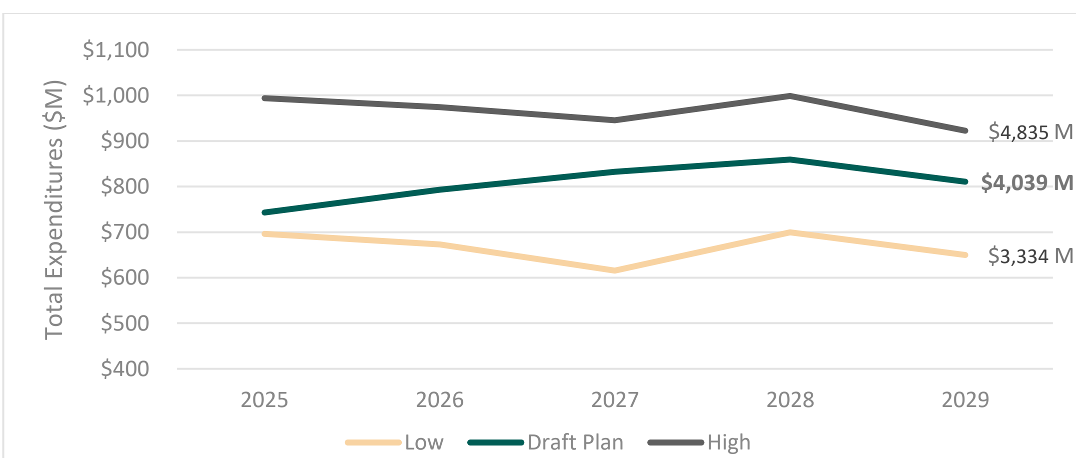


Figure 2: Preliminary High-level 2025-2029 Capital Expenditures Scenarios

Based on the aforementioned inputs, through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price impacts for customers, as informed by the feedback in Phase 1. Toronto Hydro selected the $4,000 million capital budget limit to achieve this balance of keeping rates reasonable without compromising performance.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2025-2029. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital and operational expenditure plans to align with short- and long-term performance objectives, while remaining within the financial constraints and strategic considerations set-out in the strategic parameters.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic objectives in the focus areas of Growth, Sustainment, Modernization and General Plant. From this starting point, an iterative process generated multiple versions of the capital expenditure plan, eventually producing a draft plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan – which on an aggregate basis was higher than the $4,000 upper limit on capital expenditures – and the draft version of the plan were as follows:

- **Growth:** Toronto Hydro reduced Growth proposals for the 2025-2029 period by approximately $191 million. This was largely achieved by taking a more balanced approach to the expected demands placed by electrification and refining forecast estimates in the Customer Connections program. Given the uncertainty surrounding the timing of electrification driven pressures and the energy transition, the utility opted to plan for moderate growth within this rate period while making selective, strategic investments to prepare for further growth in the future. Refinements to program cost and volume estimates also drove minor changes to expenditures within other programs.

- **Sustainment:** Toronto Hydro reduced its Sustainment proposals for the 2025-2029 period by approximately $87 million. It scaled back investments in its Area Conversions program, specifically in the Rear Lot Conversion segment, by approximately $37 million by converting customers with rear lot construction at a more moderate pace in alignment with the Ontario

Energy Board ("OEB's") 2020-2024 Decision and Order.[5] It also reduced investments in the Cable Chamber Renewal segment within its Underground Renewal - Downtown program by approximately $25 million by scaling back the number of poor condition assets addressed in the next rate period and managing failure risk by concentrating on asset locations that carry the highest level of potential failure consequences. Finally, the utility reduced investments in the Underground Renewal – Horseshoe program by approximately $48 million in order to balance reliability and cost pressures, reducing the pace of direct buried cable replacement and feeder conversions within the rate period. These reductions were partly offset by refinements to program estimates within other programs. From the onset, the utility worked to constrain the planned pacing of renewal investment to a minimum level at which it expects it can maintain recent levels of system average reliability (with necessary support from complimentary grid modernization investments), while ensuring prudent management of broader long-term asset risk considerations, including: managing longer-term demographic pressures in certain asset classes; addressing obsolescence risks such as the large remaining population of 4 kV feeders and stations, which are inefficient and poorly suited to meet emerging system demands; and ensuring sufficient funding to support the upsizing of neighbourhood level equipment (e.g. pole top transformers) during renewal projects in order to support electrification of consumer energy demand. A description of how the utility leveraged its asset management processes to appropriately pace and prioritize its Sustainment plan is provided in Sections E2.2 and E2.4 below.

- **Modernization:** Toronto Hydro reduced Modernization expenditures by approximately $191 million over the 2025-2029 period. This reduction was driven by the need to ensure progress towards grid modernization objectives while balancing rate impacts for customers. The reductions were primarily achieved within the System Enhancement program. The Downtown Contingency segment was substantially reduced, focusing efforts in a limited way on creating station switchgear ties between Copeland Station and Esplanade Station within this rate period to manage a subset of contingency concerns within the downtown system. Toronto Hydro expects to pilot innovative solutions such as the Automated Primary Closed Loop distribution system which has the capability to provide a more effective and relatively economical solution to establish feeder ties between stations, thereby delivering longer term system benefits at a reduced cost in the future. Toronto Hydro also reduced the Contingency

[5] EB-2018-0165, Decision and Order (December 19, 2019).

Enhancement segment in order optimize the investment profile of the program over the five years and manage resource and other execution risks. Reductions within the System Enhancement program were slightly offset by refinements to cost and volume estimates within other programs.[6]

- **General Plant:** General Plant expenditures decreased by approximately $11 million as result of adopting a more constrained strategy for the Head Office, as described in the utility's Facilities Asset Management strategy at Section D6.

Overall, in an effort to find the balance between price and progress towards outcomes that customer expect, Toronto Hydro constrained its initial capital plan by approximately $480 million from the beginning to the end of the process. The result was a $4,000 million draft capital expenditure plan for 2025-2029,[7] which was subsequently refined and finalized as described in the next section.

E2.1.3 Refinement and Finalization of the Capital Expenditure Plan

Toronto Hydro presented the draft plan to customers in the Phase 2 Customer Engagement survey to validate whether: (i) the plan aligns with customer needs and priorities and (ii) the balance between price and other outcomes aligns with customer preferences. To that end, the Phase 2 survey solicited customer feedback on Toronto Hydro's overall draft plan and the associated price impacts. 84 percent of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it. A full analysis of the Phase 1 and Phase 2 Customer Engagement results is provided in Section E2.3 below.

To gain additional insight into the preferences of customers relative to trade-offs between price and other key outcome like system health, reliability and customer service, Toronto Hydro provided customers with the key details of the utility's investment plan, broken down into seven key investment options (described in Section E2.3 below). For each of these investment options, the utility described its draft plan and options to spend more or less for faster or slower progress towards key performance outcomes. In response to being asked to make specific trade-offs between price and other outcomes in each of the seven choices within the plan, customers expressed certain

[6] Exhibit 2B, Section E7.1.
[7] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

preferences to increase, maintain or reduce the pace of investment. Toronto Hydro considered this feedback in refining and finalizing its 2025-2029 investment plan.

Along with refining planning assumptions to incorporate new and salient information such as the impact of 2022 actuals, the utility leveraged the results of Customer Engagement Phase 2 to calibrate the pace of investment in certain programs. Overall, the adjustments that Toronto Hydro made to programs between the draft plan and the final plan were as follows:

- **Growth:** Toronto Hydro reduced growth-related expenditures by approximately $57 million over the 2025-2029 period. This was due in part to an additional reduction to the load connections forecast, which was partly offset by increased investment needs identified in the Load Demand program due to incremental scope and revised cost estimates. Toronto Hydro also refined the scope of the Battery Energy Storage Systems segment to reflect insights from the procurement process for battery investments in the current rate period, which resulted in further reductions. In light of customer feedback with respect to trade-offs between price and other outcomes in Growth investments, the utility also reduced the Stations Expansion program by $35 million by deferring the second phase of the Basin TS expansion into the next period.

- **Sustainment:** Toronto Hydro increased Sustainment expenditures by approximately $65 million over the 2025-2029 period due to refinements to program cost estimates including updates for inflationary assumptions and incremental investment needs to address legacy infrastructure and associated failure risk. For example, incremental expenditures were required to address legacy switches in the downtown underground system and to complete all Box Construction feeder conversions in the next rate period. In order to partly offset these increased investment requirements and be responsive to customer preferences gleaned in the Phase 2 engagement, Toronto Hydro reduced $20 million from its stations renewal program by deferring switchgear renewal investments.

- **Modernization:** The Modernization plan increased by $8 million. Increases in the Metering program due to cost refinement and inflation pressures were offset by the decision to reallocate funding for various types of modernization pilot projects to the Innovation Fund outlined in Exhibit 1B, Tab 4.

- **General Plant** General Plant expenditures decreased by approximately $48 million over the 2025-2029 period, the Facilities Management and IT Software programs were reduced by approximately $13 million, and the pace of fleet electrification was lowered by $3.5 million in response to customer preferences expressed through the second phase engagement (see E2.3 below). The remaining decrease is due in large part to an administrative correction made to the Fleet Equipment program that resulted in a $31 million reduction.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[8]

Section E2.2, below, provides an overview of how Toronto Hydro derived the plan from the asset management processes described in Section D of the DSP. Section E2.3 describes the results of the Customer Engagement process and how they informed the DSP. Section E2.4 focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process.

E2.2 Asset Management in Capital Planning

Toronto Hydro primarily derived its 2025-2029 Capital Expenditure Plan based on its Asset Management System ("AMS") for distribution assets, Information and Operational Technology ("IT/OT") Asset Management, and Facilities Asset Management described in Section D. As discussed in Sections D1 and D3, the utility develops its system investment programs through the annual Investment Planning and Portfolio Reporting ("IPPR") process. This process leverages the various asset lifecycle optimization and risk management methodologies discussed in Section D3 to produce capital programs and expenditure plans that are optimized to support the utility's customer-focused outcome objectives. The scenarios and recommendations developed in IPPR become inputs to business planning (discussed in the previous section), where program expenditure plan proposals are further refined, leveraging the same AMS tools and outputs.

Figure 3 below (originally presented in Section D3.4) is a simplified view of the major program planning elements within the IPPR process. It depicts the cyclical nature of program development and the integration points with customer engagement activities.

[8] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

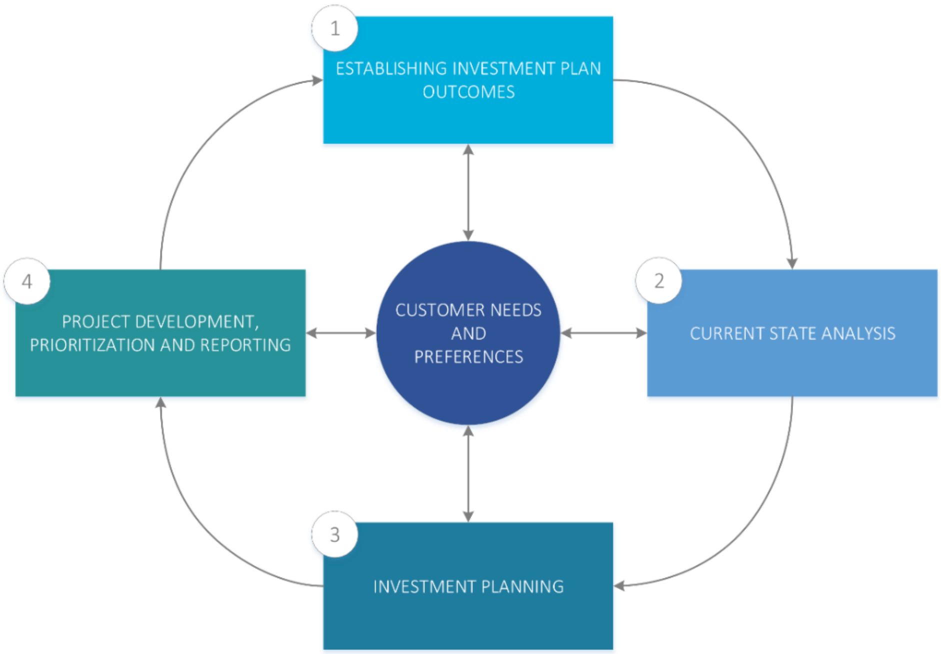


Figure 3: The IPPR Program Development Framework

Step one in the figure above, which involved selecting the desired outcomes and objectives for the 2025-2029 investment plan, was described in the previous section (E2.1). The following sections explain how each of the remaining three elements in this process contributed to the production of the 2025-2029 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Needs Assessment for 2025-2029

Concurrent with the development of the utility's asset performance objectives (summarized in Table 1 above and also discussed in Section D1.2.1.1), Toronto Hydro performed an Asset Needs Assessment to develop a baseline understanding of the current state of its distribution system. As explained in Section D3, the Asset Needs Assessment includes a Current State Assessment ("CSA") and a System Needs and Challenges Review. The results of these analyses informed the capital budget limit that Toronto Hydro set in the strategic parameters for the business plan.

E2.2.1.1 Current State Analysis Results

The Current State Analysis ("CSA") produced foundational information, including asset demographics (i.e. counts, age and nameplate attributes) and condition demographics. These data points informed program pacing and prioritization decisions throughout business planning.

1. Asset Condition Demographics

The utility examined the current state of its asset condition demographics – derived from its Condition Based Risk Management ("CBRM") methodology – to determine which asset classes were showing the greatest signs of deterioration, and took this into account in establishing planning scenarios. Table 2 below shows the percentage of assets in the worst condition bands (HI4 and HI5) summarized by major system category.

As illustrated by comparing the 2022 Actual condition to 2017 Actual condition, Toronto Hydro managed to improve or approximately maintain the HI4/HI5 condition profiles for major assets on its network and underground systems, as well as within its stations. This was accomplished through sustained capital investment and maintenance activities over the last five years. Over the same period, the utility saw a moderate deterioration in condition on its overhead system, driven largely by deterioration in the wood pole population. As discussed in Section E4.1.2, this decline in overhead system health was driven in part by the decision to restrain renewal expenditures by deferring some work into 2025-2029 in order to balance cost pressures across the overall Capital Expenditure Plan. Toronto Hydro managed this by shifting temporarily to a spot replacement approach focused primarily on PCB removal and delaying larger area rebuilds that are required to address deteriorating poles and switches as well as obsolete 4 kV feeders.[9]

Table 2: CBRM Results by System (% of asset population in HI4/HI5 condition as of year-end)

System Category	2018 CBRM Outputs		2023 CBRM Outputs	
	2017 Actual	2024 Projection (no intervention)	2022 Actual	2029 Projection (no intervention)
Network	5%	23%	4%	16%
Overhead	6%	34%	9%	30%
Stations	8%	44%	3%	28%
Underground	3%	7%	3%	10%

As shown in Table 2 above, Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. For Toronto Hydro's high-volume overhead and underground

[9] Note that Toronto Hydro found that it was necessary to also defer work within the Underground System Renewal – Horseshoe program in favour of PCB at-risk equipment removals. In this case, it has largely been underground cable replacements that the utility has deferred to 2025-2029. Since underground cables do not have a condition model, the effect of cable replacement deferrals on the growing backlog of cables at risk of failure is not captured in Table 2.

asset populations, the rate of asset deterioration expected by the end of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the network system is exhibiting a slower rate of deterioration compared to 2018, two additional drivers of investment should be noted: (1) the continuing prevalence of non-submersible network units, which are at a higher risk of catastrophic failure due to flooding regardless of their condition; and (2) an anticipated wave of network demographic issues beyond 2029, with over 50 percent of network units projected to be at or beyond end of useful life by 2034 without intervention. As for Toronto Hydro's major stations assets, an observed improvement in the rate of deterioration is the result of the utility's focused effort in recent years to eliminate high risk, obsolete stations assets including oil circuit breakers. Despite these ongoing efforts, the CBRM model projects a 25-percentage-point increase in the share of HI4/HI5 assets for the station asset population by 2029, which equates to hundreds of major stations assets, the vast majority of which are of obsolete technology types.[10]

Toronto Hydro set-out to develop a risk-calibrated plan that would invest the minimum necessary to manage reliability performance in light of condition-related pressures, and prevent the accumulation of a backlog of assets that are at risk of failure or otherwise need to be upgraded. Asset renewal backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as inefficiencies in work execution. Such inefficiencies stem in part from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through proactive investment. This was one of the key considerations in the utility's selection of its capital budget limit for business planning. The Portfolio Planning section below (E2.2.3) provides additional details on how asset condition informed the pacing of investment in Toronto Hydro's 2025-2029 Capital Expenditure Plan.

2. Assets Past Useful Life

As discussed in Section D3.2, to assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets across the system that are operating at or beyond useful life (the Assets Past Useful Life metric, or APUL). The age demographics of the system as of the beginning of 2023 are summarized in Figure 4 below.

[10] For a detailed discussion of the various drivers for the proposed stations renewal pacing, refer to Exhibit 2B, Section E6.6.

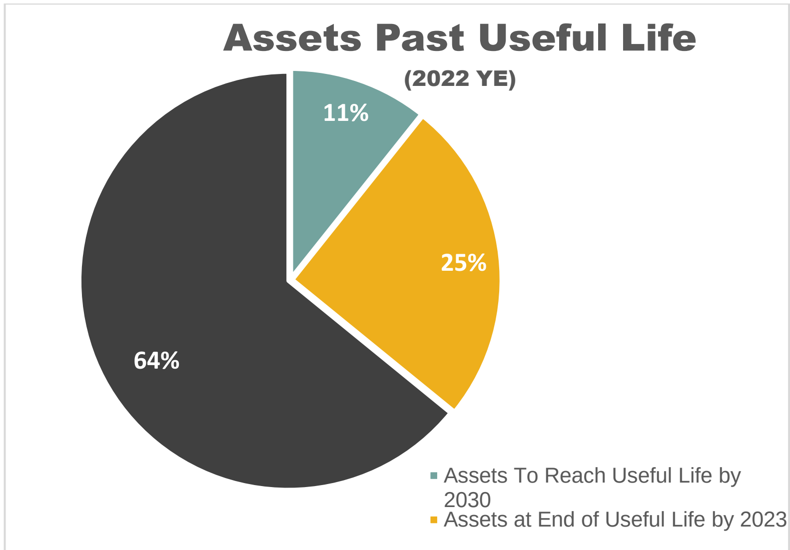


Figure 4: Percentage of Assets Past Useful Life

In 2018, Toronto Hydro's percentage of assets past useful life was 24 percent, with an additional nine percent forecasted to reach expected useful life by 2025. At an aggregate level, and as a direct result of Toronto Hydro's ongoing renewal efforts in recent years, the APUL measure has been relatively stable. However, it should be noted that even a single percentage point in the APUL measure represents future asset replacement needs in the order of hundreds of millions of dollars. Approximately a quarter of the utility's asset base continues to be operating beyond its expected useful life, and an estimated additional 11 percent will reach that point by 2030, which is two percentage points higher than the equivalent rate of deterioration projected in 2018, indicating that a significant proactive renewal program continues to be necessary to sustain overall demographics at current levels and prevent the APUL backlog from increasing.

An overall increase in the APUL backlog would result in a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

E2.2.1.2 System Needs and Challenges Review

In addition to the information generated by the CSA, Toronto Hydro considered a number of other indicators of system investment need, including system utilization, connection capacity, distributed generation forecasts, legacy asset profiles (e.g. lead cable replacement needs), regional planning considerations, grid modernization objectives, and other factors. The utility developed strategic investment scenarios for each of these issues, which in turn informed the capital expenditure plan scenarios discussed in Section E2.1.

Section D2 provides an overview of the various considerations resulting from the System Needs and Challenges Review. Section D4 describes Toronto Hydro's strategy to manage growth and development in an uncertain future as a result of electrification and decarbonization of the utility grid. It outlines how additional drivers and enhanced scenario-based load forecasting techniques impacted the 2025-2029 investment plans. Section D5 provides a comprehensive overview of the utility's Grid Modernization Strategy for 2025-2029. Section E2.3.3 provides additional insight into the strategies for addressing these issues in the 2025-2029 Capital Expenditure Plan.

E2.2.1.3 System Reliability Performance and Projection Scenarios

System reliability is an important customer-focused outcome and a lagging indicator of performance, including the effectiveness of the subset of Sustainment and Modernization investments that are primarily directed toward preventing outages and shortening outage duration (e.g. direct-buried cable replacement, Contingency Enhancement, etc.). Although Toronto Hydro's renewal and modernization efforts over the last decade have led to improvements in reliability performance that began in the mid-2000s, more recently this performance has plateaued. As shown in Figures 5 and 6, the rate of improvement in frequency and duration of outages began to slow in the last rate period, prior to a slight deterioration in reliability performance experienced from 2020 to 2022.

During the period of 2020-2022, Toronto Hydro experienced a rise in reliability impacts caused by a range of factors. The increase in SAIFI was driven by factors including Foreign Interference (especially animal contacts), Defective Equipment (including outages attributed to underground cable and cable accessories, overhead switches, overhead conductors, as well as poles and pole hardware failures), and Tree Contacts. The largest individual contributor to the increase in SAIFI was Unknown impacts. Unknown outages are typically short-duration, high-impact outages that are restored through SCADA controlled devices. While Toronto Hydro makes its best effort to investigate these events, it is not always possible to pinpoint the exact cause. The majority of these outages are usually non-permanent and self-clearing, stemming from potential causes including animal contacts, tree contacts, and emerging equipment failures.

With respect to SAIDI, Foreign Interference (including outages attributed to animal contacts, vehicles, and foreign objects) was a substantial contributor to the increase in SAIDI during the aforementioned period. Along with Foreign Interference, Defective Equipment (particularly underground cable and cable accessories, and overhead switch failures), Unknown impacts, and Tree Contacts have also played a material role in the observed increase in SAIDI. Further information regarding Toronto Hydro's historical reliability performance is available in Exhibit 2B, Section C.

Starting in January 2022, in an effort to improve reporting accuracy, Toronto Hydro began leveraging Oracle’s Network Management System (“NMS”) – serving as an upgrade to its existing Outage Management System – as part of its reliability audit process to capture improved outage information and address limitations within the Interruption Tracking Information System (“ITIS”). As part of the multi-year NMS upgrade initiative, Toronto Hydro plans to implement a new commercial software solution, Oracle’s Utility Analytics (“OUA”), which will serve as the future successor to ITIS for reliability reporting. Further discussion on the impacts of OUA is provided in Exhibit 2B, Section C.

These upgrades continue to improve the data quality and accuracy of Toronto Hydro’s interruption tracking and reporting. Some of these changes have resulted in higher reliability trends in 2022 when compared with historical years. This includes an increased number of outages affecting small numbers of customers and a higher number of scheduled outages reported, impacting both SAIFI and SAIDI performance.

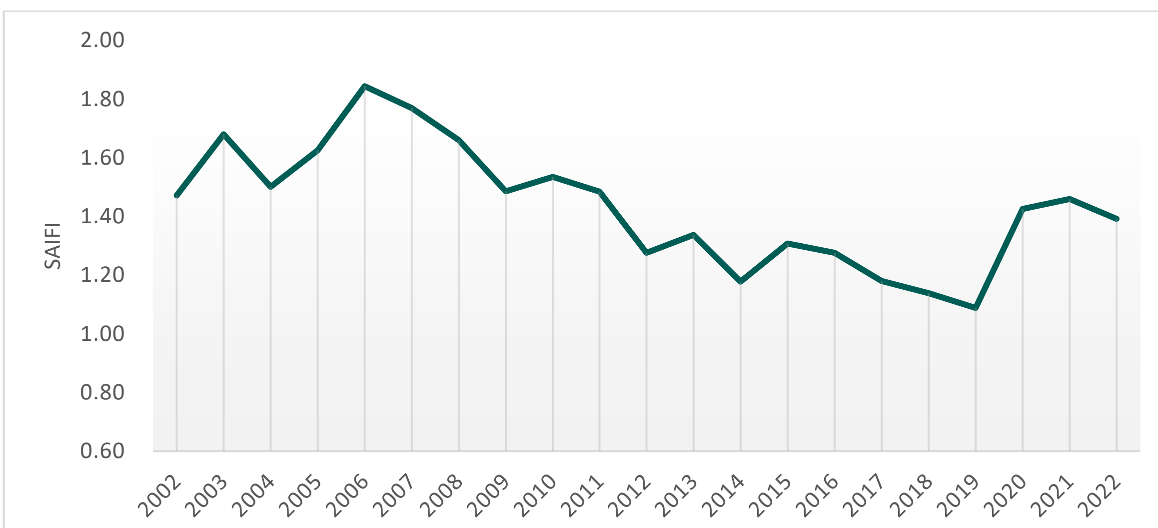


Figure 5: Historical SAIFI (Excluding MEDs and Loss of Supply)

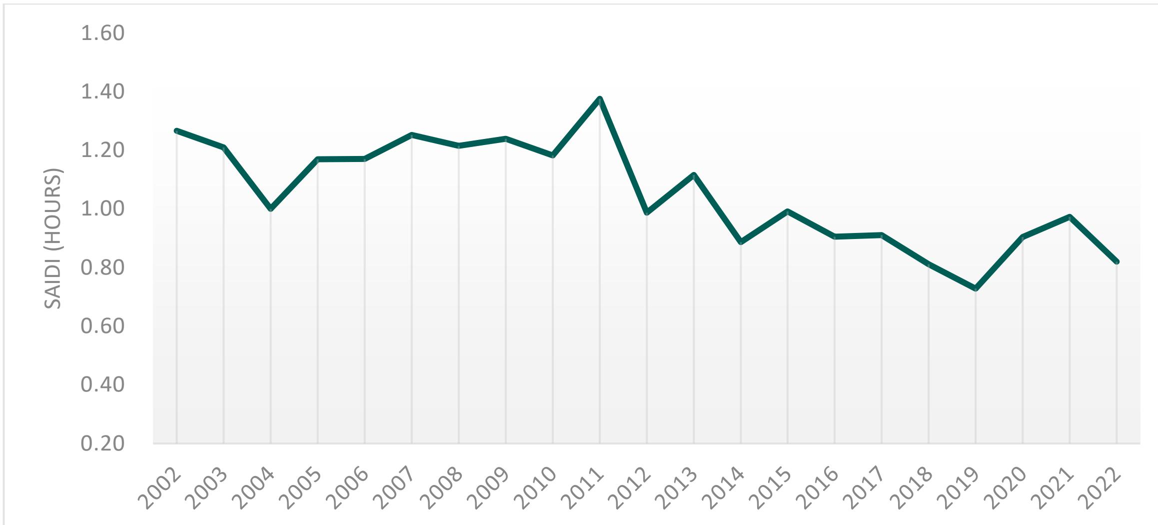


Figure 6: Historical SAIDI (Excluding MEDs and Loss of Supply)

Overall, the utility drew the following key conclusions from recent historical reliability trends and associated asset demographics:

1. **Defective Equipment continues to be the most dominant contributor to reliability performance (SAIDI and SAIFI),** with only Unknown outages having a roughly equivalent impact on SAIFI in the last three years. Asset condition and age demographics are important leading indicators of future Defective Equipment cause code performance. As discussed above (E2.2.2.1), Toronto Hydro's demographic models show that, for the 2023-2029 period, population-level risk accumulation related to asset deterioration will be about as rapid as it was projected to be over the equivalent 2018-2024 period, and in parts of the system where defective equipment has a significant impact on day-to-day reliability (e.g. the underground horseshoe system), the rate of deterioration could in fact be higher. It should be noted that Toronto Hydro's investment plan for the underground and overhead horseshoe systems will continue to be partially skewed toward PCB at-risk equipment replacement activities in 2023, 2024 and 2025, meaning that a full return to primarily reliability-focused sustainment investments will not occur before 2026. With all of these factors in mind, and with the goal of ensuring that sustainment investments are sufficient to maintain reliability over the rate period and the longer-term, the utility concluded that it would be necessary to increase sustainment expenditures in the 2025-2029 period.

2. **General reliability performance has plateaued in recent years following a sustained period of improvement.** From the beginning of the utility's concerted ramp-up in system renewal activities (circa 2007), Toronto Hydro had a focus on eliminating non-standard equipment and system configurations with acute failure risks (e.g. fibre-top network units), and has focused on addressing areas of the system with highly concentrated reliability performance challenges. As a result of the success of these programs, the demographic risk challenges that the utility faces are now more diffuse in nature, meaning that it would likely take a much greater level of sustainment investment (and maintenance expenditures) to drive material year-over-year improvements in Defective Equipment outages in the next decade. At the same time, as discussed in the Grid Modernization Strategy overview (Section D5), there are evolving systemic challenges such as climate change and electrification which Toronto Hydro expects will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy. With these broader trends in mind, the utility concluded that the 2025-2029 investment period would demand a greater emphasis on modernizing the grid, leveraging technologies such as SCADA-operated switches and reclosers, distribution sensors, and advanced distribution management tools to not only continue to improve the customer's overall reliability experience within the rate period, but establish the foundation for full-scale grid automation in 2030 and beyond, ensuring the utility is prepared to deliver stable reliability performance as climate change and electrification pressures accelerate.

Based on these conclusions and related observations from Customer Engagement, the utility set-out to develop an investment plan for 2025-2029 that would (1) include the minimum level of sustainment investment required to maintain the recent average historical frequency of outages caused by Defective Equipment (as represented by the SAIFI Defective Equipment measure), and (2) accelerate ongoing investments in the modernization of the grid in order to improve – in both the short and long-term – the overall customer reliability experience (as represented by the SAIDI measure excluding Major Event Days, Loss of Supply, and Scheduled Outages).[11] Toronto Hydro's

[11] As discussed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro has temporarily removed the Scheduled Outages cause code from its custom SAIDI performance measure for the 2025-2029 period due to major forecasting uncertainty for this cause code caused by the recent implementation of OUA, coupled with the underlying expectation that Scheduled Outages will increase in the 2025-2029 period as the result of a larger planned work program.

2025-2029 forecasts and targets for both of these measure can be found in Exhibit 1B, Tab 3, Schedule 1.

E2.3 Customer Priorities, Needs and Preferences in Capital Planning

As described in Exhibit 1B, Tab 5, Schedule 1, Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement study, which was structured in two phases:

- In **Phase 1,** Innovative used a range of techniques to assess customers' needs and preferences. This was an iterative process - initial qualitative (exploratory focus groups) informed the questions that were put to customers in subsequent telephone and online surveys. These surveys (directed at residential, small business, commercial & industrial, and Key Accounts customers) provided quantitative statistically-valid results. The results of this phase directly informed the strategic planning direction for the business plan and informed decision-making throughout the planning process that produced the draft capital expenditure plan.
- In **Phase 2**, Innovative took Toronto Hydro's entire draft plan (including capital & OM&A expenditures) back to customers to solicit customer feedback on seven key investment options, including trade-offs between price and other outcomes. The utility used the results of this phase to refine and finalize its plan.

Further details on the engagement process, the methods used, improvements, and the engagement results can be found in Exhibit 1B, Tab 5, Schedule 1 ("Customer Engagement") and in the final report from Innovative ("the Innovative Report"), Appendix A to that schedule. The following sections provide a detailed overview of how the Customer Engagement results are reflected in the 2025-2029 Capital Expenditure Plan.

E2.3.1 Phase 1 Customer Engagement: Needs and Priorities

The Phase 1 Customer Engagement identified customer needs and priorities in relation to Toronto Hydro's programs and services for the 2025-2029 planning period. Based on low-volume (i.e. residential and GS < 50 kW) customer focus groups conducted at the beginning of Phase 1, in conjunction with an audit of Toronto Hydro's past and ongoing customer engagement efforts, the following set of customer priorities was identified:

1) Delivering electricity at reasonable distribution rates
2) Enabling customers access to new electricity services
3) Ensuring reliable electrical service (including power quality for Key Account customers)
4) Ensuring the safety of electrical infrastructure;
5) Expanding the electrical system so that customers can reduce their impact on climate change by using electricity;
6) Helping customers with conservation and cost savings;
7) Investing in new technology that could help either reduce costs or better help withstand the impacts of adverse weather
8) Minimizing Toronto Hydro's impact on the environment
9) Providing quality customer service and enhanced communications
10) Replacing aging infrastructure that is beyond its useful life.[12]

In addition to identifying and categorizing customers' priorities, Innovative gathered feedback on how customers ranked these priorities. While customer preferences varied somewhat across rate classes, the overall feedback centered around the following common themes:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customer are more sensitive to power interruptions and prioritize reducing the total number outages.
2. **New Technology:** Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better, even if the benefits aren't immediate, as along as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero—and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

[12] Exhibit 1B, Tab 5, Schedule 1, Appendix A, page 5

This feedback informed Toronto Hydro's strategic planning direction, including the four investment priorities around which Toronto Hydro's plan is organized: **Sustainment, Modernization, Growth and General Plant**. As discussed in Section E2.1 above, the utility sought to deliver on customer needs and expectations by setting an upper capital expenditures limit that established a balance between keeping rate increases low while ensuring reliability performance and preparing the system for key pressures such as electrification and climate change in a prudent manner. Toronto Hydro concluded that a sustainment level of capital expenditures within its system renewal type investments would provide the minimum funding necessary to:

- maintain reliability over the period consistent with historical average;
- maintain long-term performance by preventing asset failure risk from increasing over the period;
- deliver targeted improvements to customers with below average reliability service; and
- maintain or, in targeted situations, improve upon the utility's performance in other priority areas (e.g. Customer Service, Safety, etc.).

Toronto Hydro also identified the need to invest in the system in 2025-2029 to prepare for increased electrification demands and technological changes expected in the near future. As explained in Section E2.2.1, the utility refined these strategic parameters into specific asset management objectives for the 2025-2029 period (see Table 1) and developed a draft business plan to achieve these objectives. The following subsections describe how each of these objectives aligns with specific Phase 1 Customer Engagement results.

E2.3.1.1 Financial Outcomes/Price

When customers were asked to rank their top three priorities, 46 percent of customers chose price, followed by reliability and investing in new technology at 45 percent each.[13] As compared to residential customers, small business customers appear to be more price sensitive. For small business customers, price is still the clear priority by a strong margin at 54 percent – followed by investing in new technology (40 percent) and reliable service (33 percent).

Commercial and Industrial ("C&I") customers (i.e. GS > 50 kW) expressed preferences similar to residential customers and prioritized reasonable rates and reliable services almost equally – at 50

[13] *Ibid.,* at page 5

percent and 48 percent respectively. This was followed by grid capacity expansion for climate action at 33 percent.

As discussed in detail in E2.1 and E2.2, Toronto Hydro developed a capital plan with necessary trade-offs to strike balance between price and performance/service outcomes that align with customer needs and priorities including: the overarching customer priorities of keeping rates reasonable, maintaining average reliability now and in the long-term, improving resiliency (outage duration), and investing in new technology in the 2025-2029 period. Leveraging the outputs of its asset management tools and processes, Toronto Hydro's plan was calibrated to find the right balance between these key objectives.

E2.3.1.2 Reliability

1. Customer Needs and Priorities

Reliability is becoming an increasingly important priority (on par with price) for residential customers, as compared to five-years ago when the utility conducted a similar customer engagement survey in the course of preparing the 2020-2024 Distribution System Plan and rate application.

When asked specifically about different types of reliability investments all customers, with the exception of Key Accounts, prioritized reducing the length of outages over reducing the number of outages. Residential and small business customers were particularly focused on the reliability impacts of extreme weather events, with a particular emphasis on the need to reduce restoration times in extreme weather events (70 percent and 60 percent respectively).[14]

Overall, Key Account customers prioritized reliable service including power quality (69 percent), followed by reducing outage restoration in extreme weather (52 percent). When asked about reliability investments specifically, the focus was on reducing the number of outages (78 percent) and improving power quality (73 percent). This focus on reducing outages reflects the practical reality that for large business customers any interruptions can be costly due to loss of product, or health and safety issues.

2. Plan Alignment

Toronto Hydro's objectives for its 2025-2029 Capital Expenditure Plan are aligned with and responsive to the customer feedback summarized above. When it comes to reliability performance,

[14] *Ibid.* at page 8.

the utility is balancing price with minimum investments to manage, and where appropriate, reduce asset failure risk through sustainment investments in order to maintain overall SAIDI and SAIFI performance over the plan period as discussed in E2.1 and E2.2 above.

Asset failure risk is assessed by leading indicators like asset condition. Section E2.2 describes the various ways in which the goal of either maintaining, or in some cases reducing, the level of asset risk informed the pacing of Toronto Hydro's investment programs. For example, the utility's pacing of pole replacement for the 2025-2029 period is intended to manage the deterioration of condition demographics of wood poles, which is a key issue for the overhead system. Similarly, Toronto Hydro plans to pace direct-buried cable replacement with the intention of preventing the significant reliability risks related to this asset type from increasing to an extent that would result in deteriorating service and high reactive repair costs over the long-term.

Toronto Hydro's plan also includes investments to improve the resiliency (i.e. the ability to handle emergency events) of the system and utility operations, which aligns with feedback received from residential, small business, and C&I customers. These investments are discussed throughout Section E2.2 and include targeted relocation or undergrounding of critical overhead infrastructure (Section E6.5), the renewal of major stations assets in the downtown core (Section E6.6), modernization of the network system (Sections E6.4 and E7.3), and investment in grid intelligence technologies for contingency enhancements and improved system observability (Section E7.1).

Available capacity is another leading indicator of reliability performance and the ability of the system to handle contingency events. This is especially true given accelerating pressures driven by electrification, which may result in higher asset utilization and subsequent degradation. It is also an important indicator of Toronto Hydro's ability to connect customers and carry-out planned capital and maintenance work efficiently. Toronto Hydro plans to maintain current performance for available capacity through investments in the Stations Expansion,[15] and Load Demand programs.[16]

E2.3.1.3 Investments in New Technology

1. Customer Needs and Priorities

Both Residential and Small business customers prioritize investing in new technology among their top three priorities. When asked specifically about different kinds of investments in new technology,

[15] *Supra* note 15.
[16] Exhibit 2B, Section E5.3.

residential, small business and C&I customers all prioritized investments in new technology that can help Toronto Hydro find efficiencies and reduce customer costs over other types of investments.

In addition, customers across all rate classes support:

- Investing in new technology that would make the system better even if there is an increase to customer rates, as long as Toronto Hydro is clear about the cost to customers and the potential benefits; and,
- Investing in technology that might not provide an immediate benefit but will in the future.

2. Plan Alignment

Toronto Hydro's plan includes paced investment in new technology to improve system performance and reduce costs over time. When it comes to the distribution grid, including system planning and operations, Toronto Hydro's 2025-2029 strategy for deploying new technology (i.e. its modernization strategy) is focused primarily on the steady deployment of industry proven technologies (e.g. reclosers, switches, smart meters, analytics) which the utility has prioritized and paced based on the expectation that they will (1) deliver benefits to customers in the near-term (e.g. improved reliability and operational efficiency), while (2) laying the foundation for more advanced use cases that will deliver greater benefits and essential capabilities in 2030 and beyond (e.g. fully automated "self-healing" grid capabilities; more advanced DER management capabilities to optimize DER value to the grid).

The investments that constitute Toronto Hydro's 2025-2029 Grid Modernization Strategy are largely an extension of the continuous modernization efforts which have delivered benefits for customers over the last decade. For example, a key part of Toronto Hydro's *Grid Readiness* portfolio within its 2025-2029 Grid Modernization Strategy (Section D5) is the Flexibility Services program (discussed in detail in Section E7.2.1). For this program, Toronto Hydro plans to build on the historical success of its Local Demand Response initiative by expanding the use of distributed resources for demand response purposes (i.e. flexibility services). Flexibility Services is a type of programmatic Non-Wires Solution which leverages customer-owned flexible assets to provide the utility with tools for managing capacity constraints. The program also provides customers with new revenue mechanisms and opportunities to engage with their distribution company. While Toronto Hydro expects the expansion of this program to have immediate benefits for customers in the 2025-2029 period (e.g., capacity risk mitigation in areas with local constraints; avoidance and deferral of capital investment), the expansion of this program (and implementation of the *Grid Readiness* portfolio plan more broadly) will also be a crucial and necessary step in accelerating the utility's journey toward leveraging DERs in real-time and at scale – a capability that will be necessary to navigate the energy transition effectively and efficiently for customers in the long-term.

As detailed in Section D5, Toronto Hydro's 2025-2029 Grid Modernization Strategy follows a similar approach for all three major strategic portfolios (*Grid Readiness, Intelligent Grid* and *Asset Analytics & Decision-making*). Toronto Hydro is building on the utility's considerable experience deploying smarter technologies to deliver immediate benefits in 2025-2029, while laying the groundwork for more sophisticated capabilities and benefits that will be essential to maintaining performance and meeting heightened customer and stakeholder expectations for the electricity system beyond 2030.

Toronto Hydro is planning to continue with a similar approach for its corporate service functions and customer-facing service operations in 2025-2029. The utility plans to make paced technology investments to improve data quality, develop new insights and analytics, automate business and customer-facing processes, and deploy digital workforce tools to enhance the efficiency of day-to-day business operations and keep up with evolving customer needs and preferences for services and engagement.

As described in Section D8 ("Information Technology ("IT") Investment Strategy"), Toronto Hydro has a rigorous Enterprise Technology Portfolio ("ETP") framework to ensure consistency in IT investment decisions, establish and maintain governance of investments and achieve alignment with the utility's strategic objectives and target outcomes. Toronto Hydro intends to continue to apply a flexible and agile approach to its IT investments, leveraging the ETP framework and associated technology roadmaps to ensure investments are prioritized with the goal of delivering the appropriate balance of immediate and long-term outcomes for customers. For more details on planned IT/OT investments for the 2025-2029 period, refer to Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17.

E2.3.1.4 System Capacity Investments

1. Customer Needs and Priorities

Across all rate classes, customers support proactive investment in system capacity to ensure that high growth areas do not experience a decrease in reliability. Key Account and C&I Customers showed particularly strong support for these investments.

When asked to identify their general priorities, 33 percent of C&I customers identified the need to expand the capacity of the grid such that they can reduce their impact on climate change through electrification as one of their top three outcomes.

In fact, the majority (64 percent) of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero – and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them with advisory services.

2. Plan Alignment

Toronto Hydro's growth-related investments in the 2025-2029 Capital Expenditure Plan are aligned with customers' expectations to proactively invest in system capacity infrastructure in high growth areas to ensure there is sufficient capacity to maintain current service levels. As discussed in detail in Section D4 – Capacity Planning, Growth and Electrification, when it comes to system capacity, the utility is balancing the need to invest proactively in expanding the system to serve the future needs of its customers with the practical reality that there is uncertainty surrounding the pace of the transition due to policy, technology and consumer behavior factors. Toronto Hydro adopted a "least regrets" planning approach to anticipate and minimize regretful outcomes in the light of this uncertainty.

To facilitate this approach, the utility enhanced its System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth. Toronto Hydro also augmented its decision-making process with the results of a long-term scenario modelling tool known as Future Energy Scenarios, which projects what demand would be under various policy, technology and consumer behaviour assumptions that are linked to Net Zero 2040 or 2050 objectives. The Future Energy Scenarios is described in more detail in Exhibit 2B, Section D4, Appendix A.

The resulting growth-related investments are described in Section 2.4.1 and include the connection of load and generation customers,[17] the accommodation of third-party relocations,[18] capacity

[17] Exhibit 2B, Section E5.1.
[18] Exhibit 2B, Section E5.2.

expansion,[19] and non-wires solutions.[20] Note that Toronto Hydro's "least regrets" investment approach is further reinforced by the utility's Grid Modernization strategy outlined in Exhibit 2B, Section D5. The Grid Modernization Strategy recognizes the need to prepare for coming transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

As part of this strategy, Toronto Hydro is investing in developing a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into utility operations, provide enhanced capabilities to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid, including at the neighbourhood level, where consumer technologies such as electric vehicles are expected to increasingly drive the need for low-voltage system expansions on a more rapid timescale.

E2.3.2 Phase 2 Customer Engagement

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on the following:

- pacing and bill impacts for key investments areas in Toronto Hydro's plan;
- the price of the overall draft plan and whether customers are willing to accept it.

In an effort to be more transparent about the plan, its investments priorities, and outcomes including the price impacts, Toronto Hydro put its entire draft plan to customers. To help customers

[19] *Supra* note 15.
[20] Exhibit 2B, Section E7.2.

understand the investment priorities and provide feedback in terms of trade-offs between price and pacing towards outcomes, Toronto Hydro broke down the draft plan into seven key choices:

1. **Modernization**: Investments to build a smarter, more efficient and resilient grid for the future.[21]
2. **Growth**: Investment to increase the grid's capacity to reliably serve customers growing electricity needs.
3. **Sustainment**: Investments to manage reliability risk due to equipment failure.
4. **Sustainment:** Investments in the paced upkeep of equipment at or near end of life.
5. **Sustainment**: Investments to standardize outdated equipment.
6. **General Plant**: Investments in fleet, facilities and IT infrastructure to keep the business running efficiently.
7. **Decarbonization**: Investments to reduce greenhouse gas emissions from Toronto Hydro's operations by electrifying fleet and facilities assets.

E2.3.2.1 Phase 2 Results

For each of these options, Toronto Hydro put forward the draft plan, along with the options to spend more or less for faster or slower progress towards key outcomes such as reliability, system health, customer service, efficiency, and environment. The outcomes for each investment option were set out in a table, and the interactive slider allowed customers to dial the draft plan up or down based on their preferences. These options to spend more or less were grounded in the investment options developed and considered throughout the planning process.

After considering and providing feedback on the pacing and prioritization in the seven key areas noted above, customers were asked whether Toronto Hydro should stick with its proposed plan, accelerate spending to improve system outcomes, or scale back the plan. An average of 84 percent of customers, across all rate classes either supported sticking with the plan or spending more to improve system outcomes.

While a majority of customers supported the plan, or one that does even more to improve system outcomes, when asked to make certain trade-offs between price and pacing, customers expressed certain preferences to increase, maintain or reduce the pace of the investment plan. Through this

[21] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

feedback on the investment categories, Toronto Hydro was also able to understand where customers prioritize spending.

Generally, customer preferences in terms of trade-offs between price and progress were in-line with Toronto Hydro draft plan in Modernization, Stewardship and Standardization, and slightly lower than the draft plan on Growth, Reliability and General Plant (including Running the Business and Decarbonization). Toronto Hydro used this feedback, along with other information obtained in the normal course of the planning process, to refine and finalize the Plan.

E2.3.2.2 Final Plan Adjustments

Toronto Hydro concluded from the Phase 2 Customer Engagement process that the draft plan achieved an appropriate balance between keeping prices reasonable and delivering the outcomes that customers need and prioritize. In addition, Toronto Hydro used the Phase 2 results to inform the finalization of the plan, making some adjustments where appropriate to reflect customer preferences. Overall, these customer-feedback driven adjustments yielded a further top-down constraint on the plan of approximately $70 million, as summarized in section E2.1.3 above.

E2.4 Portfolio Planning for 2025-2029

Toronto Hydro's Portfolio Planning process used the outputs of the Asset Needs Assessment to develop program-level expenditure plan proposals that would support the utility's asset management outcome objectives for 2025-2029.

As described in Section D3.4.3, Toronto Hydro developed bottom-up expenditure plan scenarios for each capital program, leveraging the asset lifecycle optimization and risk management practices and methodologies described in Section D3. The proposals were evaluated in relation to their potential contribution to: (i) the utility's outcome objectives and measures; and (ii) alignment with customer needs and preferences. The program proposals were further refined as a result of business inputs and information, as well as feedback received in the second phase of Customer Engagement (discussed in Section E2.3 above).

The following subsections describe how the outputs of the Asset Needs Assessment and the utility's asset lifecycle optimization and risk management practices informed the timing and pacing of the programs in the 2025-2029 Capital Expenditure Plan under the focus areas of Growth, Sustainment, Modernization, and General Plant.

E2.4.1 Growth Expenditures

Toronto Hydro developed a 2025-2029 Growth expenditure plan that is responsive to the utility's need to continuously meet its legally mandated service obligations, including the requirement to safely connect load and generation customers in a timely manner, and requirements to comply with revenue metering and billing standards. The pacing of investments in this category was largely dictated by the anticipated projected demand in these areas over the 2025-2029 period. Toronto Hydro considered the expected impacts of increased electrification demands on the grid in the 2025-2029 period and relied on the Peak Demand Forecast to understand growth drivers and the related investment needs.

Table 3: 2025-2029 Growth Expenditure Plan ($ Millions)

Capital Program	Costs ($M)
Customer Connections (Exhibit 2B, Section E5.1)	$477
Externally Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2)	$76
Load Demand (Exhibit 2B, Section E5.3)	$236
Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5)	$35
Non-Wires Alternatives (Exhibit 2B, Section E7.2)	$23
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$965**

E2.4.1.1 Connecting Load Customers

Toronto Hydro's Customer Connections,[22] and Load Demand programs support the safe, timely, and cost-efficient connection of load customers.[23] Forecast expenditures for load connections are based on historical trends in gross cost and customer contribution amounts for load connection activities. They are also informed by development trends in the City[24] and the adoption of emerging technologies catered towards clean energy and electrification. The utility's 2025-2029 expenditure plan anticipates growth in new services, upgrades, and removals based on current and proposed development. (Refer to Section E5.1 for more details.)

[22] *Supra* note 17.
[23] *Supra* note 16.
[24] As described in Exhibit 2B, Section B2.2, Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects.

The Load Demand program addresses near-term system capacity constraints in areas of concentrated load growth. Toronto Hydro's Distribution Capacity and Capability Assessments (summarized in Section D3.3) identified a number of areas in both the Horseshoe and Downtown regions of the system where investments such as load transfers, cable upgrades, and equipment upgrades will likely be required to ensure the utility can continue to connect customers efficiently. These investments are also necessary to maintain sufficient grid flexibility to handle contingency scenarios and optimize planned work schedules, contributing to Toronto Hydro's reliability objectives and improving customer satisfaction by providing large customers with greater scheduling flexibility for planned outages.

Overall, the proposed expenditure plans in these two load-driven Growth programs reflect the investments required to connect customers in accordance with the OEB's service connection targets, while maintaining system performance for existing customers and improving the effects of scheduled outages on the operations of larger customers.

E2.4.1.2 Connecting Generation Customers

Toronto Hydro's Customer Connections,[25] and Generation Protection, Monitoring, and Control programs ("GPMC"),[26] support the safe, timely, and cost-efficient distributed energy resource ("DER") connections to the distribution system, including renewable energy generation ("REG") projects. The utility aligned the planned 2025-2029 expenditures in both programs with its 2023-2029 DER connection and capacity forecasts, illustrated in Figures 2 through 8 in Section E3. These forecasts considered historical connection trends, current pipeline of applications, the economic environment, government and regulatory incentives, and net zero initiatives. The utility currently projects that the total number of DER connections will grow from about 2,700 in 2023 to nearly 4,500 by the end of 2029 – an increase of roughly 67 percent.

Toronto Hydro's Generation Capacity and Capability Assessment (described in Section E3.3) identified a number of challenges to accommodating the forecasted 516.7 MW of DERs on the system by the end of 2029, including short-circuit capacity constraints, islanding risks, and system thermal limits. To address the above challenges and continue to connect all forecasted DERs, Toronto Hydro plans investments in Generation Protection, Monitoring, and Control,[27] and Energy Storage

[25] *Supra* note 17.
[26] Exhibit 2B, Section E5.5.
[27] *Ibid*.

Systems (Non-Wires Solutions Program).[28] Through the GPMC program, the utility aims to install six bus-tie reactors to address short-circuit capacity constraints and 315 monitoring and control systems to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. Through the Energy Storage Systems ("ESS"), Toronto Hydro intends to develop a scalable, demand-driven, ESS strategy that enables renewable integration. ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio. Toronto Hydro plans to deploy nine renewable-enabling ESS projects

E2.4.1.3 Accommodating Third-Party Plant Relocation Requests

The Externally Initiated Plan Relocations and Expansions program funds plant relocations and expansions triggered by third-party requests.[29] In accordance with OEB's Distribution System Code ("DSC") and related legislation (i.e. *Building Transit Faster Act, 2020* and *Public Works and Highways Act, 1998)*, Toronto Hydro is legally obligated to work cooperatively with third parties towards accommodating these requests in a fair and reasonable manner.[30][31] For the 2025-2029 period, the utility developed an expenditure plan to address committed relocation and expansion projects from third-parties, including Road Authorities (e.g. the City of Toronto), Metrolinx, and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications.[32] These capital plans and project schedules are subject to change at the discretion of the sponsor agencies, and any such changes typically impact the timing and potential the scope of Toronto Hydro's relocation and expansion work.

E2.4.1.4 Capacity Expansion and Demand Response

Whereas Toronto Hydro's Load Demand investments are driven by the short-term capacity needs of the system, its Stations Expansions investments are driven by long-term capacity needs of the system to renew and expand its stations. The utility's investment plans are informed by its Station Load Forecast (for more details see Section D4), the Regional Planning process, and are aligned with Hydro

[28] *Supra* note 20.
[29] *Supra* note 18.
[30] The Distribution System Code, (August 2, 2023), Section 3.1.10.
[31] *Building Transit Faster Act ("BTFA"), 2020*, S.O. 2020, c. 12 and *Public Works and Highways Act, 1998*, RSO 1990, Ch P.49.
[32] Exhibit 2B, Section B - Coordinated Planning

One's sustainment plans. Given the complexity and size of these individual projects, their expenditures are discrete and not conducive to smoothing over the rate period.

Investments for the 2025-2029 period are driven by anticipated bus-level constraints for stations serving areas of high growth and development, and are fully aligned with the results of regional planning activities conducted in coordination with the Independent Electricity System Operator ("IESO") and Hydro One.[33] The most recent planning document from this process is the Needs Assessment Report for the Toronto Region. Refer to Section B for more information on coordinated system planning with third parties. The proposed projects will add or free up 574 MVA capacity, supporting the sustainment of reliability, operational flexibility, and connections capabilities.

E2.4.2 Sustainment Expenditures

Continued proactive renewal expenditures are required during the 2025-2029 period to manage significant safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers.[34] As described in Section E2.2.1.1. above, approximately one quarter of Toronto Hydro's assets are operating beyond useful life. The system continues to age at a rate comparable to the projected rate of aging in recent rate periods, although a slight increase is expected in the assets at end-of-life by 2030. Condition demographic results continue to indicate substantial asset investment needs for a number of asset classes, and the utility continues to face challenges related to higher-risk, obsolete legacy assets and asset configurations such as rear lot plant and direct-buried cable.

The first phase of Customer Engagement revealed that most low-volume and medium-sized customers were satisfied with average reliability performance while larger users indicated a greater interest in reliability and reduction in restoration times. In light of these results, and leveraging the asset risk assessment and mitigation practices discussed in Section D3, Toronto Hydro developed program expenditure plans for 2025-2029 that ensure the minimum pace necessary to sustain overall asset risk and reliability performance at current levels, while also driving targeted outcome improvements. These outcome improvements include, reducing the risk of PCB contaminated oil spills, reducing the level of failure risk related to a significant backlog of aging and poor condition stations assets, and improving performance on worst performing feeders.

[33] It is also important to note that these investments are aligned with Hydro One's sustainment plans.
[34] See detailed description in Overview of Distribution Assets (Section D2) and in the System Renewal programs (Section E6).

Table 4: 2025-2029 Sustainment Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
Area Conversions (Exhibit 2B, Section E6.1)	$237
Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)	$476
Underground Renewal – Downtown (Exhibit 2B, Section E6.3)	$165
Network System Renewal (Exhibit 2B, Section E6.4)	$123
Overhead Renewal (Exhibit 2B, Section E6.5)	$273
Stations Renewal (Exhibit 2B, Section E6.6)	$218
Reactive and Corrective Capital (Exhibit 2B, Section E6.7)	$328
Sustainment Capital	**$1,820**

E2.4.2.1 Overhead Asset Renewal Investments

Toronto Hydro's Overhead System Renewal,[35] Area Conversions,[36] and Reactive and Corrective Capital programs address failure and obsolescence risks related to overhead grid system assets.[37] The utility paced the 2025-2029 expenditure plan for these programs to: (i) maintain current system reliability performance; (ii) prevent age and condition related asset risk from accumulating over the period; and (iii) continue to reduce and eliminate safety and environmental risks and other deficiencies associated with legacy assets and asset configurations.

Demographic pressure on wood poles and pole top transformers is the key driver of overhead renewal need during the 2025-2029 period is.[38] Wood poles are critical to the safety and viability of the distribution system.[39] About 9,000 poles, or ten percent of Toronto Hydro's wood pole population, currently show at least material deterioration (i.e. HI4). The utility projects the total number of poles at material deterioration or worse condition could more than triple to an estimated 32,000 by 2030 without intervention (including an increase in poles at "end-of-serviceable life" from approximately 500 to over 7,000). Toronto Hydro's 2025-2029 expenditure plan will manage failure risk by prioritizing replacement of poles near or at "end-of-serviceable life" condition (i.e. HI5). The

[35] Exhibit 2B, Section E6.5.
[36] Exhibit 2B, Section E6.1.
[37] Exhibit 2B, Section E6.7.
[38] See section D2.1.1.
[39] Wood pole replacement is the highest-volume renewal activity out of the subset of assets that are analyzed through Toronto Hydro's ACA methodology. Given the importance of managing the overall condition-informed failure risk for this asset class over the planning period, the utility began tracking the wood pole condition demographics as a Custom Performance Measure starting in 2020 (see Section C for more details).

Overhead System Renewal program budgets for approximately 12,000 pole replacements from 2023 to 2029. In addition, the Area Conversions,[40] and the Reactive Capital programs will also include pole replacements.[41]

The percentage of pole-top transformer units operating beyond their 45-year useful life is projected to increase from 24 percent to 30 percent by the end of 2029. Compounding the reliability dimension of this risk is potential for oils spills, including spills containing PCBs, from pole-top transformer failure. The utility has paced pole-top transformer replacement to align with reliability objectives and to work towards eliminating the risk of PCB contaminated oil spills by 2025.

Figure 7: Rusted Overhead Transformers at Risk of Leaking Oil

The Area Conversions program addresses the obsolete, legacy overhead construction types which are an ongoing challenge for Toronto Hydro, including rear lot construction and box construction. Because of the continuing decline in rear lot plant performance, and the high complexity and duration of rear lot conversion projects, Toronto Hydro determined it is necessary to continue removing rear lot plant proactively at a steady pace, prioritizing areas where customers are experiencing the worst performance. For box construction, Toronto Hydro developed a plan for 2025-2029 that continues the strategy of eliminating all box construction poles by 2026, as first articulated in the 2015-2019 DSP. This is the fastest executable rate at which the utility can eliminate this legacy configuration.

[40] *Supra* note 36.
[40] *Ibid*.
[41] *Supra* note 37.

Figure 8: Box Construction (left). Replacing a transformer on a poor condition Rear Lot pole (right)

E2.4.2.2 Underground Asset Renewal Investments

Failure and obsolescence risks related to underground system assets are addressed by Toronto Hydro's Underground System Renewal – Horseshoe,[42] Underground System Renewal – Downtown,[43] Area Conversions,[44] and Reactive and Corrective Capital programs.[45] As with the overhead asset renewal investments, the 2025-2029 expenditure plan for these programs is paced to maintain system reliability, prevent age and condition related risk from accumulating and reduce and eliminate safety and environmental risks.

Legacy asset performance and risks – particularly the reliability-related failure risks associated with obsolete cables (i.e. direct buried and lead) – continue to be the most significant driver of renewal needs on the underground system. Underground cables have been the single greatest contributor to outages caused by defective equipment, resulting on average in 146,000 customer hours of interruption annually.

The utility's Asset Needs Assessment identified 666 circuit-kilometres of direct-buried cable and direct-buried cable in duct remaining in the Horseshoe area as of 2022. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type. Approximately 61 percent of this cable is currently beyond its useful life and the utility anticipates that 64 percent will be at or beyond useful life by end of 2029. To prevent reliability from degrading, the utility developed

[42] Exhibit 2B, Section E6.2.
[43] Exhibit 2B, Section E6.3.
[44] *Supra* note 36.
[45] *Supra* note 37.

a plan to proactively replace an estimated 182 circuit-kilometres of this cable in the Underground System Renewal – Horseshoe program during the 2025-2029 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure.[46]

Toronto Hydro's Asset Needs Assessment also resulted in the continuation of a long-term renewal strategy for lead cable in the downtown area. Due to the generally good reliability performance of lead-covered cable, Toronto Hydro has historically managed these assets through reactive and corrective interventions and targeted repairs. However, these cable types have shown signs of aging and declining performance in recent years and are largely considered obsolete in North America due to various safety and environmental risks (see Section E6.3 for more details).[47]

Figure 9: Collapsed cable splice

To manage the significant magnitude of this asset renewal need, Toronto Hydro developed a prioritization model to rank primary feeder cable segments in the system using factors such as historical failures, cable types, number of splices, age and customer base.[48] Based on this prioritization model, Toronto Hydro developed a plan to maintain reliability performance for affected customers by replacing approximately 3.5 percent of the 985 kilometres of paper-insulated lead-covered ("PILC") and 5.2 percent of the 176 kilometres of asbestos-insulated lead-covered PILC cable with modern polymeric cables in the 2025-2029 period.

[46] Given its significant impact on reliability and the fact that this is the utility's largest renewal activity, Toronto Hydro plans to continue reporting its progress on this plan as a 2025-2029 Custom Performance Measure under the Reliability outcome category (see Section C).
[47] There is only one supplier of paper-insulated lead-covered ("PILC") cable remaining in North America and no suppliers of asbestos-insulated lead-covered ("AILC") cable.
[48] The results of this analysis are summarized in Exhibit 2B, Section E6.3, Figures 1 and 2.

Other electrical assets addressed by the Underground System Renewal programs include transformers and switches in the Horseshoe area and on the Underground Residential Distribution ("URD") system, which serves low-volume customers in parts of the downtown area. These assets will be prioritized based on age, condition and historical performance and will largely be addressed in conjunction with underground cable rebuild projects and voltage conversion, except on the URD system and in cases where submersible, pad-mount and vault transformers must be replaced on a spot basis by 2025 to reduce risks of PCB contaminated oil spills.

Figure 10: Corrosion on top of a Submersible Transformer

The Underground System Renewal – Downtown program also continues a proactive cable chamber renewal plan. Managing the condition-related risk of failure of cable chambers is essential to ensuring the safety and long-term viability of the underground system. Toronto Hydro has historically managed these civil assets reactively, however, the latest Asset Needs Assessment identified a significant population of cable chambers with at least material deterioration. There are currently 130 cable chambers currently in "end-of-serviceable life" condition (HI5) and 462 in material deterioration condition (HI4). Toronto Hydro developed a plan to proactively help prevent condition demographics from deteriorating further over the 2025-2029 period by rebuilding approximately 45 cable chambers, replacing approximately 2,800 cable chamber lids, rebuilding over 120 cable chamber roofs and addressing an estimated 25 cable chambers that need to be abandoned.

Figure 11: Cable Chamber roof in HI5 condition (left), Cable chamber roof inside view (right)

Starting in 2025, Toronto Hydro is introducing a planned renewal segment to address underground switchgear in customer-owned vaults that feed apartment buildings, educational facilities and community centres. Previously Toronto Hydro managed the replacement of these assets on a reactive basis, however, these require replacement due to obsolescence. Toronto Hydro plans to target the worst condition and most critical assets to maintain average reliability performance for customers served by these assets.

E2.4.2.3 Network Asset Renewal Investments

Failure and obsolescence risks related to network system assets are addressed by Toronto Hydro's Network System Renewal,[49] and Reactive and Corrective Capital programs.[50] The utility paced the 2025-2029 expenditure plans for these programs to: i) maintain current system reliability performance; ii) improve resiliency and operational efficiency of the network; iii) prevent age, condition and obsolescence related asset risk from accumulating over the period; and iv) continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

The network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive customers in the City's core, which contains dense, high-traffic commercial and residential areas. The network system is designed to handle normal failure scenarios better than Toronto Hydro's other system configurations.[51] However, in the case of catastrophic failures such as a vault fire, the entire secondary network grid that is connected to the vault must be de-energized until the situation can be safely remedied, which can take over 24 hours. These types of failures can

[49] Exhibit 2B, Section E6.4.
[50] *Supra* note 37.
[51] Exhibit 2B, Section D2.2.3.

result in risks to public safety and the environment. To minimize these scenarios, Toronto Hydro takes a highly proactive approach to network equipment and vault maintenance and renewal.

Figure 12: Damage from a network vault fire

The risk of flooding continues to be a concern on the network system. As noted in Section D2.1.2, four of the 10 highest rainfall years on record have occurred in the last decade. Toronto Hydro developed a plan for the 2025-2029 period that targets non-submersible network units which are susceptible to water ingress and have elevated failure risks even when in good condition. There are currently 43 network transformers with material deterioration. Condition projections suggest that 149 units will be in HI4 and HI5 condition by 2029 without intervention. Age projections indicate that 50 percent of the system's network units will be at or beyond useful life by 2034. Toronto Hydro is planning to replace 95 units in 2023-2024 and 130 units in 2025-2029. This pace of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population.

To mitigate risks to public and employee safety, the utility also plans to continue proactively renewing network vaults in poor condition. The number of vaults in HI4 and HI5 condition is expected to grow from 91 to over 130 by 2030 without intervention, which would represent 29 percent of the population. The utility is planning to proactively address 38 vaults over the 2025-2029 period. Network vault rebuilds are complex projects in congested areas and require significant planning efforts, making it necessary for the utility to maintain a steady and proactive renewal program over time.

Toronto Hydro plans to reconfigure three networks over the 2025-2029 period as part of its Network Circuit Reconfiguration segment (under Network System Renewal program).[52] This segment involves

[52] *Supra* note 49.

reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. These reconfigurations will help improve outage restoration time and reduce risks associated with second contingency events for downtown network customers.

E2.4.2.4 Stations Renewal Investments

Toronto Hydro's Stations Renewal,[53] and Reactive and Corrective Capital programs address failure and obsolescence risks related to stations assets.[54] Stations assets are highly critical assets that have the potential for causing widespread and lengthy interruptions in the event of failure.[55] Stations asset replacement projects are complex and typically require long lead and execution timelines. In light of these operational constraints and a growing backlog of stations renewal needs, Toronto Hydro developed a plan for the 2025-2029 period that addresses stations equipment at a faster pace than in the 2020-2024 period. This is needed to maintain station asset demographics, as well as to replace obsolete station electromechanical relays with modern digital relays – an important part of Toronto Hydro's Intelligent Grid strategy as discussed in the Grid Modernization Strategy in Section D5.

The Asset Needs Assessment for stations assets continues to identify a significant backlog of aging equipment, with 42 percent of switchgear, 51 percent of power transformers, 48 percent of outdoor breakers, and 55 percent of DC battery systems operating at or beyond their useful life. The need for investment was further underscored by the high proportion of assets in moderate (H3), material (HI4), and end-of-serviceable-life (HI5) condition, as shown in Figure 13 below.

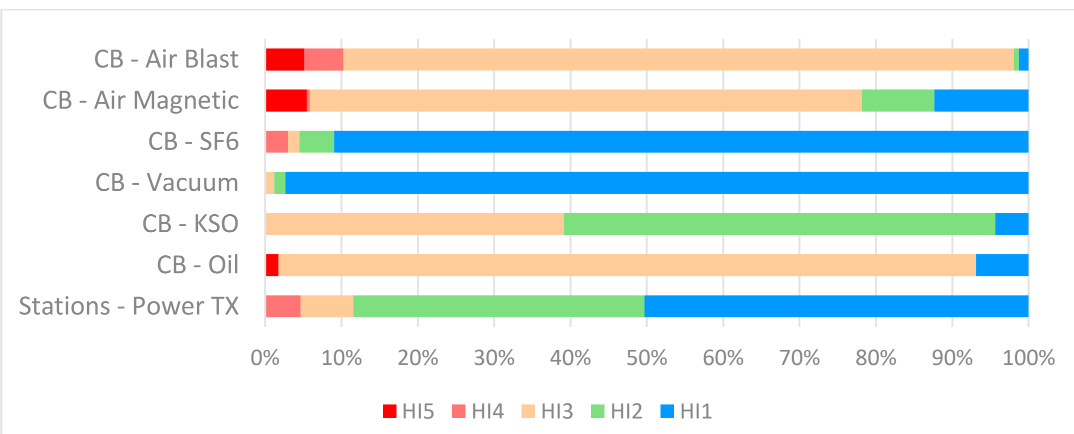


Figure 13: Asset Condition Assessment of Station Assets

[53] Exhibit 2B, Section E6.6.
[54] *Supra* note 37.
[55] *Supra* note 53.

Overall, in support of its objectives to maintain reliability, improve system resiliency, and manage the long-term viability of the distribution system, Toronto Hydro developed plans to execute the following stations work in the 2025-2029 period:

- Replace three TS switchgear units –serving the highest-density areas of Toronto – all of which are beyond their 50-year useful life and feature obsolete circuit breaker designs contained within non-arc resistant enclosures (elevating safety risks for employees);
- Replace 12 TS outdoor circuit breakers prioritized based on condition, age, load served, and at risk of containing PCB;
- Replace 63 TS outdoor switches that are beyond their 50-year useful life, reducing the risk of lengthy interruptions for customers in the North York area of Toronto;
- Remove 12 aging and deteriorating Municipal Station ("MS") switchgear with obsolete circuit breakers;
- Replace 15 power transformers, to mitigate an increased failure rate in this rate period and the next. All power transformers will be between 54 and 66 years of age at the time of replacement and have identified condition concerns such as high-power factor and low insulation resistance;
- Replace 1 end-of-life MS primary supply, which has assets older than 60 years of age at the time of replacement; and
- Renew end-of-life stations battery and ancillary systems.

E2.4.2.5 PCB Risk Reduction Strategy

Toronto Hydro's risk mitigation strategy for PCB contaminated oil spills is a key driver and prioritization consideration for multiple renewal programs. Due to the toxic and persistent nature of PCB, the Government of Canada's PCB Regulations[56] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.

Toronto Hydro is continuing its efforts to eliminate the risk of oil spills containing PCBs on its overhead, underground, and network systems by 2025 through inspection and testing under its

[56] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act, 1999.*

maintenance programs (discussed in Exhibit 4, Tab 2, Schedules 1-4) and through targeted asset replacement as set out in the programs described above.[57]

E2.4.3 Modernization Program Expenditures

Toronto Hydro developed a 2025-2029 Modernization expenditure plan that targets a select number of system enhancement needs that support the utility's asset management objectives for the period and deliver customer value using technology-driven solutions. Toronto Hydro's modernization investments are aligned with its 2025-2029 Grid Modernization Strategy, discussed in Section D5. This strategy is driven by a confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. Distributed Energy Resources) – which threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. The Grid Modernization Strategy addresses these emerging challenges and parallel opportunities in a paced manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. Complementing this focus on proven technology is a secondary emphasis on innovation. There are certain challenges – e.g. cost-effectively increasing the amount of distributed generation that can connect to congested feeders – for which the optimal technological and commercial solutions are not yet settled or mature. In these areas, Toronto Hydro is planning to increase its investment in pilot projects and industry partnerships, which the utility believes can contribute to accelerated progress across the entire sector. For a comprehensive overview of the core elements of the Grid Modernization Strategy, refer to Section D5.

Table 5: 2025-2029 Modernization Expenditure Plan ($ Millions)

Capital Program/Segment	Costs ($M)
System Enhancement (Exhibit 2B, Section E7.1)	$151
Network Condition Monitoring and Control (Exhibit 2B, Section E7.3)	$6
Metering (Exhibit 2B, Section E5.4)	$248
Overhead Resiliency (Exhibit 2B, Section E6.5)	$86

[57] Overhead System Renewal (*Supra* note 35.), Underground System Renewal (*Supra* note 42 and 43), Stations Renewal (*Supra* note 52), and Reactive and Corrective Capital (Exhibit 2B, Section E6.7). Refer to each of these programs for a description of how the planned investments address PCB at-risk equipment and potential challenges.

Capital Program/Segment	Costs ($M)
Stations Control and Monitoring (Exhibit 2B, Section E6.6)	$65
IT Cyber Security & Software Enhancements (Exhibit 2B, Section E8.4) [58]	$94
Modernization Capital	**$651**

E2.4.3.1 Metering Investments

Investments in the Metering program (Section E5.4) are triggered by the need to remain in compliance with OEB's minimum standards for billing accuracy and Measurement Canada and IESO requirements related to metering and billing. Based on a needs assessment for its metering assets, Toronto Hydro developed a plan for 2025-2029 that is largely driven by the timing of metering and metering system upgrade cycles. Residential and Small Business (C&I) Meter Replacement activities will continue in order to address end-of-life meters with expiring seals. Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. Through these replacements, Toronto Hydro plans to install next generation smart meters (referred to as Advanced Metering Infrastructure 2.0 or AMI 2.0) and upgrade the supporting metering infrastructure. AMI 2.0 will play an important role in establishing a greater level of system observability within Toronto Hydro's Grid Modernization Strategy. For more information on expected use cases for AMI 2.0, please refer to Section D5.2.2 and D5.3.1.

E2.4.3.2 System Design Enhancements and Modernization

Through the Asset Needs Assessment and the Portfolio Planning process, as well as the parallel Grid Modernization Strategy development exercise, Toronto Hydro identified several targeted opportunities to address asset risk and enhance customer value by improving system design and investing in system modernization. The bulk of this planned investment is in the System Enhancements (Section E7.1) and Network Condition Monitoring and Control (Section E7.3) programs. These programs will continue Toronto Hydro's efforts to identify places on the system where asset failure risk can be mitigated, outage restoration capabilities improved, and future operational costs reduced through the installation of protection devices and remote SCADA-enabled switches and sensors.

[58] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

The Network Condition Monitoring and Control program was introduced for 2020-2024 and arose out of the need to address performance risks and connection capability challenges on the network system. These issues risk eroding the long-term viability of the network at a time when its compact and reliable design is becoming an increasingly effective option for medium and large customers in developing, high-density areas of the City. Toronto Hydro expects to continue its original objectives of the program to install monitoring and control equipment and fibre optic cable in approximately 920 network vaults by the end of 2026. This will complete Toronto Hydro's first major implementation of an entirely new set of distributed smart grid capabilities since the initial roll-out of AMI. Organizational learnings from this program, including the successful achievement of reliability, and cost reduction and avoidance benefits, will be applied to the implementation of Toronto Hydro's 2025-2029 Grid Modernisation Strategy. Pilot projects to further enhance network monitoring capabilities, such as the installation of fire sensors, analog water sensor, a vault camera, vault hatch open sensor, and secondary cable monitoring with cable sensors will commence after 2025. These improvements will enhance Toronto Hydro's ability to detect emergencies earlier and prevent catastrophic accidents from occurring.

Over the 2025-2029 period, the System Enhancements program is comprised of three investment initiatives that will strategically address critical issues like operational constraints, security-of-supply risks and system operational inefficiencies. The Contingency Enhancement segment will continue to enhance Toronto Hydro's ability to efficiently restore power to customers in the Horseshoe and Downtown areas. By installing 205 new SCADA switches in the Horseshoe, this segment will ensure that at least 90 percent of Horseshoe feeders have the minimum infrastructure (SCADA switches and reclosers) in place to integrate into a "self-healing" network beginning in 2030. It will deploy a total of 298 switches and 220 reclosers more broadly on parts of the system that can benefit materially from improved outage restoration and protections, contributing to Toronto Hydro's objective of improving SAIDI generally, as well as improving reliability for customers on poor performing feeders over the 2025-2029 period, and ensuring the system has appropriate flexibility to maintain reliability and operate efficiently over the long-term in the face of demand growth and potential DER proliferation. The Downtown Contingency segment allows for N-2 (i.e. two station loss-of-supply issues at the same time) operational capability to address serious, high-impact loss-of-supply scenarios for areas of the city with critical institutional and economically significant loads. Copeland Station is the optimal downtown anchor source, and for the 2025-29 period, eligible stations with 3000A feeder positions will receive station-to-station switchgear ties. Lastly, in accordance with Toronto Hydro's grid modernization goals, the System Observability segment will introduce new equipment that improves reliability and system awareness of the distribution system, contributing to improved operational efficiency, outage response, asset management decision-making, and load and generation forecasting. This will be achieved through the targeted deployment of sensors (such as overhead and underground sensors, online cable monitoring, and transformer monitoring) that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid.

In addition to the System Enhancements and the NCMC programs, Toronto Hydro plans to renew and modernize protection, control, monitoring, and communication assets at its Transformer and Municipal Stations. Replacing these deteriorated and obsolete assets enables the utility to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 period, Toronto Hydro plans to renew 33 existing Remote Terminal Units (RTUs) and replace 251 obsolete relays with modern digital relays.

E2.4.3.3 System Resiliency

Over the 2025-2029 period, Toronto Hydro is reintroducing and expanding the work done through the 2015-2019 Overhead Infrastructure Relocation program[59] to improve the resiliency of the overhead system through targeted relocations and/or undergrounding of overhead assets that are vulnerable to power outages during major storm events. Specifically, Toronto Hydro seeks to (i) underground critical sections of overhead infrastructure that are persistently affected by outages caused by external factors; (ii) relocate overhead sections in areas with limited access; and (iii) reconfigure and, if necessary, underground pole lines exiting stations that carry three or more circuits.

By increasing the resiliency of the system, these investments will reduce the impact of outages due to weather events on customers, and as such are responsive to customer reliability priorities as described in Section E2.3.1.2.

E2.4.3.4 IT Software Enhancements

Modernization efforts with respect to the grid and business operations are supported by various IT software investments during the 2025-2029 period, which includes the Advanced Distribution Management System ("ADMS"). For example, while the System Enhancement program deploys SCADA switches on the distribution network, which are critical for distribution automation, IT

[59] EB-2014-0116, Exhibit 2B, Section E6.5

initiatives, such as the implementation of manual Fault Location, Isolation and Service Restoration (FLISR) technology (as part of the broader ADMS project) in 2025-2029, will apply real-time analytics to the operation of these switches to support further reductions in fault isolation and service restoration duration. These investments are also foundational to Toronto Hydro's goal of preparing the Horseshoe grid for the implementation of a fully automated, self-healing grid operation beginning in 2030. More broadly, Toronto Hydro intends to accelerate investment in data quality and governance, system integrations, data analytics, process automation, customer facing tools, and decision-making platforms in 2025-2029 to enhance value for customers and establish the foundations and capabilities for longer-term efficiency and sustainable performance. For more information on enhancements, refer to the Grid Modernization Strategy in Section D5 and the IT Investment Strategy in Section D8.

Over the 2025-2029 period and as part of its broader Modernization efforts, Toronto Hydro also plans to continue to invest in cybersecurity controls to monitor digital threats and ensure a robust response to intensifying risks in this area. The investment plans were developed such that the utility is able to maintain its cybersecurity posture at current levels while developing future state readiness to adapt to the constantly changing cybersecurity threat landscape.

E2.4.4 General Plant Expenditures

Toronto Hydro developed a General Plant expenditure plan leveraging the asset management principles and strategies outlined in Sections D6 ("Facilities Asset Management"), D8 ("IT Asset Management"), and Section E8.3 ("Fleet and Equipment Services"). This plan also supports Toronto Hydro's Net Zero 2040 strategy as set out in Section D7 ("Net Zero 2040"). Investments in this category are necessary to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs, and emerging customer needs and preferences.

Table 6: 2025-2029 General Plant Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
Enterprise Data Centre (Exhibit 2B, Section E8.1)	$72
Facilities Management and Security (Exhibit 2B, Section E8.2)	$145
Fleet and Equipment Services (Exhibit 2B, Section E8.3)	$44

Capital Program/Segment	Costs
Information and Operational Technology (Exhibit 2B, Section E8.4)[60]	$206
General Plant Capital	**$467**

E2.4.4.1 Fleet and Facilities

Investments in Facilities Management and Security,[61] and Fleet and Equipment needs are primarily driven by asset obsolescence, condition and lifecycle cost analysis for major work centres, stations buildings, physical security systems, and vehicles.[62]

Investments are also driven by the decarbonization goals set out in the utility's Net Zero 2040 strategy (Section D6). In order to meet these goals, the utility plans to electrify fleet and facilities assets. Specifically, Toronto Hydro intends to reduce emissions from its vehicles and work centres by: (i) replacing gasoline and diesel power vehicles with hybrid and electric vehicles, and (ii) converting natural gas boilers and heaters in the work centres to electric boilers and heaters.

E2.4.4.2 Information and Operational Technology (IT/OT)

The utility's planned IT/OT Systems investments[63] for the 2025-2029 period are primarily directed at maintaining current business capabilities, with the remainder directed at expanding existing business capabilities or driving new ones in alignment with outcome objectives and customer needs. The IT/OT program consists of the following key elements:

- **IT Hardware:** Planned expenditure levels were developed to align with asset lifecycles for backend assets (e.g. servers) and endpoint assets (e.g. laptops) that require replacement, and to meet anticipated business needs as forecasted through business planning.
- **IT Software:** Planned expenditure levels were developed in anticipation of upgrade requirements (i.e. security patches, version upgrades to secure vendor support, etc.) for major IT systems such as the utility's Enterprise Resource Planning ("ERP") and other minor applications. Expenditures also include regulatory compliance needs and a portion of software enhancements to improve and expand business functionality.

[60] *Supra.* note 58.
[61] Exhibit 2B, Section E8.2.
[62] Exhibit 2B, Section E8.3.
[63] Exhibit 2B, Section E8.4.

- **Communication Infrastructure:** Planned expenditure levels were developed to address communications infrastructure that is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. Proposed investments will address functional obsolescence and reliability risk (e.g. upgrading the communications technology that supports the utility's critical SCADA system), safety and operational risks (i.e. underground radio expansion) and support for system modernization investments (e.g. fibre-optic plant replacement and expansion to support Network Condition Monitoring and Control).

To inform the level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting (see Section D8, Appendix A), which concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers and the increase in Toronto Hydro's 2022 IT spending compared to 2017 is similar to industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending ([…] largely due to the Customer Information System ("CIS") upgrade) and IT Management and Administration ([…] largely due to increased investment in Cyber Security services)."

E2.4.4.3 Enterprise Data Centre

Toronto Hydro's operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems and server infrastructure across two distinct locations that collectively support organization-wide ("enterprise") processes. Toronto Hydro will need to store more data within its EDCs as the utility continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, DER owners and operators, and other stakeholders, and as the utility modernizes its systems and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period.

Although Toronto Hydro has prudently managed and maintained reliability and operational resilience at its EDC locations through its robust asset management strategy and asset renewal and repair activities,[64] the utility expects that EDC 1 will reach its capacity within the next five years and

[64] Exhibit 2B, Sections D6 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 12 (Facilities Management OM&A program).

will no longer be able to accommodate new data and support new systems. As such, Toronto Hydro proposes to relocate EDC 1 to another centre to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage.

E2.4.4.4 Portfolio Reporting

The Portfolio Reporting element of IPPR directly informed the development of capital program expenditure plans for the 2025-2029 period. In particular, Toronto Hydro analyzed actual project accomplishments and costs in each program to establish the project- and/or volume-based assumptions that would form the basis of the high-level program cost estimates for the 2025-2029 period.[65] Due to the unique nature of work in each capital program (e.g. large discrete assets vs. area rebuilds; like-for-like vs. reconfiguration), Toronto Hydro's planners relied on different estimating approaches for different programs, leveraging both historical information and professional judgement. These assumptions were challenged and refined throughout the IPPR process and business planning.

E2.4.4.5 Capital Program Efficiency and Unit Cost Benchmarking

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2020-2022 period. UMS performed a normalized comparison of these results to those of peer utilities across North America.

Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, procurement, and execution practices. UMS also noted that if certain qualitative considerations, such as customer density, were statistically normalized for, Toronto Hydro's comparative ranking would be better than shown. The study can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix C.

[65] For many DSP programs, it is practically infeasible to develop project-specific details for a five- to seven-year planning horizon. Planners used a mix of analogous and parametric estimating techniques to create high-level estimates for the programs in these situations. Analogous estimating involves creating a "top-down" estimate of a project's cost and duration using experience with similar projects. Parametric estimating involves identifying volumetric costs and scaling the project or program estimate by the volume of units.

E3 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

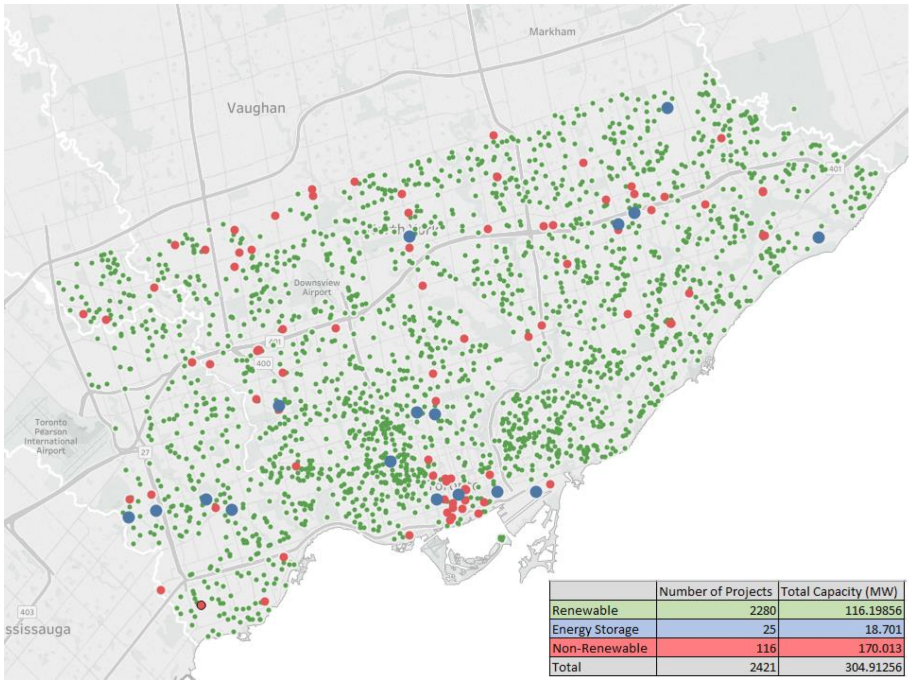
This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation and other distributed energy resource ("DER") connections. This information includes renewable DER applications, overall DER connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 DER Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro connected over 2400 DERs under various programs including FIT, HCI, PSUI-CDM, RESOP, HESOP,[1] and Net-Metering. In 2018, the FIT and micro FIT programs ended, and the *Green Energy and Green Economy Act, 2009* was repealed on January 1, 2019. Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Toronto Hydro continues to receive applications from a wide range of proponents including, but not limited to, individual residential addresses, public transit facilities, housing developments, large grocery stores, educational facilities, and hospitals.

As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid. Figure 1 provides an overview of existing DER connections within Toronto Hydro's service territory. This represents over 304.9 MW of generation capacity across various types of DER technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");



	Number of Projects	Total Capacity (MW)
Renewable	2280	116.19856
Energy Storage	25	18.701
Non-Renewable	116	170.013
Total	2421	304.91256

Figure 1: Toronto Hydro DG Connections (as of December 31st, 2022)

From 2018 to 2022, Toronto Hydro connected about 93.2 MW of generation to its distribution system, which represents approximately 22.8 percent of the 408.4 MW connected capacity that was projected for the same time period in the 2020-2024 rate application. The lower than expected DER capacity connected during this period can be attributed to various reasons:

- The conclusion of the FIT program in 2018 led to a greater than anticipated decrease with a 71.9 percent decline in renewable DER pre-assessment applications in the years immediately following the cancellation across residential, commercial & industrial segments.
- Changes in the IESO Process Systems & Upgrade program in 2019 made fossil-fuel based CHP projects ineligible for incentives.
- During the COVID-19 pandemic there was a sharp reduction in applications for pre-assessments for DERs by commercial and industrial businesses. Subsequently, connections fell well below pre-pandemic expectations.
- A number of large projects were placed on hold indefinitely by customers or were cancelled, including, but not limited to, a 9.87 MW biogas generator project, a 15 MW energy storage system, and a 10 MW diesel synchronous generator project.

E3.2 Forecasted DER Connections

Toronto Hydro's 2023-2029 DER connection and capacity forecast considers a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of the forecast.[2] Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching nearly 4,500 connections by the end of 2029, as shown in Figure 2. This represents a total DER installed capacity of approximately 516.7 MW by the end of 2029 in comparison to the 304.9 MW installed as of the end of December 2022, depicted in Figure 3.

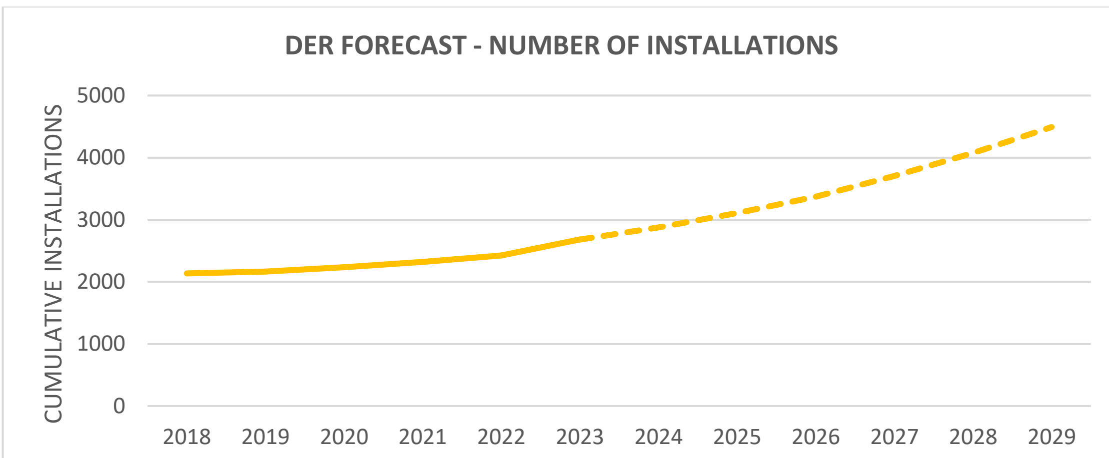


Figure 2: Historical and Forecasted DER Installations

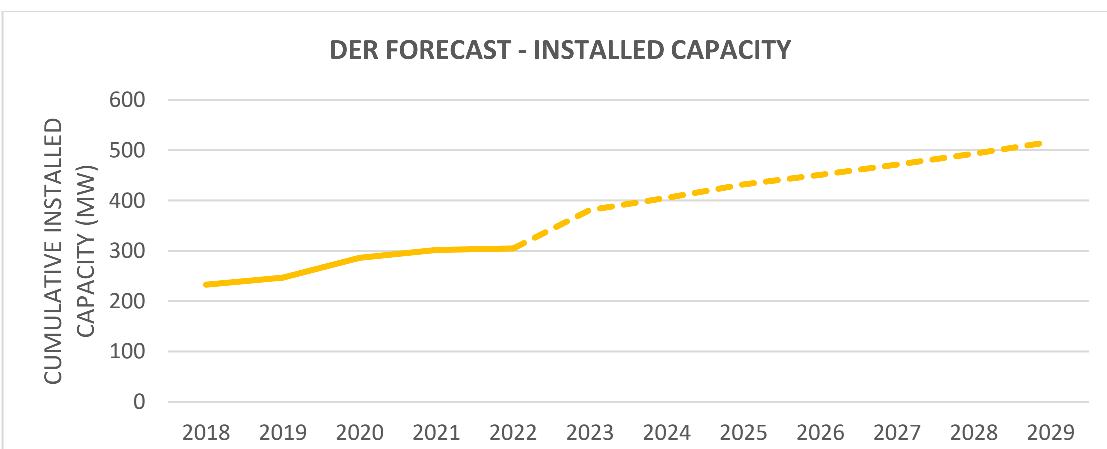


Figure 3: Historical and Forecasted Installed DER Capacity

[2] See Exhibit 2B, Section E5.1.3.2 for further details of Toronto Hydro's DER connection forecast methodology.

Toronto Hydro organizes its DER forecast into renewable, energy storage and non-renewable categories. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With more emphasis on decarbonization, it is expected that the combined installed capacity for renewable and energy storage facilities could surpass non-renewables by 2029 as shown in Figure 4.

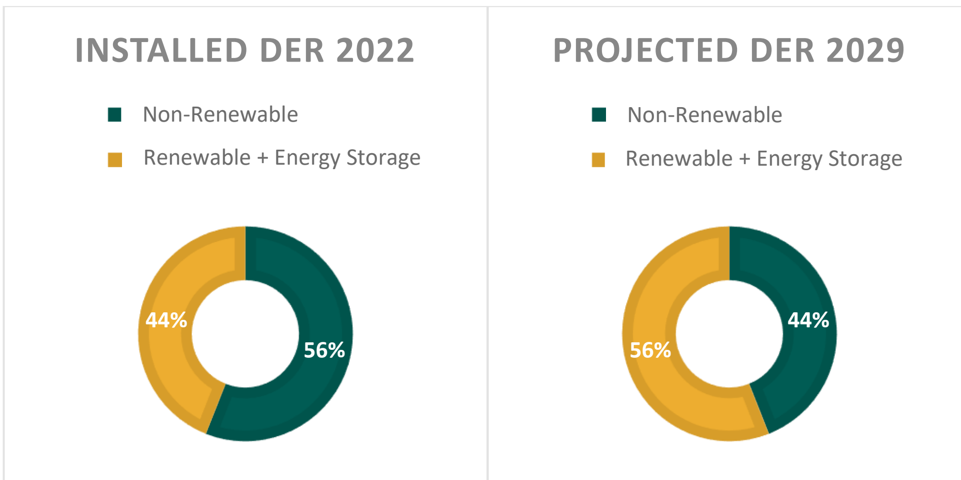


Figure 4: DER Composition by Installed Capacity

E3.2.1 Forecasted Connections for Renewable

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to approximately 200 MW as shown in Figure 5. This rate of growth is in alignment with the Ontario Distributed Energy Resources Impact Study conducted by ICF and submitted to the OEB in 2021.[3]

[3] Ontario Energy Board, ICF, Ontario DER Impact Study (January 18, 2021), online, https://www.oeb.ca/sites/default/files/ICF-DER-impact-study-20210118.pdf

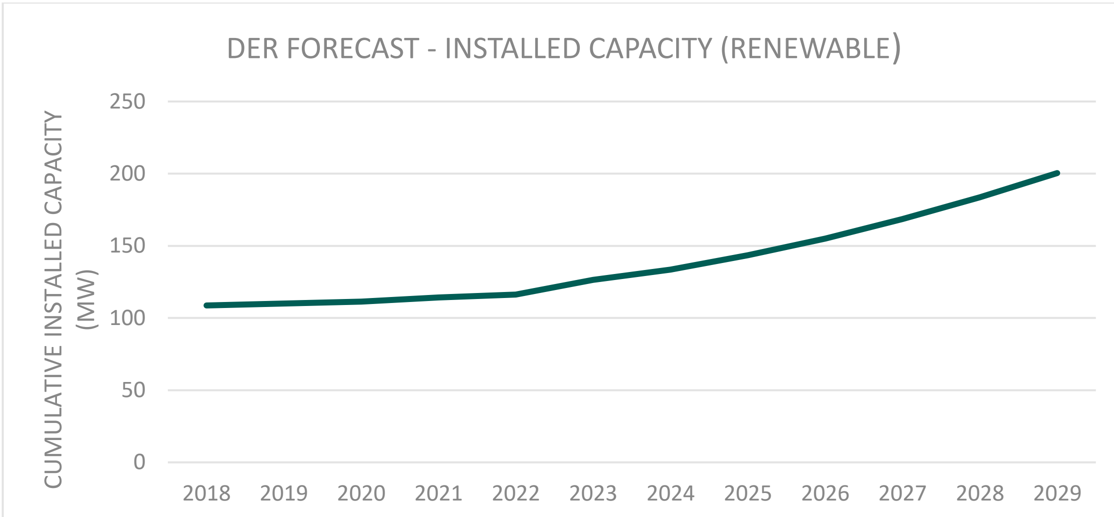


Figure 5: Historical and Forecasted Renewable DER Installed Capacity

E3.2.2 Forecasted Connections for Energy Storage

Although in recent years Toronto Hydro saw a reduced interest in energy storage projects, the utility forecasts a return to high growth by the end of decade. As of the end of 2022, Toronto Hydro connected 28 energy storage projects with total generating capacity of 18.7 MW, the vast majority of which are used in commercial and industrial applications, including for the reduction of global adjustment charges. Toronto Hydro's current energy storage project pipeline anticipates the connection of 12 projects by the end of the year with a combined capacity of 31.9 MW.

Beyond 2025, Toronto Hydro expects that energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. Between 2023 and 2029, Toronto Hydro forecasts over 50 additional energy storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed energy storage capacity to 89.5 MW, as depicted in Figure 6.

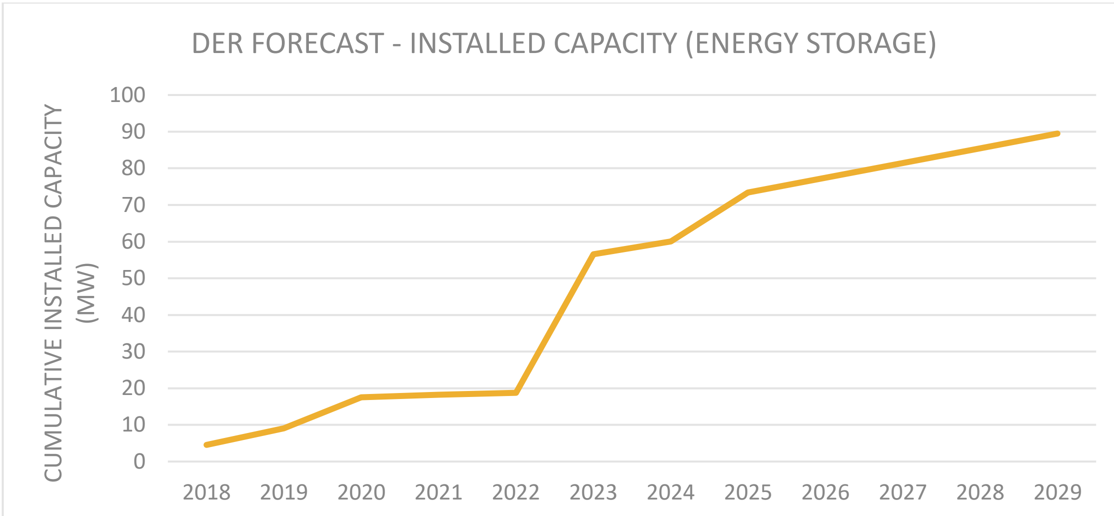


Figure 6: Historical and Forecasted Energy Storage Capacity

E3.2.3 Policy Considerations

Customer choice is the key driver of DER demand, and this driver can be greatly impacted by policy, including the available funding and incentives. The FIT program is a testament to the significant impact that policy and incentives can have on the renewable DER uptake by customers. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to 108.7 MW—a compound annual growth rate of 62.2 percent. When the FIT program ended, the renewable energy annual average growth rate fell to 1.7 percent over 2018 to 2022.

Policies and economic factors that may impact the rate of renewables and energy storage connections include:

- **Green Energy Tax Credit –** Announced by the Federal Government in November 2022, the Green Energy Tax Credit is a refundable credit of up to 30 percent of the capital cost of investments in specific generation systems, including solar PV and battery storage systems.[4]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities,

[4] Environment and Climate Change Canada, Clean Investment Tax Credits in Budget 2023, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

opening up access to the program for customers who may not be in a position to own or operate their own behind-the-meter renewable energy generating equipment.[5]

- **Lithium Ion Battery Cost** – Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[6] The combination of solar PV and energy storage allows users to maximize the use of solar PV generated energy that can only be captured during the day.
- **Ultra-Low Overnight Price Plan** – In 2023, Ontario launched an "Ultra-Low" (ULO) overnight price plan for residential and small business customers. The ULO plan offers an overnight rate of 2.4 cents per kWh (down from 7.4 cents)[7] providing an incentive for storing energy overnight and discharge it during the day when the price is higher.
- **Industrial Conservation Initiative (ICI) program** – Commercial and industrial customers who opt into the Industrial Conservation Initiative (ICI) program can reduce their global adjustment charges through peak shaving using energy storage systems.

The timing, impact and probability of customer demand is subject to a host of policy, economic and technology factors that are difficult to predict. While Toronto Hydro considered the programs and incentives that are currently available to customers in preparing its DER forecast, actual growth rates could materially differ from what the forecast anticipates if new programs or incentives become available.[8] As such, the utility needs flexibility to adapt its plans in response to external factors which could drive up greater customer demand for renewables or energy storage. To enable this flexibility over the 2025-2029 rate period, Toronto Hydro's Custom Rate Framework proposes a mechanism known as the Demand Related Variance Account (DRVA). For more information about the DRVA, please refer to Exhibit 1B, Tab 2, Schedule 1.

[5] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts , "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net

[6] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

[7] https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[8] See, for example, the Future Energy Scenarios Report where consumer choice modelling of the uptake scenarios for rooftop solar PV showed a range of installed capacity by 2050 of between 400 MW to 1,200 MW; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* at pages 67-70.

E3.2.4 Forecasted Connections for Non-Renewable

Toronto Hydro's pipeline for non-renewable DER currently consists of 8 projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW as shown in Figure 7.

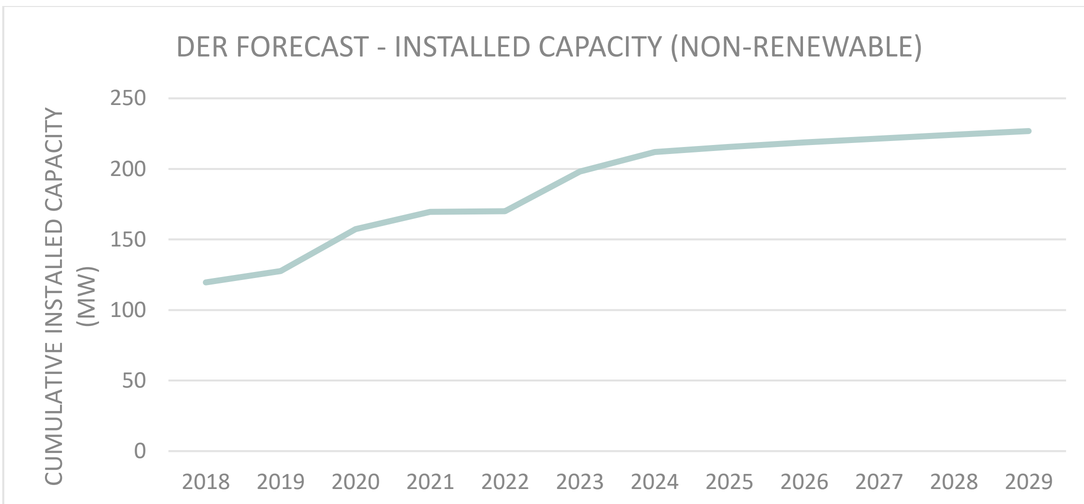


Figure 7: Historical and Forecasted Non-Renewable Capacity

While Toronto Hydro anticipates government policy to gradually reduce the use of non-renewable sources of energy in the journey to reaching net zero goals, the most common applications of non-renewable DER do not yet have viable or technologically mature alternatives. For example, gas generators remain a preferred method of backup generation as they can run for long periods of time in the event of a prolonged outage. Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity.

E3.3 System Capability to Connect DER

Toronto Hydro's system capability to connect renewable DER facilities is subject to a number of considerations, including short-circuit capacity, the risk of islanding, thermal limits, and the inability to transfer loads between feeders during planned work. Each of these considerations is described in greater detail below.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DERs in situations where short circuit capacity limitations exist. Short circuit capacity is electrical system or component's capacity to withstand without permanent damage, high levels of electrical energy congregating on that point or location. Figure 8 below is a map which shows the areas within Toronto's grid that are approaching, or have reached, short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. transformers and directly connect to Toronto Hydro feeders.

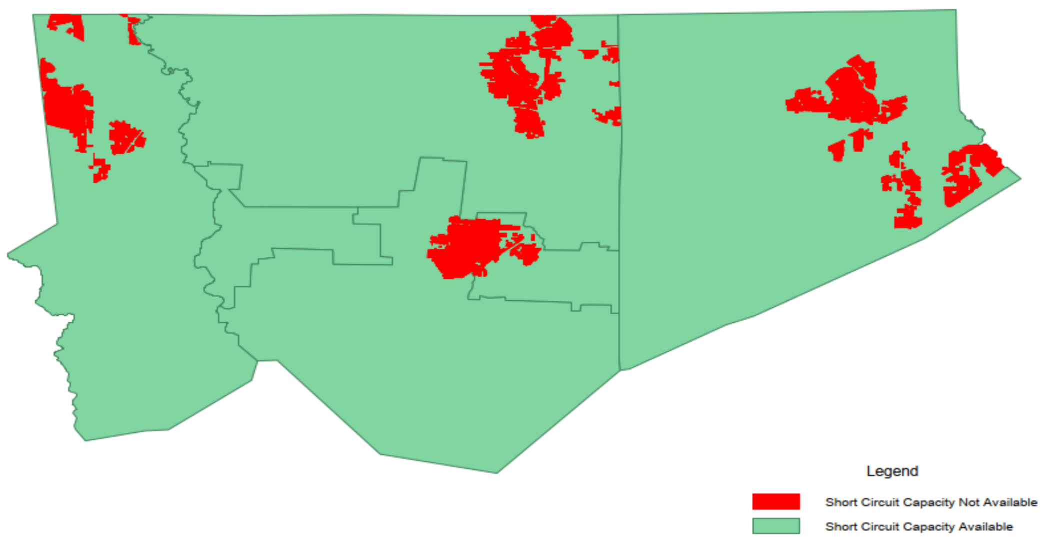


Figure 8: Map of Distribution System Short Circuit Capacity Constraints

Toronto Hydro maintains a list of restricted feeders on its website that is updated every 3 months in accordance with section 6.2.3 (g) of the Distribution System Code. As of July 2023, Toronto Hydro has five transformer station bus pairs that are restricted leading to 48 total restricted feeders due short circuit capacity constraints, as outlined in Table 1 below.

Table 1: Restricted Feeders and Number of Connected Customers

Station Name	Feeder Designation	Restriction	No. of Connected Customers
Sheppard TS, Bus EZ	47-M4	Short Circuit Capacity	0
	47-M6	Short Circuit Capacity	3378
	47-M1	Short Circuit Capacity	3952

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	47-M5	Short Circuit Capacity	0
	47-M2	Short Circuit Capacity	0
	47-M8	Short Circuit Capacity	618
	47-M7	Short Circuit Capacity	1293
	47-M3	Short Circuit Capacity	5909
Woodbridge TS, Bus BY	D6-M1	Short Circuit Capacity	662
	D6-M2	Short Circuit Capacity	0
	D6-M3	Short Circuit Capacity	0
	D6-M4	Short Circuit Capacity	322
	D6-M5	Short Circuit Capacity	0
	D6-M6	Short Circuit Capacity	0
Leslie TS, Bus BY	51-M1	Short Circuit Capacity	0
	51-M3	Short Circuit Capacity	1794
	51-M5	Short Circuit Capacity	1065
	51-M7	Short Circuit Capacity	5663
	51-M2	Short Circuit Capacity	0
	51-M4	Short Circuit Capacity	625
	51-M6	Short Circuit Capacity	2196
	51-M8	Short Circuit Capacity	2582
Leaside TS, Bus AQ	A-5-L	Short Circuit Capacity	54
	A-6-L	Short Circuit Capacity	30
	A-10-L	Short Circuit Capacity	65
	A-12-L	Short Circuit Capacity	1990
	A-13-L	Short Circuit Capacity	1934
	A-16-L	Short Circuit Capacity	5
	A-17-L	Short Circuit Capacity	32
	A-21-L	Short Circuit Capacity	2058
	A-22-L	Short Circuit Capacity	2623
	A-26-L	Short Circuit Capacity	34
	A-1-L	Short Circuit Capacity	0
	A-3-L	Short Circuit Capacity	6

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	A-28-L	Short Circuit Capacity	10
	A-2-L	Short Circuit Capacity	0
	A-4-L	Short Circuit Capacity	12
	A-27-L	Short Circuit Capacity	20
	A-14-L	Short Circuit Capacity	2019
Richview TS, Bus BY	88-M1	Short Circuit Capacity	90
	88-M3	Short Circuit Capacity	127
	88-M5	Short Circuit Capacity	0
	88-M7	Short Circuit Capacity	0
	88-M2	Short Circuit Capacity	1651
	88-M4	Short Circuit Capacity	0
	88-M6	Short Circuit Capacity	0
	88-M8	Short Circuit Capacity	49

Toronto Hydro is working with Hydro One to mitigate these restrictions by re-examining feeder limits and making planned investments in bus tie reactors as part of the Generation Protection Monitoring and Control (GPMC) program at Exhibit 2B, Section E5.5.

2. Anti-Islanding Condition for DER

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and pose a serious safety risk to crews who perform work on Toronto Hydro's system. To safeguard against this risk, the connection of photovoltaic solar inverters and other DER sources must prevent unintentional islanding, as per IEEE 1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces).[9] Toronto Hydro plans to continue to deploy real-time monitoring and control investments at every new DG site to protect against the risk of islanding. For more information please refer to the GPMC program at Exhibit 2B, Section E5.5.

[9] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023, vol., no., pp.1-322, 11 Aug. 2023 ("IEEE P1547.2/D6.5").

As the ratio of generation capacity to minimum load on a feeder increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice[10] Toronto Hydro aims to ensure that "DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS)"[11] – i.e. minimum generation to load ratio (MLGR).

Toronto Hydro conducted an analysis for all feeders in its system to establish MLGR in accordance with applicable guidance found in IEEE-P1547.2/D6.5, August 2023.[12] The results of study, summarized in Table 2 below, show that 23 feeders are below the recommended ratio, and that by 2029 an additional 24 feeders could be below the ratio based on the DER forecast for renewables.

Table 2: MLGR Feeder Analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35

[10] R. Seguin, et. al., *High-Penetration PV Integration Handbook for Distribution Engineers*, NREL/TP-5D00-63114 (2016), "online", https://www.nrel.gov/docs/fy16osti/63114.pdf
[11] IEEE P1547.2/D6.5.
[12] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, 11 Aug. 2023.

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

To address islanding concerns and enable safe connection of renewable DERs on feeders with a high generation to load ratio, an energy storage system (ESS) can be installed on the feeder to act as a load to manage MLGR when the minimum load is low. For more information, please refer to the Renewable Battery Energy Storage System segment of the Non-Wires Solutions program at Exhibit 2B, Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation, or aggregated generation, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure. Monitoring and control equipment allows Toronto Hydro to monitor and mitigate feeder thermal loading.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies, as thermal limits are indicative of the grid's equipment withstand capabilities. Since contingencies and feeder planned work occur particularly on feeder load transfers, it is imperative to assess the relative impact DER would impose particularly those larger capacity generators. Real-time monitoring and control would provide this window of information.

E3.3.1 Planned Investments to Eliminate Constraints

In order to connect the forecasted DERs to Toronto Hydro's distribution system, the following solutions have been identified as planned investments for the 2025 to 2029 period:

1) Six bus-tie reactors to alleviate short circuit capacity constraints at stations that cannot be relieved through station expansion work or by increasing station equipment thresholds. Table 3 below identifies the station buses where bus tie reactors are proposed.

Table 3: Locations of Proposed Bus Tie Reactors (2025-2029)

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Woodbridge	D6-BY	-27.3	-28.0

2) Real-time monitoring and control systems must be installed at every site to monitor for islanding and thermal conditions.[13] In accordance with the Distribution System Code, monitoring and control systems for renewables are paid for by the distributor rather than the customer as is the case for non-renewables.
3) Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on the nine high-priority feeders outlined in Table 3 above. The utility selected these feeders based on their existing high renewable DER penetration, low MLGR ratio and high forecasted renewable DER growth. Please refer to the Non-Wires Solutions program for more information about the feeder selection process and analysis (Exhibit 2B, Section E7.2).

[13] Exhibit 2B, Section E5 – Generation Protection and Control, section E5.5.4.2.

E4 Capital Expenditure Summary

This section provides an overview of Toronto Hydro's capital and system maintenance and operational (O&M) expenditures for the 2020-2029 rate period, including explanations of: (i) variances in forecast expenditures from the 2020-2024 capital plan versus actual expenditures during over the 2020-2024 rate period, and (ii) shifts in 2025-2029 forecast expenditures versus 2020-2024 historical expenditures by investment category.

The explanations provided in this section are complimentary to the information presented in OEB Appendices 2-AB,[1] and 2-AA which are appended to this section.[2] Detailed explanations for material variances and trends are also provided within the 'Expenditure Plan' section of each capital program in sections E5 to E8.

<u>Accounting Treatment for CWIP</u>

Expenditures for capital projects that span more than one calendar years are recorded in a Construction Work-in Progress ("CWIP") account until the project work is completed. Given the nature of its capital expenditure programs and projects, at any point in time, Toronto Hydro has a balance in the CWIP account. Initial capital expenditures are recorded in CWIP until the project is complete, and capitalized. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that exceed six months to complete. AFUDC is part of Other Capital Expenditures as further explained below.

<u>Other Capital Expenditures</u>

Toronto Hydro's capital expenditures under the Other Capital Expenditures category includes Allowances for Funds Used During Construction ("AFUDC") and miscellaneous capital, as described in OEB Appendices 2-AB.[3]

- AFUDC is capitalized in accordance with the OEB's Accounting Procedures Handbook, Article 410. The AFUDC rate applied by Toronto Hydro under MIFRS for 2020 to 2022 actuals, 2023

[1] Exhibit 2B, E4, Appendix A
[2] Exhibit 2B, E4, Appendix B
[3] *Supra* note 1.

to 2024 bridge, and 2025 to 2029 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.

- Miscellaneous capital primarily consists of pre-capitalized inventory and major tools. The value of pre-capitalized inventory results from the change in capitalized inventory levels between years.[4] The utility purchases major tools in the normal course of operations and on an ongoing basis to replace worn or broken tools, as required, and to install, commission and otherwise complete capital activities.

E4.1 Plan versus Actual Variances for 2020-2024

In Toronto Hydro's 2020-2024 rate application, the OEB approved a custom incentive rate-setting mechanism on the basis of a capital expenditure plan of $2,710.7 million.[5]

Due to the imposition of a 0.9% stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity.
- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition.

[4] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors*, (January 1, 2012), Article 410.
[5] EB-2018-0165, Draft Rate Order (Filed: January 21, 2020; Updated: February 23, 2020), Schedule 4 – Capital Expenditures.

- Staying on track to complete Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time within budget.

As described in Section D1, Toronto Hydro goes through an extensive annual business planning process to strike a balance across these objectives. To ensure the utility was able to meet specific needs of the system (including those listed above) and manage within the operating conditions of the current period (including 40-year high inflation), Toronto Hydro had to reduce the pacing of certain system renewal investments: [6]

- the replacement of direct-buried cables as part of its Underground System Renewal – Horseshoe program;[7] and
- the replacement of wood poles in its Overhead System Renewal program.[8]

Reduction in these programs placed additional pressure on reliability performance. Toronto Hydro had to carefully manage these pressures to honour its commitment to maintain reliability performance over this period and meet other key plan objectives noted above. The utility succeeded in this balancing act as it:

- maintained reliability performance relatively consistent over its historical average. The utility's SAIDI performance improved over the last five years (2018-2022), averaging 0.85 hours and exceeding the OEB's distributor target of 0.87 hours. The utility's SAIFI performance is slightly worse than the OEB's distributor target of 1.20, averaging at 1.30 during 2018 to 202, but comparable to the 2013-2022 average of 1.28;
- Connected approximately 10,000 customers through the Customer Connections program, with an increase of $147.5 million (71 percent) in capital expenditures over the forecast to maintain and exceed performance;
- Continued to support expansion and relocation projects as part of the Externally Initiated Plant Relocations and Expansion program including but not limited to the Metrolinx GO expansion project and the TTC initiated Easier Access Program;
- Reduced constraints on the system through the Load Demand program by alleviating 131 MVA on highly loaded buses, reducing the number of highly loaded feeders by 10, improving

[6] As described in detail in Exhibit 1B, Tab 3, Schedule 3, these include COVID-19, extraordinary inflation, and workforce challenges.
[7] Exhibit 2B, Section E6.4.
[8] Exhibit 2B, Section E6.6.

the civil infrastructure associated with station expansion of five Terminal Stations as well as civil rebuild at the distribution level, and maintaining the number of feeders subject to switching restrictions during the summer months to under 10;

- Replaced of approximately 50,000 residential, small commercial, and industrial meters as part of the AMI 2.0 project in the Metering program over the rate period which improves billing accuracy, faster outage response, improved network range, enhanced cyber security protection, increased grid transparency, data granularity and analytical capabilities;[9]
- Completed installations of radio communication link equipment required to facilitate the two-way communication flow between DER facilities and the Toronto Hydro Control Centre at more than 100 sites during the period of 2020 to 2023;
- Replaced 444 box-framed poles with an additional 236 anticipated over the rate period, enabling the utility to meet its commitment to remove box construction poles from the system by 2026;
- Converted 384 customers from aging rear lot service to safer and more reliable front lot underground during 2020 to 2022, and is on track to convert approximately 299 rear lot customers during 2023 to 2024;
- Addressed approximately 3,500 transformers containing or at risk of containing PCBs with upward pressure on the cost of materials attributed to supply chain issues from the COVID-19 pandemic through a combination of inspection and replacement over the course of 2020-2022;
- Addressed aging and failure risk prone direct-buried cable in the underground system through replacement of 79 kilometers of direct-buried cable over 2020-2023 for an estimated total of 105 kilometers by the end of the rate period;
- Continued to address obsolete PILC and AILC cable through the Underground Renewal – Downtown program by replacing an estimated 30 circuit-km of PILC cable and 9 circuit-km of AILC over the 2020-2024 rate period;[10]
- Addressed deteriorated and non-submersible units through the investments in the Network System Renewal program by replacing 82 network units and an additional 95 network units by the end of the rate period;[11]

[9] Exhibit 2B, Section E5.4.
[10] Exhibit 2B, Section E6.3.
[11] *Supra* note 8.

- Improved flexibility of the system through investments in the System Enhancements program that includes the addition of tie points, sectionalizing points and upgrades to undersized loops, and installation of switchgear ties between Copeland and Windsor stations;[12]
- Continued to advance capabilities and build upon progress from the previous rate period through Local Demand Response initiatives outlined in the Non-Wires Solutions program (E7.2) by targeting Manby TS and Horner TS over the 2020-2024 period;
- Commissioned 379 vaults with an additional 320 over the rate period to modernize just under 90 percent of the secondary network through the Network Condition Monitoring and Control ("NCMC") program,[13] achieving sustained operating expenditure savings and improved network resiliency; and gaining crucial organization grid modernization experience that will be applied to the 2025-2029 rate period;
- Increase the capacity of Copeland Station with a Phase 2 expansion that provides an addition 144MVA to support the growth and development of Central Waterfront area and enhance reliability and resiliency in the downtown core. This project is on time and below budget by approximately $5 million.[14]
- Improving operational resilience and strengthening system security by completing construction of a dual Control Centre by the end of 2023; and
- Improving cyber security and business efficiency and laying the foundation for future customer experience enhancements by upgrading the Customer Information System ("CIS") to a modern, vendor-supported version by Q2 of 2024.

Toronto Hydro forecasts $2,787.4 million in net capital expenditures over the completion of the 2020-2024 rate period, which is three percent higher than the $2,710.7 million approved by the OEB in the 2020-2024 DSP.

In Table 2 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to the OEB Approved values for 2020-2024 as the "Plan" for 2020-2024. By comparing the 2020-2024

[12] Exhibit 2B, Section E7.1.
[13] Exhibit 2B, Section E7.3.
[14] Copeland Phase 2 savings are derived from continuous improvement in execution based on the utility's experience and lessons learned from Copeland Phase 1. For example, more cost-effective procurement agreements for major equipment.

plan to the actual and forecasted bridge year expenditures, the utility is able to provide a complete picture of the management and execution of the current plan.

Table 2 below provides a breakdown of the Plan and of actual plus bridge expenditures by year and by category, and the subsections that follow the table provide explanations for each category:

Table 2: 2020-2024 Capital Expenditure Summary ($ Millions)

OEB Category	Historical									Bridge					
	2020			2021			2022			2023			2024		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	164.9	225.2	37%	193.0	240.7	25%	184.7	244.3	32%	197.4	260.5	32%	211.1	289.6	37%
System Renewal	290.5	261.7	(10%)	307.2	247.3	(19%)	304.7	276.6	(9%)	319.4	314.0	(2%)	309.5	358.8	16%
System Service	34.6	33.4	(3%)	60.1	68.0	13%	71.3	67.1	(6%)	33.6	32.8	(2%)	38.5	24.3	(37%)
General Plant	78.8	56.1	(29%)	92.8	72.4	(22%)	88.1	112.9	28%	76.8	96.5	26%	84.4	80.7	(4%)
Other	5.3	17.5	232%	6.5	4.8	(26%)	8.9	12.8	44%	6.3	12.6	100%	5.7	7.7	35%
Total CAPEX	**574.1**	**593.9**	**3%**	**659.6**	**633.3**	**(4%)**	**657.7**	**713.7**	**9%**	**633.5**	**716.4**	**13%**	**649.3**	**761.2**	**17%**
Capital Contributions	(74.8)	(145.8)	95%	(102.7)	(100.1)	(2%)	(93.9)	(115.8)	23%	(94.5)	(133.4)	41%	(97.6)	(135.9)	39%
Net CAPEX	**499.2**	**448.1**	**(10%)**	**556.9**	**533.2**	**(4%)**	**563.8**	**597.9**	**6%**	**539.1**	**582.9**	**8%**	**551.7**	**625.3**	**13%**
System O&M	126.3	117.1	(7%)	-	117.5	-	-	124.1	-	-	127.1	-	-	135.0	-

Note: Capital contributions include contributions made by customers and third-parties.

E4.1.1 System Access 2020-2024 Variance Analysis

From 2020 to 2024, System Access expenditures are forecasted to be approximately 33 percent higher than planned due to the following factors:

- Expenditures in the Customer Connections program are forecasted to be approximately 55 percent higher than the plan on a gross basis and 71 percent higher on a net basis.[15] This program is highly volatile and driven by various external factors (e.g. size and location of connections, available capacity provisions, economic drivers). Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (greater than 5MVA demand) over this period. The increases in 2021-2022 were attributed to the unforeseen emergence of large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). Toronto Hydro factored in these trends in developing its 2025-2029 forecasts. See the Customer Connections program for additional details.

[15] Exhibit 2B, Section E5.1.

- Expenditures in the Load Demand program are forecasted to be approximately 38 percent higher than planned.[16] This variance was driven by the need for load transfers between stations and feeders to alleviate system constraints. Like Customer Connections, the Load Demand program can vary significantly from one year to the next due to expected new connections, voltage conversions, and an updated station load forecast. To keep up with these drivers, the Load Demand program forecast is re-evaluated annually.
- Expenditures in the Externally Initiated Plant Relocations and Expansions program are forecasted to be approximately 18 percent higher than planned due to an increase in the volume and complexity of third-party relocation and expansion projects.[17]
- Expenditures in the Metering Program are forecasted to be 34 percent lower than planned. Due to procurement delays and funding constraints, Toronto Hydro adjusted the pacing of meter replacements in the current rate period.[18]

E4.1.2 2020-2024 Variances: System Renewal

From 2020 to 2024, System Renewal expenditures are forecasted to be approximately 5 percent lower than planned due to the following factors:

- Expenditures in the Area Conversions program are forecasted to be approximately 24 percent higher than planned.[19] The net increase in the program is driven by the Box Construction Conversion segment, which saw higher spending due to required shifts in project scheduling as well as incremental cost pressures related to the complexity of the work and various external cost drivers (e.g. coordination with the CafeTO program). For more details, please refer to section E6.1.4.2. The Rear Lot Conversion investments also saw a slight increase of approximately 4 percent.
- Expenditures in the Underground System Renewal – Horseshoe,[20] and Underground System Renewal – Downtown are forecasted to be approximately 24 percent lower than planned.[21] Through its planning and execution process, Toronto Hydro determined that it was necessary to constrain investment in these programs in order to manage funding pressures and balance

[16] Exhibit 2B, Section E5.3.
[17] Exhibit 2B, Section E5.2.
[18] *Supra* note 9.
[19] Exhibit 2B, Section E6.1.
[20] Exhibit 2B, Section E6.2.
[21] *Supra* note 10.

the attainment of multiple objectives within the plan. The utility temporarily shifted its execution strategy to a target spot replacement approach focused on PCB removals, which meant taking on incremental risk in its aging cable population. That accumulation asset failure risk is driving the need for incremental investment in key underground assets such as cables in 2025-2029. In Downtown program, Toronto Hydro was able to find some savings over the 2020-2024 rate period by engineering an alternative approach to cable renewal work which leverages existing available civil infrastructure to the extent possible.

- Expenditures in the Overhead System Renewal program are forecasted to be approximately 18 percent lower than planned due to the same considerations,[22] as discussed above for the Underground Renewal program. Toronto Hydro managed a reduced pace in this program by temporarily shifting its execution strategy to a spot replacement approach focused on PCB removals, and deferring larger area rebuilds to address deteriorating poles and switches as well as obsolete 4 kV feeders.
- Expenditures in the Network System Renewal program are forecasted to be approximately 26 percent higher than planned.[23] The increase is driven in large part by design and execution complexities that emerged as the projects matured from conceptual to detailed design. This includes additional scope of work (e.g. civil construction and legacy cable removal), material cost increases driven by supply chain disruptions, and work execution challenges related to field conditions (e.g. urban congestion) and operational complexities (e.g. coordination challenges).
- Expenditures in the Stations Renewal program are forecasted to be approximately 23 percent higher than planned due to project complexity, necessary scope increases, and inflationary cost escalations.[24]

E4.1.3 2020-2024 Variances: System Service

From 2020 to 2024, System Service expenditures are forecasted to be approximately five percent lower than planned due to the following factors:

[22] Exhibit 2B, Section E6.5.
[23] *Supra* note 7.
[24] *Supra* note 8.

- Expenditures in System Enhancements program are forecasted to be approximately 5 percent lower than planned.[25] Toronto Hydro constrained the pace of investment in this area by deferring work to the 2025-2029 rate period and by leveraging opportunities to carry out some of the planned enhancement work within related renewal programs.
- Expenditures in the Energy Storage Systems (ESS) segment, which has been re-mapped to the Non-Wires Solutions program, are forecast to be 79 percent lower than planned due to challenges in finding a cost-effective site for an ESS installation, as well as supply chain constraints. Faced with these challenges, and further studying the use cases and the regulatory considerations of ESS as a grid-asset Toronto Hydro decided to evolve its ESS investment strategy to focus on enablement of renewables electricity generation resources.[26]

Phase 2 of Copeland TS is expected to be completed in early 2024, therefore, there are no expansion costs forecast for the 2025-2029 rate period. 2020-2024 expenditures are forecast to be about 1 percent higher than planned. For further details, please refer to Stations Expansion program.[27]

E4.1.4 2020-2024 Variances: General Plant

From 2020-2024, General Plant expenditures are forecasted to be aligned with the Plan, as a result of variances in the following programs offsetting each other:

- Expenditures in the Facilities Management and Security program are forecasted to be 41 percent higher than planned due to need for additional unplanned reactive asset replacements, such as the replacement of a failed HVAC unit at the 14 Carlton work centre, the installation of hatchway railings and safety devices, and physical security enhancements in response to security incidents; incremental work to reduce building emissions;, and overall higher costs of materials and labour driven by supply chain disruptions and inflationary pressures in the construction industry.[28]
- Expenditures in the IT/OT program are forecasted to be 8 percent lower than planned. Increases in cybersecurity investments required to reinforce system protection due to an increase in external threats were offset by savings resulting from the prudent decision to

[25] *Supra* note 12.
[26] Exhibit 2B, Section E7.2.
[27] Exhibit 2B, Section E7.4.
[28] Exhibit 2B, Section E8.2.

defer the Enterprise Resource Planning ("ERP") system upgrade. Toronto Hydro made this decision when it learned that the system vendor, SAP, extended maintenance support for the existing ERP platform until 2027, and extended support until 2030.[29]

The Control Operations Reinforcement Program included in the 2020-2024 Plan is expected to be complete before 2025-2029 on time and within budget.[30]

E4.1.5 2020-2024 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 69 percent higher than forecast over the 2020-2024 rate period. The primary driver for this increase is a result of a strategic decisions to increase pre-capitalized inventory to mitigate plan execution risks driven by supply chain disruptions (i.e. extended lead times and delivery uncertainty) experienced during the COVID-19 pandemic. This decision enabled Toronto Hydro to ensure equipment availability for its growing capital program, including critical compliance investments in at-risk PCB transformer replacements.[31]

E4.1.6 2020-2024 Variances: System O&M

System Operations and Maintenance ("System O&M") expenditures are driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The expenditures include the following activities:

- Preventative and Predictive Maintenance Programs (Exhibit 4, Tab 2, Schedule 1-3);
- Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4)
- Emergency Response (Exhibit 4, Tab 2, Schedule 5);
- Disaster Preparedness Management (Exhibit 4, Tab 2, Schedule 6);
- Control Centre Operations (Exhibit 4, Tab 2, Schedule 7);
- Customer Operations (Exhibit 4, Tab 2, Schedule 8);
- Asset and Program Management (Exhibit 4, Tab 2, Schedule 9);
- Work Program Execution (Exhibit 4, Tab 2, Schedule 10); and

[29] Exhibit 2B, Section E8.4.
[30] EB-2018-0165, Exhibit 2B, Section E8.1.
[31] Please refer to Exhibit 4, Tab 2, Schedule 13 for further details on supply chain challenges

- Supply Chain (Exhibit 4, Tab 2, Schedule 13);

System O&M expenditures are forecast to increase from approximately $117.1 million in 2020 to $135 million in 2024, representing an average annual increase of 4 percent over the period. The primary drivers are asset and system maintenance needs, compliance obligations and resource requirements to support a higher volume and greater complexity of work in Toronto Hydro's service territory as the city of Toronto continues to grow, digitize, and decarbonize its economy. Below is a more detailed list of specific drivers:

- Corrective maintenance to address safety, reliability and environmental risks arising from a higher number of deficiencies identified through inspection programs.
- Compliance with incremental requirements imposed by the Electrical Safety Authority with respect to grounded-wye customer supply points and grounding of unused primary lines.
- The introduction of a Cable Diagnostic Testing program to support a more targeted approach for managing short-term cable systems risks.
- An increase to the Vegetation Management program to mitigate the reliability impacts of Toronto's expanding tree canopy.
- Increased overhead switch maintenance volumes and costs to ensure optimal maintenance cycles and keep pace with a growing population of assets.
- Greater requirements for testing, resealing, and reusing meters.
- The introduction of incremental Storm Guying inspections and corrective action to improve resiliency of poles during high wind events.
- The introduction of inspections for communication infrastructure at DER sites.
- Workforce requirements to support higher volumes and complexity of work, prepare the grid for energy transition and build capabilities required to support grid modernization objectives, including improvements to data quality and additional analytical capacity.
- An increase due to external factors such as weather in Emergency Response and customer demand for services such as vault access, locates and connections in Customer Operations.

The volume of maintenance for an asset class is dictated by asset class maintenance cycles and can vary from year-to-year. Similarly, the extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors. To manage natural variances and volatility in maintenance programs, Toronto Hydro paces the execution of its maintenance plans where feasible and appropriate. For example, an increase in station battery failure for a particular year may be offset by a deferral of checker plate replacements at submersible vault locations or vault cleaning activities in Network Vaults.

E4.1.6.1 Capital Investment and System O&M

While capital investments can impact System O&M costs in different ways as discussed below, identifying specific impacts for each year is not practical due to the numerous factors involved and the gradual and ongoing nature of many of these impacts. Instead, the following summarizes and provides examples of the various ways System O&M costs are impacted by capital investments.

As discussed in more detail in Section D3.1.1.3, a significant portion of maintenance program costs are for activities which are independent of capital investments, such as cyclical inspections to meet minimum requirements under the Distribution System Code, and, where there is an impact of capital investments, the directional relationship depends on a number of factors, including the type of capital investment. For example, Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increases. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets under the Preventative and Predictive Station Maintenance program and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program. [32,33] While Modernization investments can similarly increase maintenance costs by installing new assets such as SCADA-mate switches, it can also help to reduce some O&M costs. For example, the NCMC program installs sensors in network vaults providing remote monitoring and control, and through this Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned. [34] While this benefit of the NCMC program

[32] Exhibit 4, Tab 2, Schedule 3.
[33] *Supra* note 26.
[34] Exhibit 4, Tab 2, Schedule 2.

is not expected to be realized until 2027, the utility has already avoided costs by reducing the need for crews to visit vaults during outage events or to identify and investigate deficiencies.[35]

For Sustainment investments, typical like-for-like asset replacement is generally expected to have minimal to no impact on maintenance spending. If replacements are done at a high enough pace to materially improve asset health demographics (which is generally not the goal), this could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, this is complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). Toronto Hydro does anticipate that Sustainment programs targeting legacy assets such as air-blast circuit breakers and the 4.16 kV system (including box construction and rear lot) will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs (including emergency or corrective maintenance) or is maintenance free. For example, air-blast circuit breakers rely on air compressors, which Toronto Hydro inspects and maintains twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through its Stations Renewal program, it will reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[36]

As discussed in more detail in Section E4.2.6 below, growth in the overall size of the capital investment program is expected to increase costs in O&M programs that support such investments, including Asset and Program Management,[37] and Supply Chain.[38]

E4.1.7 2020-2024 Construction Work in Progress ("CWIP")

Table 3 below provides the 2020-2024 CWIP. Detailed explanations for capital expenditures are provided above and explanations for trends in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

[35] For example, as of June 2023 Toronto Hydro had saved approximately $120,000 by not deploying crews during outage events. See Exhibit 2B, Section E7.3 for more details on the NCMC program and its benefits.
[36] Exhibit 2B, Section E6.6 and Exhibit 4, Tab 2, Schedule 3.
[37] Exhibit 4, Tab 2, Schedule 9.
[38] Exhibit 4, Tab 2, Schedule 13.

Table 3: Historical (2020-2022) and Bridge (2023-2024) CWIP ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
Opening CWIP	381.2	380.6	427.8	471.2	442.4
Additions (CAPEX)	447.4	532.4	597.8	579.1	620.3
Deductions (In Service Additions)	(447.9)	(485.2)	(554.4)	(607.9)	(606.3)
Closing CWIP	380.6	427.8	471.2	442.4	456.4

Note: Variances due to rounding may exist

E4.2 Forecast (2025-2029) vs. Historical (2020-2024) Expenditures

Table 4 below shows the contribution to the total capital program of each investment category for the current and future rate period. Compared to the current 2020-2024 rate period, there is a shift in the 2025-2029 rate period towards System Access and System Service investments to:

- keep pace with the demands of customers in a city that is growing, digitizing and decarbonizing its economy, and
- prepare the grid for the energy transition that is set to unfold over the next two decades by modernizing the utility's infrastructure and operations to improve resiliency, enable DER integration and deliver long-term reliability and efficiency benefits to customers.

Table 4: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2020	2021	2022	2023	2024	Avg.	2025	2026	2027	2028	2029	Avg.
System Access	18%	26%	21%	22%	25%	**22%**	31%	31%	27%	23%	23%	**27%**
System Renewal	58%	46%	46%	54%	58%	**53%**	49%	48%	47%	50%	53%	**49%**
System Service	7%	13%	11%	6%	4%	**8%**	6%	5%	10%	12%	11%	**9%**
General Plant	13%	14%	19%	17%	13%	**15%**	14%	16%	15%	14%	12%	**14%**
Other CAPEX	4%	1%	2%	2%	1%	**2%**	1%	1%	1%	1%	1%	**1%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

In the sections that follow, Toronto Hydro provides a summary of key programs and investment priorities that are driving the planned increases in each of these categories in 2025-2029 compared to 2020-2024. Additional details about each of these programs and priorities are found throughout other section of this Distribution System Plan.

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 5: System Access: 2020-2029 Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	226.5	239.3	228.3	192.8	184.8

Toronto Hydro expects System Access expenditures to continue to increase into the 2025-2029 rate period. As discussed in Section E2.2, this overall increase is driven by two primary considerations:

- continued growth and development in the city of Toronto, including the expected impacts of electrification as more customers turn to electricity for their day to day needs such as transportation and building heating systems;
- necessary replacement of end-of-life revenue meters which will also offer Toronto Hydro the opportunity to modernize this critical part of the system with Advanced Metering Infrastructure (AMI) 2.0.

As discussed in Section D2, the City of Toronto leads North America in new buildings under construction. Toronto Hydro expects continued growth in customer load and generation connections, as well as major infrastructure projects (e.g. transit development) that are externally initiated. Toronto Hydro is also due to renew its sizable population of end-of-life residential and small commercial and industrial (C&I) revenue meters.[39] Inflation for materials, labour and other construction-related costs is also driving increases in certain programs. For more information on the programs in this category, refer to Section E5.

[39] *Supra* note 9.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 6: System Renewal Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Renewal investments in the 2025-2029 rate period by approximately 35 percent compared to 2020-2024 rate period. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks, maintain the system in a state of good repair by managing the overall health demographics of assets, and ensure stable and predictable grid performance for current and future customers.

As mentioned in Section E4.1.2 above, Toronto Hydro constrained investment in key System Renewal programs to manage funding pressures in the 2020-2024 rate period. This prudent decision, along with other factors, led to increasing investment needs in the 2025-2029 rate period including:[40]

- asset condition demographics (e.g. wood pole condition);
- persistent backlogs of high-risk legacy assets such as direct-buried cable;
- growing asset stewardship risks in the downtown core, including those related to aging lead cable and deteriorating civil assets;
- growing backlog of critical stations-level equipment at risk of failure;
- increasing performance pressures on the system from climate change, necessitating greater investment in resiliency;
- elimination of PCB at-risk assets from the distribution system;
- the increasingly urgent need to convert aging, legacy 4 kV / 13.8 kV parts of the system to higher voltage standards that are capable of handling electrified loads, DERs and automation;
- the need to accelerate replacement of obsolete mechanical stations relays with digital relays capable of supporting advanced operational functions and grid automation; and

[40] See Sections D1, E2, and Section E6 for additional details.

- anticipated cost pressures from construction inflation in the City of Toronto which reached a 40-year all time high in the 2020-2024 rate period.

Toronto Hydro expects to eliminate PCB at-risk units from the distribution system by 2025 and box-framed poles by 2026. The winddown of these investment priorities will enable the utility to ramp-up investment in the conversion of legacy 4 kV / 13.8 kV parts of the system. In addition to addressing the reliability risks posed by these aging assets, the conversion of these configurations to higher voltage standard enables the utility to accommodate higher volumes of electrified loads.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 7: System Service Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.3	83.0	95.1	101.2

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Service investments by approximately 56 percent compared to 2020-2024 investment levels. Expenditures in this category are central to Toronto Hydro's strategy to expand and modernize its grid and operational capabilities to address key drivers of change within its business, including electrification, DER proliferation, and climate change impacts. For more information about this strategy see Section D4 – Capacity Planning and Electrification Strategy and D5 – Grid Modernization Strategy.

Increased investments in this category are largely driven by:

- capacity expansion needs in the Stations Expansion program including investment in a new Transformer Station to support expected load growth in the Downsview areas and Hydro One contribution to expand capacity at existing stations, such as Scarborough TS.[41]
- a paced ramp-up in the System Enhancement program to enhance system observability and controllability, and enable the utility to be ready for widescale grid automation in the horseshoe areas of its system in the next decade.[42] These investments are expected to deliver long-term reliability and efficiency benefits to customers.

[41] *Supra* note 27.
[42] *Supra* note 12.

- investments in Energy Storage systems (ESS) to improve the grid's capacity to connect and integrate Renewable Energy Generation (REG) connections which are expected to play an increasing role in advancing customers' and stakeholders decarbonization objectives.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 8: General Plant Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6

Over the 2025-2029 rate period, Toronto Hydro plans to increase its General Plant investments by approximately 34 percent compared to 2020-2024. Expenditures in this category are driven by asset lifecycle management for fleet, facilities, and IT equipment that support the efficient execution and management of Toronto Hydro's capital and operational work programs. In addition, Toronto Hydro plans to continue to invest in paced decarbonization of its facilities and fleet emissions, as well as in the relocation of an enterprise data centre. The latter project is required to enable the utility to expand and reliably operate this critical piece of infrastructure in accordance with the growth of the distribution system, as the significant challenges associated with the data centre's current location preclude such expansion and pose significant business continuity and reliability risks.

This category is also driven by investments in cyber security and enterprise technology software solutions, which are needed to achieve the following outcomes:

- strengthen protection and resilience against increasing digital threats brought on by advancements in technology and changes in geopolitical dynamics;
- support grid modernization efforts detailed in Section D5;
- drive continuous improvement in productivity through process automation;
- leverage technology tools and capabilities to serve customers in a timely and effective manner and deliver good experience as more customers turn to electricity for their day-to day energy need; and
- implement public policy initiatives and maintain compliance with legislative and regulatory requirements.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 9: Other Capital Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Other Capital	17.4	4.6	12.8	12.6	7.7	6.3	7.0	8.7	10.3	12.0

Other Capital includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") which are required during the execution of capital programs in the 2025-2029 rate period.[43]

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 10: System O&M Expenditures: 2020-2029($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

System O&M expenditures are expected to increase at an average annual rate of approximately 3 percent between 2025 and 2029. The increases are driven by a number of factors:

- Toronto Hydro is expanding inspection and maintenance activities in key areas through the Preventative and Predictive maintenance programs, resulting in an 11 percent increase between 2024 and 2025, followed by a moderate 1 percent average annual increase from 2026-2029. Starting in 2025 Toronto Hydro is adjusting inspection cycles for wood poles from ten years to eight years to manage failure risk driven by wood pole age and condition demographics. Toronto Hydro will also begin inspecting concrete and steel poles as part of its Pole inspection program on a ten-year cycle. Toronto Hydro will transition to a minimum six-year maintenance cycle for overhead switches, which represents an increase from the current variable cycle, which is generally greater than six years. Toronto Hydro will continue to ramp up the Cable Diagnostic testing segment in Preventative and Predictive Underground Line Maintenance program, collecting key condition information on a greater

[43] As discussed in Section E4.1.5, Road Cut Restoration costs and Major Tools are attributed directly to capital program expenditures and are not included in Table 7.

number of feeders to inform both short- and long-term investment decisions. The introduction of incremental inspection activities at DER sites and increasing volume of Energy Storage locations within the Preventative and Predictive Stations program also drive cost increases. Toronto Hydro plans to reduce its Network Vault civil inspection program starting in 2027 as a result of the implementation of Network Condition Monitoring and Control resulting in reduced costs in that program. The large majority of Toronto Hydro's inspection and maintenance programs are cyclical in nature, with cycles established to meet regulatory requirements, as discussed in Exhibit 2B, Section D3. As a result, significant reductions to inspection or maintenance programs are not expected in the 2025-2029 period. Differing volumes of work and inflationary impacts will result in year over year fluctuations in expenditures between 2025-2029 within these programs;[44]

- The Corrective Maintenance program expenditures increase by 14 percent between 2024 and 2025, followed by a 3 percent average annual increase from 2026-2029. The increase in the Corrective Maintenance Program is driven by the need to address a growing backlog of P3 deficiencies within the system. Expected expenditures related to increasing spot tree trimming and corrective work for DER sites also drive an increase in this program. For more details, please see Exhibit 4, Tab 2, Schedule 4;
- A 12 percent increase between 2024 and 2025 is forecasted within the Emergency Response program. Inflationary pressures including increased labour and vehicle costs for services and a new contract for external resources that will be effective in 2025 contribute to the increase. From 2026-2029, expenditures align to a 2 percent average annual increase;[45]
- The Supply Chain program is growing by 14 percent between 2024 and 2025 followed by an average annual increase of 6 percent between 2026-2029. The increase in costs is primarily due to higher payroll and contract costs required to support an expanded Capital Program within a more complex global supply chain environment;[46]
- The Asset and Program Management program will have an average annual increase of 6 percent over the 2025-2029 rate period driven primarily by higher payroll and external contract costs to support an expanding capital and maintenance program and the expansion of the Grid Modernization function. This function will allow the utility to forecast, understand, and manage a more complex system as it becomes increasingly decarbonized,

[44] Exhibit 4, Tab 2, Schedules 1-3.
[45] Exhibit 4, Tab 2, Schedule 5.
[46] *Supra* note 38.

decentralized, and digitized. Incremental resources, new skillsets, and third-party support is required within the planning and engineering functions in support of the above needs;[47]

- The Work Execution program will have an average annual increase of 5 percent over the 2025-2029 rate period. The growth in this program is driven directly by the need for additional headcount to support a growing capital and maintenance program with increasing complexity to support the energy transition. The increase in headcount in key Certified and Skilled Trades and Designated & Technical Professional positions is required to enable internal work execution, whereas key resources such as field, project, and contract managers are required to support external work execution. Increases in training costs, tools and safety equipment, and personal protective equipment ("PPE") are also required;
- In addition, increasing resource and skill requirements and capabilities to support grid modernization results in higher costs across various business functions. For example, increasing the workforce of Control Centre Operations will be crucial as Toronto Hydro expands its grid and modernizes system operation through more sophisticated data analysis and automation, which will require more staff both to handle increasing volumes of work and deploy specialized skills and knowledge made necessary by the evolution of operational systems; and
- Inflationary pressures are also a key contributor to increasing expenditures over the forecast period across the various System O&M programs.

[47] *Supra* note 37.

E4.2.7 Forecast Construction Work in Progress ("CWIP")

Table 11 below provide the 2025-2029 CWIP. Detailed explanations for capital expenditures are provided above and explanations for variances in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 11: Forecasted 2025-2029 CWIP ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening CWIP	456.4	536.3	595.1	622.7	681.7
Additions (CAPEX)	725.8	758.1	823.2	828.2	812.3
Deductions (In Service Additions)	(645.9)	(699.4)	(795.6)	(769.2)	(875.4)
Closing CWIP	536.3	595.1	622.7	681.7	618.6

Note: Variances due to rounding may exist

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 356.2	**2025-2029 Cost ($M):** 476.5
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load connections and distributed energy resources ("DER") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2022, Toronto Hydro completed 99.9 percent of low voltage (below 750 V) and 99.1 percent high voltage (750 V or above) connections on time, a performance improvement from 2018 of 1.6 percent for low voltage connections and 0.8 percent for high voltage connections. In 2022, 92.4 percent of DER connections were connected on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers; and

[1] EB-2018-0165, Exhibit 2B, Section E5.1
[2] These metrics are published in Toronto Hydro's 2022 Scorecard; See: https://www.oeb.ca/utility-performance-and-monitoring/scorecard/600/view

- **Generation Connections**: This segment involves connecting DER customers to the distribution system.

The investments made by Toronto Hydro in this Program support the ongoing economic growth and development in the City of Toronto.[3] The connection of DER facilities under this Program supports the achievement of the public objectives with respect to facilitating innovation and supporting DER integration within Ontario's electricity system and the Ministerial directive issued by the Minister of Energy on October 21, 2022.

E5.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro customer focus objectives by: ○ Fulfilling customer service requests as mandated by Sections 6.2.4 (generation connections) and 7.2 (customer connections) of the Distribution System Code ("DSC"), Electricity Act, 1998 (Electricity Act), and Ontario Energy Board Act, 1998 (OEB Act); and Toronto Hydro's Conditions of Service and Electricity Distribution License; ○ Completing low and high voltage connections within five and ten business days respectively at least 90 percent of the time, as measured pursuant to the OEB's connection metrics and section 7.2 of the DSC; ○ Completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics, 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and ○ Responding to inquiries requiring a written response within ten business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC. ○ Connecting DER facilities to the distribution system as mandated by sections 25.36, and section 26 of the Electricity Act, 1998; and; without extensive delays or adverse impacts to existing customers, within 5 business days at least 90 percent of the time on a yearly basis as per section 6.2.7 of the DSC.

[3] City of Toronto, Toronto Official Plan, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/ ; City of Toronto, City Planning Development Pipeline 2021, "online", https://www.toronto.ca/wp-content/uploads/2021/06/963e-Development-Pipeline-2021.pdf; Waterfront Toronto, Integrated Annual Report 2021-2022, June 23, 2022, "online", https://www.waterfrontoronto.ca/sites/default/files/202207/Waterfront%20Toronto%20Integrated%20Annual%20Report%202021-2022.pdf

Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system
Operational Effectiveness - Safety	• Contributes to compliance with Electrical Distribution Safety (O. Reg 22/04) and safety objectives by: ○ Ensuring service connections are compliant with applicable requirements; and ○ Ensuring Electrical Safety Authority connection permits are available prior to connecting new or upgraded customers' service entrance equipment.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request.

E5.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

E5.1.3.1 Load Connections

The Load Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system and service upgrades for existing customers. Toronto Hydro has seen an increase in the volume and complexity of customer connections due to ongoing growth and development in the city, larger connections (e.g. for data centres, transit etc.) and the energy transition. Densification and growth in the City of Toronto, including increased residential and commercial developments as well as mass transit system growth, are fundamental drivers for the increased volume of work in the Load Connections segment, as many, if not all, new developments will require new or modified connections to Toronto Hydro's distribution system. The energy transition is also an important driver of the Load Connections segment as customers look to the electricity grid to meet more of their energy needs. Toronto Hydro anticipates that the number of customer service requests and the size of the requested connections will continue to trend up to accommodate growing residential and commercial needs. Toronto Hydro has a legal obligation, pursuant to section 28 of the *Electricity Act*, to fulfill these service connection requests or to make an offer to connect ("OTC") for any customers in its service area.[4]

Toronto continues be one of the fastest growing cities in North America. Serving this growing city, Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year. Toronto currently has 238 construction cranes operating, 4.7 times as many as the next most active city, Seattle.[5] From 2017 to 2022, the city's development pipeline included 2,413 projects in various stages of approval and completion as shown in Figure 1 below.[6] Toronto Hydro anticipates that a large number of projects and proposed loads submitted between 2017 and 2022 are expected to be completed within the 2025-2029 period or shortly thereafter based on the average completion rate and the number of units proposed for the City of Toronto.[7] Thus, Toronto Hydro expects that the current rate of development will continue over the 2025-2029 period. These projects in the development pipeline represent a City record of 717,327 residential units and 14,484,961 square metres of non-residential gross floor area, the highest development volumes for any five-year period the City has reported on to date. The pace of development in Toronto could increase even further with the recent passage of the *More Homes Built Faster Act, 2022*[8] by the Government of Ontario. This act is intended to expedite the approval of development projects and provide new tax incentives and funding mechanisms aimed at encouraging development. Toronto Hydro will continue to monitor the impact of this legislation on the distribution system.

[4] Subject to certain exemptions as set out in the Distribution System Code, including Section 3.1.1 of the Distribution System Code ("DSC")
[5] Rider Levett Bucknall (RLB), Crane Index® for North America, Q1 2023, "online", https://www.rlb.com/americas/insight/rlb-crane-index-north-america-q1-2023/
[6] Including projects that are pending approval, approved, awaiting or holding building permits, or under construction - The 2413 pipeline projects breakdown is 622 built, 879 active and 912 under review: Toronto City Planning, Profile TO, Development Pipeline 2022 Q2, "online", https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[7] Discussed further in the Load Demand program, see Exhibit 2B, Schedule E5.3.
[8] Bill 23, More Homes Built Faster Act, 1st Sess, 43rd Parl, 2022, https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Figure 1: Proposed Projects in the City of Toronto (2017-2022)

In addition to volume of projects, Toronto Hydro also anticipates that there will be a greater need for larger and more complex connections. There has a been a substantial increase in larger commercial and multi-use projects requiring greater than 10MVA of demand load per project, and data centres requiring larger loads than previously required from Toronto Hydro. In addition, the city is experiencing a period of unprecedented expansion of electrified public transportation requiring large new load connections to Toronto Hydro's distribution system (e.g. Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line).[9]

Furthermore, the City is experiencing a shift to clean energy, and electrification through the adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and water heaters. As the adoption and demand of such technologies continues to evolve and grow, the demand for access to Toronto Hydro distribution system must be leveraged to support these demands. Immediate growth areas being supported by Toronto Hydro's distribution system include electric vehicle charging for: public streets, City fleet vehicles (including TTC), Toronto Parking Authority parking lots, residential homes, commercial and residential developments. Ongoing and other evolving areas include heating/cooling systems (heat pumps), and complete home electrification at single-family residential home and residential complex levels.

[9] Further details can be found in Exhibit 2B, Schedule E5.2

This pace of development and growth is consistent with the City's projected growth in population, which is over 2.97 million as of July 2021 and is expected to continue to increase into the future.[10] Since the City of Toronto is bounded, accommodations for population growth and needed support systems (residential, retail, commercial, multi-use, institutional, transit developments), including access to Toronto Hydro's distribution system to support population growth, will intensify as the population increases.

As illustrated in Figure 2, from 2012 to 2022, Toronto Hydro connected approximately 76,000 customers, representing a 11 percent increase in its customer base (average of 1.0 percent per year), and approximately 20,000 customers from 2018 to 2022, representing a 2.6 percent increase (average of 0.7 percent per year). Similar levels of growth are expected for the 2025-2029 period, as described in the Customer Forecast Section.[11] These additional customers were connected to Toronto Hydro's distribution system as a result of the investments in the Load Connection segment.

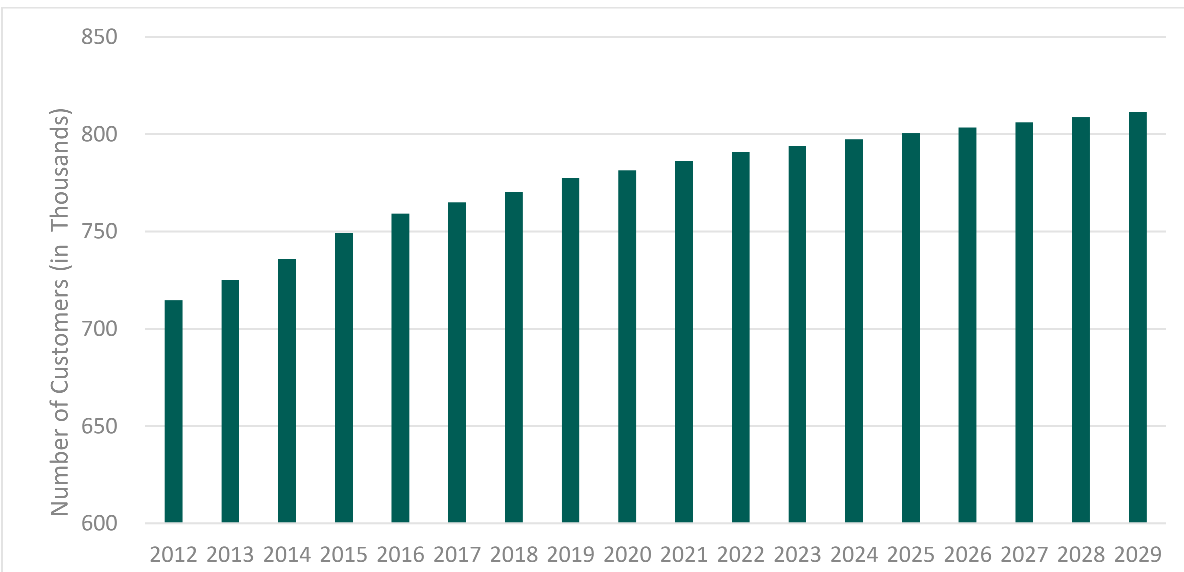


Figure 2: Historical and Forecast Number of Toronto Hydro Customers

10 Province of Ontario, Ontario Population Projections, "online", https://www.ontario.ca/page/ontario-population-projections#chart8;
The greatest growth is expected in the areas of: City of Toronto, 2021 Census, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf
For the period 2016 to 2021, the districts of Spadina-Fort York, Toronto Centre, Etobicoke-Lakeshore, and Toronto-St Paul's have shown the greatest growth in population at growth in populations of 17.9%, 15.5%, 9.8%, and 8.4% respectively

11 Exhibit 3, Tab 1, Schedule 1.

Customer connections can be in the form of a basic connection, or a connection requiring expansion work. Each new or upgraded service connection must meet the individual needs of the customer. This includes customer specific type, size, required demand load, geographical location of the customer's site, geographical availability of Toronto Hydro's distribution system in relation to the customer's site, and available distribution system infrastructure and capacity provisions.

The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

- **Low voltage connections (below 750 Volts) ("LV"):** These connections primarily involve residential and small commercial customers (GS<50 rate class) supplied at 750 Volts or less whose average monthly maximum demand is less than, or is forecasted to be less than 50 kW. The number of connections remains high at over 2000 connections per year for the period of 2020-2022. This work is typically seasonal and has a relatively short turnaround time. As part of Toronto Hydro's obligations, the utility works with customers to provide options for a new connection or service upgrade. As per the DSC, section 7.2.1, these service requests must be completed within 5 business days from the day on which all applicable service conditions are satisfied. or at a later date as agreed to by the customer and distributor; and
- **High voltage connections (750 Volts and above) ("HV"):** These connections primarily relate to larger residential and commercial developments. These customers typically engage Toronto Hydro years before service is expected to be required. Figure 3 provides a year-over-year comparison of the volume of new formalized high voltage requests that Toronto Hydro receives on an annual basis. High voltage connections increased by 27.6 percent for the period 2020 to 2022. As per section 7.2.2 of the DSC, these service requests must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

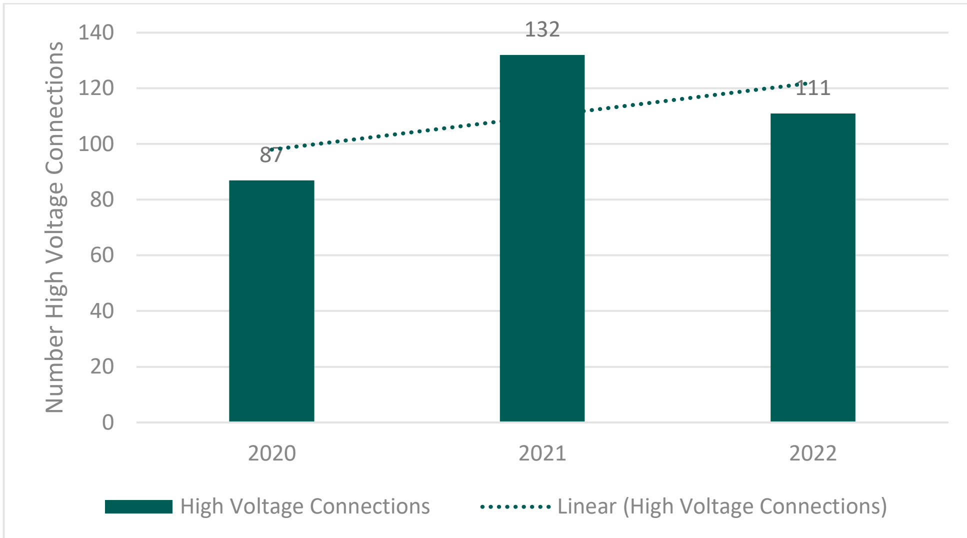


Figure 3: High Voltage Connections 2020-2022

For both low and high voltage service connections, applicable service quality requirement must be met at least 90 percent of the time on a yearly basis.

Toronto Hydro continues to process a high amount of feeder requests[12] at over 800 per year, and has experienced a 29.8 percent increase in feeder requests since 2020. In 2022, Toronto Hydro processed 1055 feeder requests, the highest volume to date. The overall increasing trend in the volume of requests processed from year to year is expected to continue up to and throughout the 2025-2029 period. Following a feeder request, the connection typically materializes within five years, from the day the feeder request was created, excluding any project delays. As a result, the number of feeder requests received between 2021 and 2022 are expected to drive work in the 2025-2029 period.

[12] **Feeder request**: An internal request to determine the appropriate point and method of connecting customers exceeding 50 kW to Toronto Hydro's distribution system. Feeder requests relate to both potential and proposed projects in their preliminary stages.

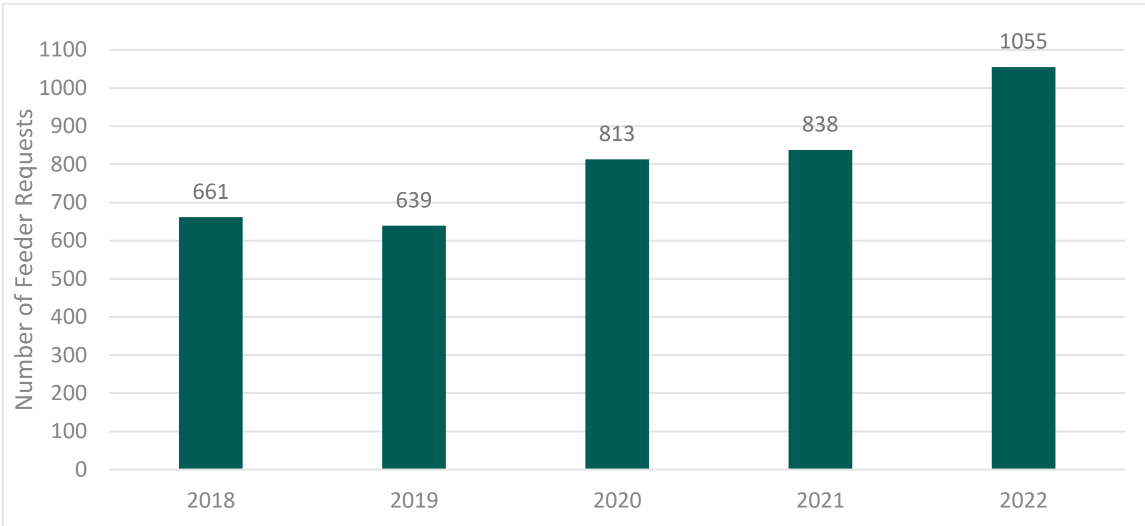


Figure 4: Feeder requests processed (2018-2022)

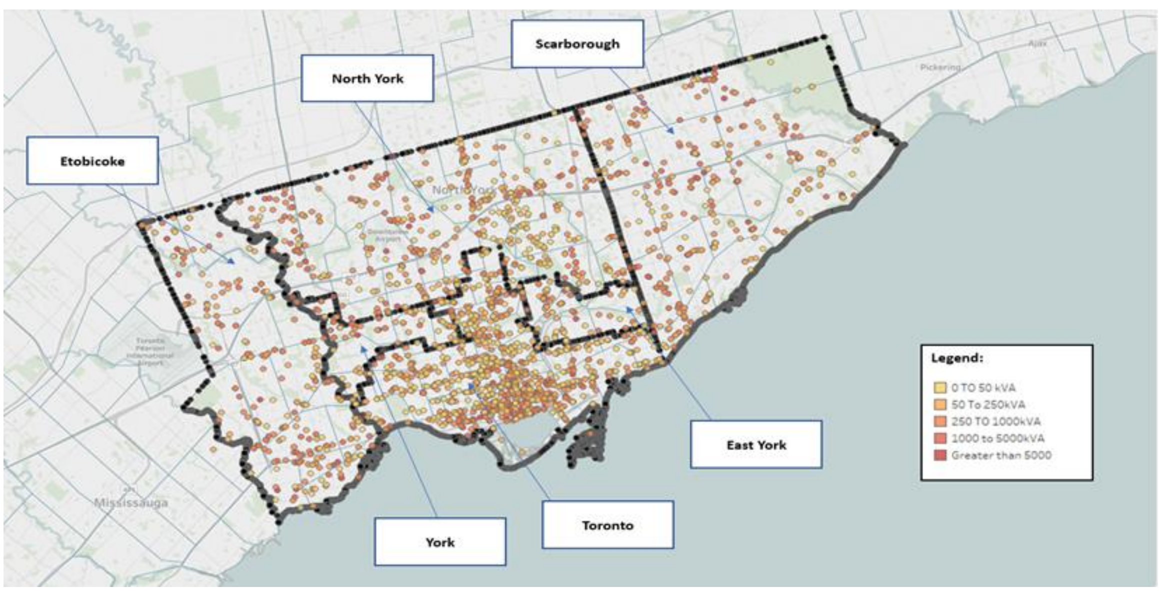


Figure 5: Load Additions in the City of Toronto during the 2018-2022 Period

Similar trends were observed in the overall increasing volumes of Offers to Connect (OTCs) issued requiring expansion work throughout the 2019 to 2022 period, as illustrated in Figure 6*.* The number of Offers to Connect (OTCs) between 2020-2022 has already exceeded 68 percent of the total volume count of OTCs for the five-year period 2015-2019. Expansion work is typically needed for larger connections or requests in areas of the City that are capacity constrained. This involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure required to accommodate new customer loading. Such work can have a significant cost impact as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large-scale and complex, and thus require weeks or months to complete. Connecting customers to the distribution system without completing the necessary expansions can negatively impact system reliability and safety.

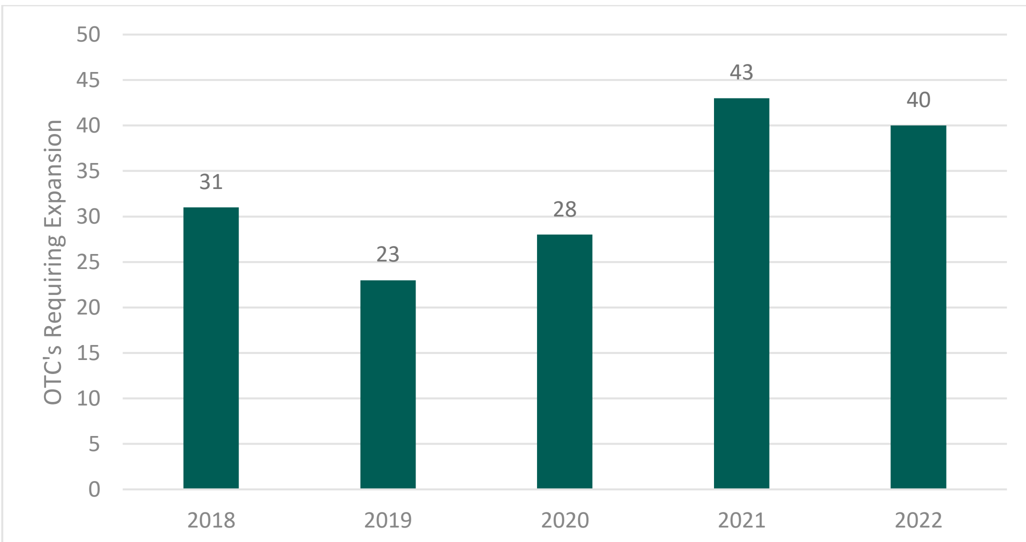


Figure 6: Offers to connect Requiring Expansion

E5.1.3.2 Generation Connections

As per section 25.36 of the *Electricity Act*, Toronto Hydro is mandated to connect renewable DER while maintaining the safety and reliability of the system for existing customers. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system and to provide access for renewable energy generation facilities. Under Section 6.2 of the DSC, for all types of DERs, Toronto Hydro has an obligation to enable and connect the DER. Toronto Hydro must balance its obligations to prospective and existing DER connections with its responsibilities to maintain a safe and reliable distribution system for its load customers. When connecting and assessing DER facilities, Toronto Hydro is also required to meet certain timelines:

- Based on OEB's recently released Distributed Energy Resources Connection Procedures (DERCP) document, the distributor must complete and provide a Connection Impact

Assessment (CIA) with cost estimates within 60 days[13] of receipt of substantially complete application for small and mid-sized DER where no system reinforcement or expansion work is required, and within 90 days where either the DER is large or system reinforcement or expansion work is required; and

- A distributor, as per sections 5.3.13 and 5.3.14 of the DERCP, shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor 90 percent of the time on a yearly basis.

Toronto Hydro supports connecting DER to the distribution system in alignment with the DERCP and in coordination with Hydro One and the IESO. As of the end of 2022, Toronto Hydro connected 2,424 DER connections from customers and developers under a variety of technologies and applications with a total connected capacity of 304.94 MW. These can be broken down into three (3) different categories as shown in Table 4 below:

- **Renewable:** consists of DER based on renewable technologies, such as solar photovoltaic, wind turbine and bio-gas generators;
- **Energy storage:** refers to DER related to the capture of energy, such as batteries and underwater compressed air; and,
- **Non-renewable:** refers to conventional fossil-fuel based DER, such as natural gas generators and combined heat and power ("CHP").

1. Existing Generation Connections

An overview of the number and total capacity of DERs and their distribution across the city are provided in Table 4, Table 5 and Figure 7.

Table 4: Cumulative Existing Generation Connections by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	1296	1547	1749	2072	2094	2126	2185	2280
Energy Storage	1	4	4	10	11	22	24	28
Non-Renewable	35	38	44	54	60	87	112	116
Total	**1332**	**1589**	**1797**	**2136**	**2165**	**2235**	**2321**	**2424**

[13] Ontario Energy Board, Distributed Energy Resources (DER) Connections Review, "online", https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/distributed-energy-resources-der

Table 5: Cumulative Existing Generation Capacity (in MW) by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	71.9	86.6	96.6	108.7	110.0	111.3	114.1	116.2
Energy Storage	0.7	0.7	0.7	4.5	9.1	17.6	18.2	18.7
Non-Renewable	91.9	98.4	114.4	119.6	127.7	157.4	169.5	170.0
Total	**164.5**	**185.6**	**211.6**	**232.8**	**246.8**	**286.3**	**301.8**	**304.9**

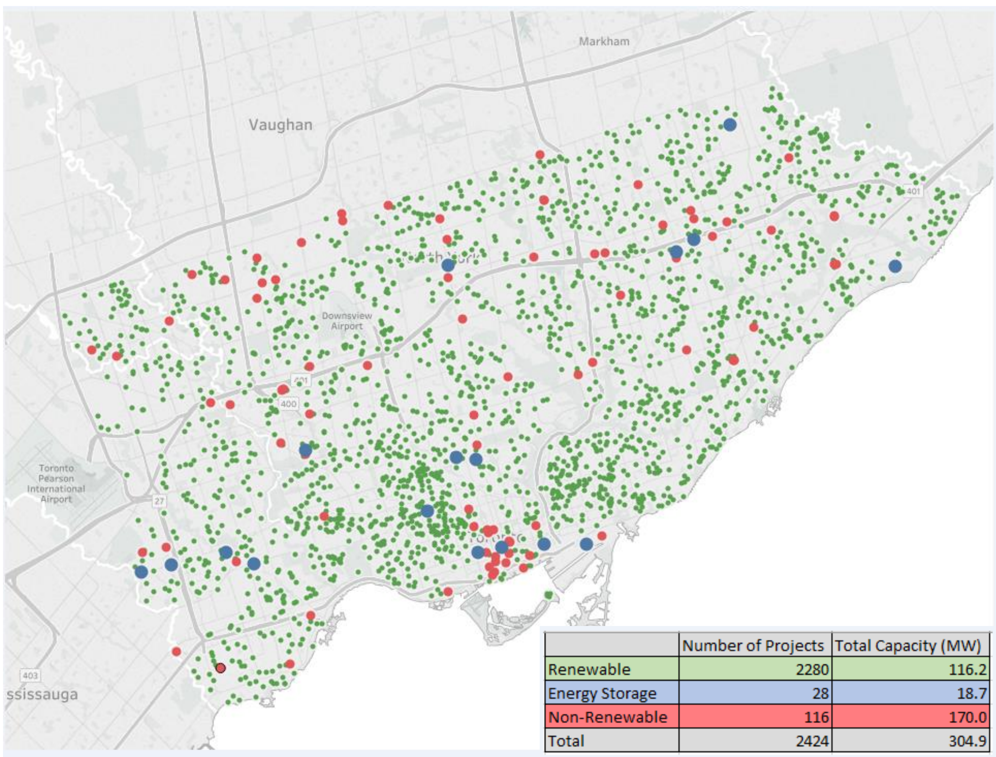


Figure 7: Generation Connections in Toronto Hydro Service Area by Generation Type

Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease with a 71.9 percent decline in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Tables 4 and 5 show increases across all categories of DERs. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With recent regulatory and public pressures towards clean energy, it is possible that the combined installed capacity for renewable and energy storage based DER's could surpass non-renewable in this next rate period.

a. Renewable DER Connections

Since the FIT program ended in 2018, Net Metering has become the predominant program choice for connecting renewable generation. Net Metering financially compensates customers through bill credits for any excess electricity generated to the grid at the going rate for electricity. However, the financial benefit is generally less lucrative when compared with the FIT program. While interest in Net Metering continues to grow, pre-assessment and connection applications under this program are lower by comparison to the years when the FIT program was active. Still, since 2018, Net Metering pre-assessments had an average annual growth of 36 percent between 2018 and 2022. In 2022, a total of 362 pre-assessments were completed along with 95 connections, both record highs for this program in the midst of the COVID-19 pandemic.

b. Energy Storage Connections

There has been a relatively low number of energy storage connections in Toronto to date; with only 28 connected projects as of 2022. However, Toronto Hydro's current Energy Storage project pipeline anticipates the connection of an additional 12 projects worth 31.9 MW by the end of 2023. Some of these projects include large battery systems being installed at various Metrolinx and Toronto Transit Commission (TTC) stations used for light-rail transit and hybrid bus charging. The relatively large pipeline in 2023 can be partially attributed to the advancement of projects that had been delayed in earlier years as a result of the COVID-19 pandemic.

c. Non-Renewable DER Connections

In 2018, Toronto Hydro saw significant interest in non-renewable generation with pre-assessment applications increasing to 124 from 61 the previous year. In 2019 however, pre-assessment applications declined to only 35 for non-renewable DER and have continued to fall with only 5 requested in 2021. A similar trend can be observed with CIA applications reducing from 25 to 4 between 2020 and 2021. The timing of this decrease coincides with changes made to the IESO's Process Systems & Upgrade (PSU) program, originally introduced by the IESO in 2011, that offered financial incentives for the implementation of energy efficiency and generation projects that are capital intensive.[14] As of May 1st, 2019, IESO made fossil-fueled CHP applications ineligible for incentives under this program.[15] This has led to a notable decrease of non-renewable DER applications. In 2022, only four non-renewable projects were connected, compared to 52 in 2020 and 2021. The increased regulatory and public pressures on companies to move towards cleaner sources of energy generation will likely lead to continued decline in new non-renewable installations.

2. Generation Connection Forecast

Toronto Hydro's DER forecast is separated into renewable, energy storage and non-renewable segments. For each segment, forecast DER capacity was approximated using a mathematical model that best represented recent and anticipated growth patterns, considering a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of forecast.

The DER forecast assumes that no major changes to the current regulatory policy or availability of funding and incentives occur within the forecast period. Furthermore, Toronto Hydro compares its forecast results with other third-party studies and research for alignment.

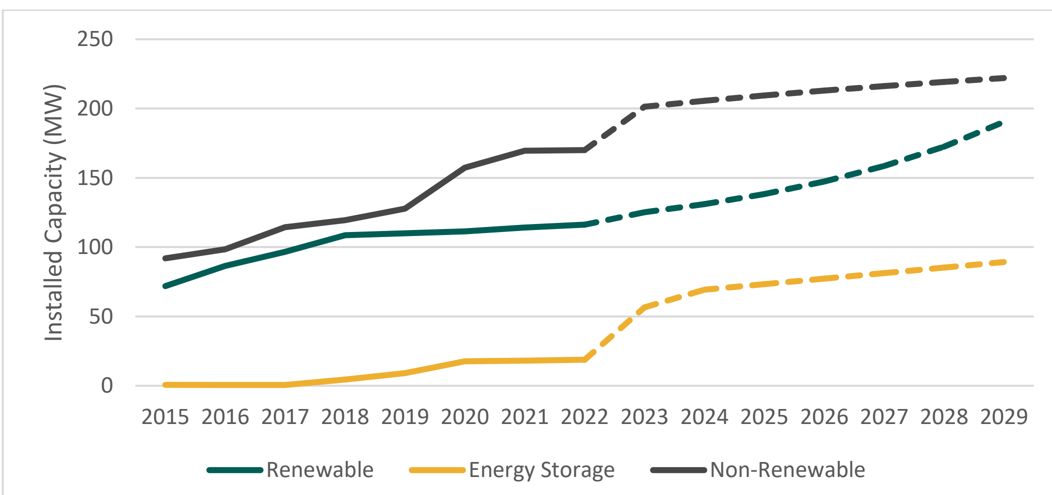


Figure 8: DER Generation Capacity (historical and forecasted) within Toronto Hydro's service territory

[14] Save on Energy, Program Requirements, "online", https://saveonenergy.ca/-/media/Files/SaveOnEnergy/Document-Archive/IF-Documents/PSUP-Program-Requirements-LT.ashx
[15] Independent Electricity System Operator (IESO), New Process and Systems Upgrades Program, "online", https://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/Conservation-E-BLASTs/2019/05/New-Process-and-Systems-Upgrades-Program

a. Overall Forecast

Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching over 4,400 connections by the end of 2029. This represents a total DER installed capacity of approximately 516.7 MW in comparison to the 304.9 MW installed as of the end of December 2022.

Table 6: Forecast Generation Connections

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	2507	2690	2916	3172	3495	3858	4263
Energy Storage	44	47	53	58	66	73	82
Non- Renewable	132	137	139	141	143	145	147
Total	**2683**	**2874**	**3108**	**3371**	**3704**	**4076**	**4492**

Table *7:* Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

b. Renewable DER Connections

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to 200.41 MW. This rate of growth is in alignment with the Ontario DER Impact Study conducted by ICF in 2021.[16]

c. Energy Storage connections

Between 2023 and 2029, Toronto Hydro forecasts over 50 additional Energy Storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed Energy Storage capacity to 89.5 MW. The pipeline projects indicate aggressive growth in energy storage connections between 2023 and 2025. This growth may be attributed to completion of projects deferred earlier during the COVID-19 pandemic.

[16] ICF Ontario DER Impact Study – January 18, 2021

Beyond 2025, Toronto Hydro believes energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. This rate of growth put this forecast above the high-scenario in the Ontario DER Impact Study conducted by ICF in 2021.[17] However, due to the relatively small existing total capacity of Energy Storage currently installed in Toronto, even the connection of a single large project will lead to large statistical percentage increase in the installed base.

d. Non-Renewable Connections

Toronto Hydro's pipeline for non-renewable DER currently consists of eight projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW.

While Toronto Hydro anticipates increased pressure from government and regulatory bodies to reduce the use of non-renewable sources of energy as different net zero emissions targets are approached,[18] the most common applications of non-renewable DERs do not yet have viable or technologically mature alternatives. For example, gas generators remain the preferred method of backup generation in the event of an outage for customers as they can run for longer periods of time when compared with energy storage. Renewable generation is not typically suitable for this purpose as they are dependent on the availability of wind (in the case of wind turbines) and sunlight (in the case of solar PV).

Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity. Currently, projects to make fossil fuel-based CHP systems sustainable are still in the pilot phase,[19] and not available to customers.

e. Renewable DERs Policy Considerations

DER demand is driven directly by customer behaviour and choices, which in turn can be greatly impacted by regulatory policy and the availability of funding and incentives. The FIT program is evidence of the rapid impact policy and incentives can have on the renewable DER segment. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to

[17] ICF Ontario DER Impact Study – January 18, 2021

[18] TransformTO's Net Zero 40 and the Net-Zero Emissions Accountability Act achievement of Net Zero by 2050.

[19] Newswire, Cision Canada, "online", https://www.newswire.ca/news-releases/new-combined-heat-and-power-system-will-reduce-greenhouse-gas-emissions-ghg-and-advance-enbridge-gas-hydrogen-hub-in-markham-ontario-886069080.html

108.7 MW, which represents a compound annual growth rate (CAGR) of 62.2 percent. When the FIT program ended, renewable energy growth reduced to 1.7 percent.

Some current policies and economic factors that may impact the rate of renewable DER and energy storage connections include:

- **Green Energy Tax Credit -** This tax credit, announced by the Federal Government in November 2022, allows a tax credit of up to 30 percent of the capital cost of investments in specific generation systems including solar PV and battery storage systems;[20]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities.[21] It is expected that this policy will increase customer accessibility to renewable generation facilities, given the high initial cost requirement. This has generally been the case in other jurisdictions where this model is well established.[22] While no third-party Net Metering applications have yet been received by Toronto Hydro, Toronto Hydro anticipates that this policy may play a key role in driving renewable DER growth during this period;
- **Low Lithium Ion Battery Cost -** Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[23] The combination of solar PV and energy storage allows users to capitalize on energy that can only be captured during the day, improving the usability of power generated by solar PV. Low battery cost, along with the popularity of the Net Metering program, are likely to result in increased adoption of these technologies;
- **Ultra-Low Overnight Price Plan -** In 2023, the Ontario government launched a new "Ultra-Low" overnight price plan for residential and small business customers. The new ultra-low

[20] Environment and Climate Change Canada, News Release, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

[21] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts, "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net

[22] For example, the Solar Energy Industries Association (SEIA) in the US reported that 83% of residential solar systems installed over the last 4 years in New Jersey from 2017 were third-party owned (https://www.seia.org/initiatives/third-party-solar-financing)

[23] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

overnight rate of 2.4 cents per kWh (down from 7.4 cents)[24] provides further incentive for customers to store energy overnight and discharge during the day and is expected to lead to increased demand for energy storage systems; and

- **Industrial Conservation Initiative (ICI) program -** Large commercial and industrial customers who have opted into the Industrial Conservation Initiative (ICI) program with the IESO can reduce their global adjustment charges through peak shaving or "GA busting" using energy storage systems.

The timing, impact and probability of customer incentives relies on a number of different societal and political considerations and are difficult to predict. While this forecast does not consider future incentives not already announced, it is clear that new incentives can dramatically change the numbers presented here. As different levels of government implement net zero targets, the likelihood of intervention by government and regulatory bodies to support or promote DERs is likely to increase. As such, growth trends of DER could look very different beyond 2029.[25]

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
Program/ Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Customer Connection	36.5	92.5	75.9	71.3	75.7	84.5	90.0	95.4	100.7	106.0
Generation Connection	(0.9)	(0.1)	0.2	-	-	-	-	-	-	-
Total	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**

[24] Province of Ontario, Ontario Launches New Ultra-Low Overnight Electricity Price Plan, "online", https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan
[25] See, for example, the Future Energy Scenarios whereby the total solar PV uptake by 2025 reaches an installed capacity of approximately 430 MW in the low scenario and more than three times that in the high scenario; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* p. 67-70.

Customer Connections Gross	105.6	136.1	139.5	135.1	155.9	167.4	178.9	190.0	201.2	212.3
Customer Connections CC	(69.0)	(43.6)	(63.5)	(63.8)	(80.2)	(82.9)	(89.0)	(94.7)	(100.5)	(106.3)
Net	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, provincial and municipal policies regarding infrastructure, community and land revitalization projects, and the energy transition. As described below, Toronto Hydro's 2025-2029 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations in various industries (such as technology,[26] design,[27] financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures. Factors such as GDP, growth forecasts, inflation, unemployment rates, corporate tax rates, investor protection, purchasing power and credit ratings provide awareness into economic potential and the operating environment. Provincial and municipal policies regarding infrastructure and community revitalization projects (e.g. Toronto Waterfront – Port Lands, Quayside, Parliament Slip, Villiers Island), hospitals, universities, public transit projects (e.g. TTC and Metrolinx - Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line) may give rise to connection work and consequently create further construction and related work in the relevant project sites and surrounding areas;

2) The number, type, size, and location of connection requests received by Toronto Hydro are factors that inform whether an expansion to the distribution system is required. As elaborated in Section 3.1 above, expansion work can significantly impact program

[26] Toronto is a global hub for IT: CBRE, Scoring Top Tech Talent 2022, "online", https://mktgdocs.cbre.com/2299/957e9b99-3410-4f62-b1b1-b4a53147cee1-897668710/2022-Scoring-Tech-Talent.pdf
[27] Toronto employs the largest design workforce in Canada and third largest in North America: CBRE, Tech-30 2022, "online", https://mktgdocs.cbre.com/2299/1d1f0fcb-b1a2-443e-9277-59e1ec6b9cee-609426651/Tech-30-2022.pdf

expenditures as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a customer; and

3) Capacity relief and additional capacity provisions completed under other System Access and System Renewal programs. For example:
    a) Areas with load constraints may be relieved under the Load Demand program- the resulting capacity relief will allow Toronto Hydro to connect customers more efficiently, reducing expansion requirements to the distribution system and consequently reducing connection costs;
    b) Assets replaced to current standards under the Overhead System Renewal program may indirectly include additional capacity provisions for future purposes, including where:

        (i) poles are replaced with higher or stronger poles to accommodate additional circuits without having to replace the new poles in the future; and

        (ii) additional ducts may be installed when ducts are rebuilt to leverage trenching costs and avoid future costs.

Toronto Hydro’s customer charges or allowances associated with connections are established pursuant to the DSC, and Toronto Hydro’s Conditions of Service. Connection asset related work, less any allowance, is paid for by the customer. Expansion asset related work is evaluated using the Economic Evaluation Model[28] to determine capital contribution and expansion deposit requirements to be met by the customer.

For the next rate period, Toronto Hydro proposes to increase its Basic Connection Fee allowance for Rate Class 1 to 5 from $1396[29] to $3059. The Basic Connection Fee has not been updated since 2009. The updated Basic Connection Fee reflects the cost of the current connection standards and includes upgraded transformation from 100kVA, to 167KVA. The upgraded transformation standard will reinforce the current overhead system and reduce barriers to electrification by supporting increased load from EV charger installation and/or home electrification. In addition, the increased allowance will also make new service connections more affordable for new residential homes.

[28] As defined in Section 3 and Appendix B of the Distribution System Code (“DSC”).
[29] Fees are reviewed annually and updated with notice to customers when Toronto Hydro’s Conditions of Service is revised.

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 48 percent). The average capital contribution rate for years 2020-2022 was 47.7 percent. In order to smooth any cyclical trends and better reflect actual contributions, the 2025-2029 forecast for contributions was developed by considering the average capital contribution experienced during the most recent 5-year period (i.e. 2018 to 2022) and projecting year by year specific contributions for 2025-2029 yielding an average capital contribution rate of 49.8 percent an increase of 3.7 percent above the previous filing rate.

For the 2020-2024 period, the load connection segment is forecasted to be 1.75 times the gross expenditures initially planned. As described above, recovered capital contributions were consistent with the planned ratio of 48 percent. As will be explained below, the increase in expenditures is largely attributed to a substantial increase in projects greater than 5MVA and 10MVA of demand load.

For 2021-2022 Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (>= 5MVA demand load). In that time, Toronto Hydro connected three times more incremental demand load for >= 5MVA projects than for the entire proceeding five-year rate period 2016-2020 and almost 8.7 times more incremental demand load for projects >=10MVA.

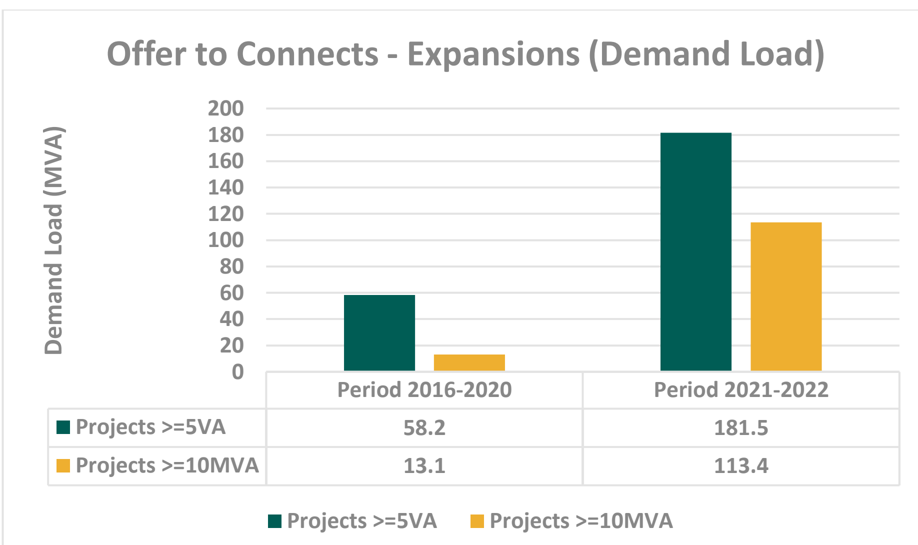


Figure 9: Offers to Connect – Expansions (Demand Load)

The increases in 2020-2021 were attributed to the emergence of unforeseen large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). This market trend towards larger projects seeking system access is expected to continue at 2021-2022 levels through to 2024 based on the current feeder request pipeline, ongoing pre-offer to connect customer design discussions and demand load requirements. Based on Toronto Hydro's early development and Key Accounts initiatives, and direct consultation with customers, Toronto Hydro determined that planned developments for the 2025-2029 timeframe include approximately 17 to 20 projects with greater than 10MVA of demand load. These projects are progressing through the City of Toronto pipeline and development application process, drawing and review phases.

Additionally, the energy transition to clean energy, and electrification has begun creating increased demand for access to the distribution system to support customer adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and electric water heaters. The increasing access requests have developed through numerous channels (Key Accounts relationships, direct customer requests, and consultant/contractors on behalf of customers) and it is expected to grow as energy transitioning matures. Identifiable EV specific projects over the 2022-2024 period include the City of Toronto on street parking project (30 locations with 53 charging ports – 2023), Toronto Parking Authority off street parking (including over 100 EV ground level charging station installed, and 47 pole-mounted stations – 2022, and 225 ground level stations in 2023). This rate of electrification within the City of Toronto is expected to grow and increase rapidly throughout the 2024-2029 period together with ongoing new building construction electrification requirements for commercial, residential and mixed-use developments.

Looking forward to the 2025-2029 period, it is forecasted that the large project (excluding data centres) segment growth will continue to grow at the same or higher levels than the 2020-2024 period. In particular, as discussed above, large projects requiring greater than 10MVA of demand load is expected to grow from one project/year (2020-2024) to approximately three to four projects per year (2025-2029) with an average incremental total demand load of 65MVA per year. Projects during this period are expected to include loading profiles which also encompass compliance with EV charging requirements. These projects are primarily comprised of large multi-use community building developments throughout the City.

Major transit projects for 2025-2029 are also expected to exceed levels experienced and expected for 2020-2024 (one to two projects for the period), and includes projects for the Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, and the Ontario Line for a total incremental demand load of approximately 150MVA over the 2025-2029 period which is approximately ten times the expected level for 2020-2024.

Based on early development and Key Account initiatives, and direct customer consultations, it is forecasted that the number of data centre service connection for the 2025-2029 period will remain the same as for the 2020-2024 period (total of three for a total incremental demand load of 107MVA), but that the data centres forecasted for 2025-2029 are larger and more complex approximately doubling the incremental demand load expected to approximately 207MVA.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, considering the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 10: Historical & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
Program/Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation Connections Gross	0.8	(1.9)	(0.7)	-	-	-	-	-	-	-
Generation Connections CC	(1.7)	1.8	0.9	-	-	-	-	-	-	-
Net	**(0.9)**	**(0.1)**	**0.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

All project expenses and operational costs for Toronto Hydro to facilitate the DER connections are recovered from the customer through capital contributions.[30] The $0.9 million and $ 0.01 million losses incurred between 2020 and 2021 were due to changes in financial bookkeeping practices that led to discrepancy between expenditures and capital contributions in those years.

Toronto Hydro does not propose any net expenditure under this Program for the years 2025 to 2029. If during the course of the project, Toronto Hydro does not use all of the fees collected from the customer to facilitate the DER connection, Toronto Hydro will refund the difference back to the customer.

Table 11 and Table 12 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 11: 2020-2024 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Renewable <50 kW	24	51	85	170	157	**487**
Renewable > 50 kW	8	8	10	57	26	**109**
Micro Energy Storage	-	-	3	2	2	**7**
Small Energy Storage	9	2	1	2	1	**15**
Mid Energy Storage	2	-	-	9	1	**12**
Large Energy Storage	-	-	-	2	1	**3**
Small Non-Renewable	25	22	4	9	1	**61**
Mid Non-Renewable	1	3	-	7	1	**12**
Large Non-Renewable	1	-	-	-	-	**1**

[30] Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

Table 12: 2025-2029 Volumes (Forecast)

Generation Type	Forecast					Total
	2025	2026	2027	2028	2029	
Renewable <50 kW	179	202	259	293	325	**1258**
Renewable > 50 kW	47	54	64	70	80	**315**
Micro Energy Storage	2	3	4	4	6	**19**
Small Energy Storage	1	1	1	1	1	**5**
Mid Energy Storage	1	2	2	2	2	**9**
Large Energy Storage	-	-	-	-	-	**0**
Small Non-Renewable	1	1	1	1	1	**5**
Mid Non-Renewable	1	1	1	1	1	**5**
Large Non-Renewable	-	-	-	-	-	**0**

Toronto Hydro has a dedicated DER team that supports DER connections. This team works closely with customers to ensure the DER connection process is followed and timelines set by the Ontario Energy Board are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work for a customer service connection as set out in an OTC, the utility will include the additional system growth distribution work (which can range from installing larger circuits to rebuilding cable chambers) as a part of the project but not allocate these costs to the customer's OTC for the service connection. Such additional infrastructure upgrade project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for revitalisation projects such as the Port Lands. The development areas of the Port Lands (e.g. Villiers Island, Polson Quay and South River, McCleary District, Hearn Generating Station, Maritime Hub, Media City, East Port, South Port) includes residential, commercial, retail, and industrial land uses, combined with green space and community-based developments.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal provincial, or federal government agencies. For example, Toronto Hydro is coordinating the expansion work for the Port Lands Revitalization Project with the City of Toronto's road allowance infrastructure construction schedule, as well planning for the Downsview park lands (City of Toronto/Canada Lands) development including servicing and infrastructure.

Where an expansion overlaps with a capital work program or another project, Toronto Hydro would connect customers under a temporary arrangement until the project is complete.

For Generation Connections, the cost for Toronto Hydro to facilitate DER connections are recoverable through customer paid fees resulting in zero net expenditures. These fees are regularly re-evaluated by Toronto Hydro to ensure that they recuperate all connection costs considering various factors like equipment cost changes, market inflation, etc.

E5.1.5 Options Analysis

E5.1.5.1 Option 1: Do Nothing

Do nothing is not an option as Toronto Hydro would be violating the DSC as well as its Distributor License.

E5.1.5.2 Option 2 (Selected Option): Customer Connections Program

As customers request access to the distribution system, Toronto Hydro endeavours to connect them in the most efficient and economic means available. Specifically, Toronto Hydro aims to connect customers from the closest access points available; where possible.

Depending on the system and customer conditions (e.g. requirements, size, location, and timelines), capacity or access may not be available. In such cases, Toronto Hydro will consider alternative solutions to connect the customer. Such alternatives may include, but are not limited to, transferring existing customers to an alternative feeder to free capacity on the feeder in question, or upgrade, extend, or install feeders, transformers, switches or other relevant equipment, as required. Should multiple options exist to connect a customer, options are reviewed with the customer and any differences (financial or technical) are explained to the customer to allow for an informed decision.

The Customer Connections program is an integral program for Toronto Hydro for the purposes of meeting customer service requests in accordance with its mandated service obligations. Without this Program, Toronto Hydro will not be able to serve and connect customers in the manner specified by its Distributor Licence and other applicable regulatory requirements.

E5.1.6 Continuous Improvement

E5.1.6.1 Productivity

In 2022, as part of a continuous improvement initiative to enhance the customer experience, Toronto Hydro created two new teams – the customer intake team and the pre-design team to streamline the customer connection process:[31]

- The customer intake team creates a single point of contact for all customer inquiries related to connections; and,
- The pre-design team acts as a single point of contact for customer to ensure all information required by the design team for large connections is collected before moving forward to the design phase.

At the end of 2023, Toronto Hydro is expected to launch the Service Request Form Enhancements on the Customer Connections portal. These enhancements will improve the customer experience by enhancing the service request form for customers to request new and existing connections from Toronto Hydro. Further details of these initiatives are described in Exhibit 4, Tab 2, Schedule 8.

To improve the customer experience and help customers better understand the availability of different service types and options, Toronto Hydro has prepared a set of public-facing brochures and guidelines. Brochures topics include “How to Power up your Home”, “How to power up your Projects”, pool clearance and underground clearance.

[31] Further details regarding these two teams can be found in Exhibit 4, Tab 2, Schedule 10.

E5.1.7 Execution, Risks & Mitigation

E5.1.7.1 Execution

Customer Connections involves the installation of connection, expansion, and/or enhancement assets, as defined by the DSC. The utility manages the work required under the Customer Connections program for Toronto Hydro. Customers or their representatives are required to consult with Toronto Hydro concerning the availability of supply, supply voltage, service location, metering, and any other details necessary to establish service.

Customers apply for new or upgraded electricity services and temporary power services in writing. Each customer provides Toronto Hydro with sufficient lead-time to ensure the timely provision of adequate electricity supply. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service.

Pursuant to the applicable provisions of the DSC and its Conditions of Service, Toronto Hydro does not connect customers if it has safety concerns or reason to believe that the connection would affect the reliability of its distribution system. A load analysis is performed for each customer request to ensure that the requested connection would not overload Toronto Hydro assets above their rated capacity. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place and to avoid damage to equipment and potential safety risks.

During the consultation and design phase of a customer’s request, if a connection could potentially degrade the reliability of the relevant feeder or station, expansion work is deemed necessary to increase capacity or transfer load so that the current level of reliability is maintained.

Toronto Hydro provides customers with an OTC within 60 days from the day all required information is received. The customer is presented with a job quotation or a “short form” OTC, should the connection not require any expansion. Otherwise, the customer is provided with a “long form” OTC.

Customers are required to accept and make all OTC payments within 60 calendar days of receiving the OTC. Once an OTC is executed, the resulting work is to be carried out by Toronto Hydro resources unless the customer pursues an alternative bid where allowed by the OTC.

E5.1.7.2 Risks & Mitigation

The following are a number of risks that may affect the completion of the Program, and associated actions aimed to eliminate or manage such risks:

- **Capacity upgrade requirements**: Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. Typically, these expansions have long lead times that could present a challenge to Toronto Hydro in meeting the customer's required timelines for connection. The increasing complexity of connections, which may require additional capacity/equipment from Hydro One, may not allow Toronto Hydro to deliver an OTC within 60 days. Toronto Hydro will continue to:
    - Use long term forecasting, including analysis of city area and development plans in order to address growth early on and proactively upgrade or install required assets through enhancement work to the system;
    - Engage customers early on in the process to determine needs and assess impact on distribution system; and,
    - Engage with Hydro One as early as possible in order to mitigate capacity constraints which may appear on both the distribution and transmission systems.

- **Customer timelines and requirements**: Customers' changing requirements, load demand, deadlines, and delays in providing information, signing offers to connect, and providing payments present a risk to project timelines. Customers frequently require more complicated connection schemes to ensure their current and future needs are met. In addition, an expedited construction schedule by the customer and/or a strain on Toronto Hydro resources risks the utility’s ability to complete the project on time and meet the customer’s timeline. Toronto Hydro strives to identify and mitigate these risks early on during the design and consultation phase through early engagement, key accounts interaction, customer intake processes, and pre-design teams. This overall process educates, and prepares both the customer and Toronto Hydro on servicing challenges, finding the best solution from a technical and economic standpoint, and identifying any servicing limitations which may occur prior to the issuance of an offer to connect. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service to ensure requests are continuously progressing. Customers are informed of expectations, timelines, and requirements early on through proper communications. Customers are also required to accept and make all OTC payments within 60 calendar days of receiving the OTC; and

- **Generation Connections:** Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work. The Generation Protection, Monitoring & Control Program at Exhibit 2B, Section E5.5 describes the steps Toronto Hydro is taking to mitigate these system constraints.

E5.2 Externally Initiated Plant Relocations and Expansion

E5.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 54.2	**2025-2029 Forecast ($M):** 76.0
Segment: Externally Initiated Plant Relocations & Expansion	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness - Reliability	

The Externally Initiated Plant Relocations and Expansion program (the "Program") captures work Toronto Hydro must undertake to relocate its infrastructure in response to third-party relocation requests to resolve conflicts between existing utility infrastructure and third-party capital construction projects. The Program also includes work that increases the capacity of Toronto Hydro's system where, in some instances, efficiencies can be achieved by integrating expansion work of the electrical system with the required relocation work. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems, transmission stations and rail crossings. The governmental third parties include the City of Toronto and the Ministry of Transportation of Ontario. Toronto Hydro also receives relocation requests from other agencies, such as Metrolinx, which it assesses in a fair and reasonable manner.

The City of Toronto is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. Toronto Hydro seeks to respond to relocation requests received from third parties in a safe, environmentally responsible, reliable, cost-efficient and timely manner. In pursuing this objective, the utility aims to meet its obligations under:

- The *Public Service Works on Highways Act, 1998* ("*PSWHA*");[1]
- The Distribution System Code ("DSC") section 3.1.10;

[1] RSO 1990, Ch P.49.

- The *Building Transit Faster Act, 2020 ("BTFA")*;[2]
- The *Building Broadband Faster Act, 2021* ("*BBFA*"),[3] including requirements under Ontario Regulation 410/22 made under the *Ontario Energy Board Act*, *1998* ("*OEB Act*");[4] and
- Agreements with third parties.

Typically, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach represents the minimum investment required to allow Toronto Hydro to continue providing safe and reliable electricity distribution service. However, at times, the nature of the project is such that like-for-like replacements are not the most efficient or desirable option. In these cases, there will be an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases, Toronto Hydro reviews the relocation request in conjunction with its future plans, and, if efficiencies can be achieved, works with the third party to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure driven by future load growth during an externally initiated relocation project, this is known as an "expansion" for the purposes of this Program.[5]

The timing, pace and spending under this Program is driven by third-party requirements outside of Toronto Hydro's control. The circumstances and discretion of third parties can cause schedules and project scopes to change. In order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro was approved to record variances in the difference between capital spending embedded in base distribution rates and the actual spending in the Externally Initiated Variance Account.[6] The Externally Initiated Variance Account was continued through to the end of the current rate period.[7] Toronto Hydro now seeks approval to record variances between capital spending embedded in rates and actual spend over the 2025-2029 rate period in the Demand Variance Account. Further details on the Demand Variance Account can be found in Exhibit 1B, Tab 2, Section 1 – Rate Framework and

[2] SO 2020, Ch 12.
[3] SO 2021, Ch 2 Sched 1
[4] SO 1998, Ch 15 Sched B.
[5] Also known as an "enhancement" under the Distribution System Code.
[6] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 50.
[7] EB-2018-0165, Toronto Hydro-Electric System Limited Decision and Order (December 19, 2019) at p. 198.

Exhibit 9, Tab 1, Section 1 – DVA Overview. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers from potential over recovery.

E5.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by responding to relocation requests and undertaking necessary, timely and cost-efficient system expansion work to accommodate future growth and increase system access, which should reduce the frequency and duration of construction disruptions for local area residents.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Complying with the *PSWHA*, which requires Toronto Hydro to work with prescribed entities to complete the relocation of Toronto Hydro infrastructure, when requested, and subject to the cost responsibility principles established therein; ○ Complying with the *BTFA*, where Metrolinx may require the utility to modify its infrastructure if necessary for a priority transit project; ○ Complying with the *BBFA* and associated regulations, where the Minister may require a distributor to perform work if it deems it necessary for the deployment of a designated broadband project; and, ○ Complying with section 3.1.10 of the DSC by responding to customer requests for the relocation of Toronto Hydro's assets.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by: ○ Obtaining, from third parties requesting distribution plant relocations, full or partial funding for newly installed/relocated assets pursuant to applicable cost sharing agreements; and ○ Combining externally initiated relocation work with expansion work where doing so provides a more prudent and cost-effective solution than conducting the expansion work at a later date.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing new infrastructure to current standards; and ○ Improving capacity, where required, through expansion work associated with the relocation.

E5.2.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Capacity Constraints

E5.2.3.1 Mandated Service Obligations

The *PSWHA* requires Toronto Hydro to work with public entities requesting relocation of hydro plant in a timely manner to promote the maintenance and improvement of public infrastructure.[8] In addition, Toronto Hydro has obligations under the *BTFA and BBFA* to deliver relocation services to expedite provincial transit and broadband infrastructure projects.

E5.2.3.2 Capacity Constraints

The scope, timing and pacing of these relocation projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. Toronto Hydro reviews load demand projections in the vicinity of externally initiated relocation work to identify opportunities to increase capacity

[8] These public entities must meet the definition of "road authorities" under the *PSWHA*: "road authority" means the Ministry of Transportation, a municipal corporation, board, commission, or other body having control of the construction, improvement, alteration, maintenance and repair of a highway and responsible therefore.

during a relocation project. When capacity needs are identified, Toronto Hydro integrates expansion work into the relocation project. This offers a more cost-effective solution than conducting the expansion work after the sponsor agency has completed its project.

E5.2.3.3 Customer Service Requests

Responding to relocation requests by customers is part of Toronto Hydro's customer service obligations as set out in section 3.1.10 of the DSC. Undertaking necessary, timely and cost-efficient system expansion work in connection with such relocations allows Toronto Hydro to accommodate future growth and increase system access while reducing the frequency and duration of construction disruptions for local residents.

E5.2.3.4 Program Need

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to capital work initiated by third parties. Any expansion work carried out under this Program is needed to meet anticipated future load growth to allow Toronto Hydro to coordinate projects with construction work being carried out by third parties.

The projects within this Program can be divided into four broad categories:

1. Requests from road authorities governed by the *PSWHA*;
2. Requests from agencies subject to *BTFA* for transit and *BBFA* for broad brand infrastructure;
3. Requests from other agencies and customers; and,
4. Expansion work undertaken in conjunction with the relocation work.

1. Requests from Road Authorities

The *PSWHA* outlines obligations for utilities with infrastructure on roads and those entities, such as the City of Toronto and Ministry of Transportation of Ontario, that have control of the construction, improvement, alteration, maintenance and repair of a highway ("Road Authorities"). For instance, typical relocation work arising from a City of Toronto initiated project includes relocating hydro poles to enable road realignment.

The *PSWHA* establishes a framework for determining cost responsibility between the parties for the relocation work. Under this framework, the Road Authority and the utility may agree upon the apportionment of the cost of the labour employed in the relocation, but, if there is no such agreement then the equipment and labour costs are divided equally between the Road Authority and the utility, and all other costs of the work (such as material costs) are the responsibility of the utility.

For relocation project components not covered under *PSWHA* but initiated by a Road Authority, such as streetscape improvement projects, or for non-like-for-like replacements (i.e. converting overhead to underground), Toronto Hydro aims to negotiate agreements that provide greater cost recovery than the default cost apportionment provided for under the *PSWHA*.

2. Requests from Agencies Subject to *BTFA* and *BBFA*

Since the previous 2020-2024 rate application two statutes have been passed which create additional obligations on utilities regarding the relocation of utility assets: the *BTFA* and the *BBFA.*

The *BTFA* was passed in 2020 to expedite the delivery of transit projects by removing barriers and streamlining processes that may result in delays. The *BTFA* outlines obligations for utilities regarding relocation of infrastructure related to priority transit projects. The *BTFA* also provides rules for cost allocation, whereby Metrolinx and the utility may agree on the apportionment of the actual cost of the work. However, if there is no agreement, Metrolinx must bear the actual cost of the work. Toronto Hydro successfully negotiated with Metrolinx that all *BTFA* relocations will be 100 percent funded by Metrolinx.

Currently, the *BTFA* designates four projects in Toronto Hydro's service area as priority transit projects:

1. The Ontario Line;
2. The Scarborough Subway Extension;
3. The Yonge North Subway Extension; and,
4. The Eglinton Crosstown West Extension, extending from Mount Dennis.

The *BBFA* was passed in 2021 to expedite the delivery of broadband projects of provincial significance.[9] This Act outlines obligations for distributors and transmitters to complete work

[9] Under the *BBFA*, the proponent and the distributor may agree on the apportionment of the actual cost of the work. If there is no agreement, there is a formula set out in Ontario Regulation 410/22 to determine the proponents share of the costs. For further details on the cost apportionment formula see s. 7 of Ontario Regulation 410/22 made under the *Ontario Energy Board Act,* and the OEB's Guidance on Cost Apportionment for Designated Broadband Projects dated February 9, 2023.

necessary for the deployment of a designated broadband project. There are no projects currently designated under the *BBFA* within Toronto Hydro's service territory.

3. Requests from Other Agencies and Customers

Where the *PSWHA, BTFA* and *BBFA* do not apply, the initiating third-party typically funds 100 percent of the relocation costs while Toronto Hydro funds any expansion work conducted in conjunction with the relocation work. Large scale projects such as the Toronto Transit Commission ("TTC") Yonge and Bloor Station Capacity Improvement Project and Easier Access Program, are examples of major projects not subject to the *PSWHA* provisions. In these cases, the third-party funds 100 percent of the relocation work.

Metrolinx is also currently working on transit projects that are not designated under the *BTFA.* The GO Expansion project will enable electric trains on several corridors. This requires adding new tracks, new stations and overhead catenary lines.[10] This includes expanding existing electrified transit through subways and Light Rail Transit ("LRT").

Work with Metrolinx is subject to a number of crossing agreements which govern cost sharing. Toronto Hydro is working with Metrolinx to negotiate cost responsibility for the additional relocation work. If, as a result of these negotiations, Toronto Hydro must bear some of the relocation costs, these costs will be recorded in the Demand Variance Account.

4. Expansion Work in Conjunction with Relocation Projects

Expansion work carried out under this Program is needed to meet anticipated future load growth. Pursuing expansion work in conjunction with the externally initiated relocation work allows required infrastructure to be installed where future construction may be restricted due to City streetscaping, commercial developments, City-imposed road work moratoriums or conflicts with other below grade utilities such as water, sewer, gas, and telecommunications.

Incorporating expansion work into the relocation work may result in significant cost savings compared to undertaking expansion work at a later date. Expansion work completed in conjunction with relocation projects may eliminate future third-party utility relocation and coordination work, avoid additional restoration work and minimize disturbance to the general public. Further,

[10] Metrolinx, GO Expansion, "online", https://www.metrolinx.com/en/projects-and-programs/go-expansion

undertaking expansion work in conjunction with relocation work ensures that Toronto Hydro infrastructure is installed in already congested rights of way without triggering the need for City approval of encroachment exemptions under the municipal consent requirements for infrastructure clearances. For instance, within the transit corridors of the Ontario Line and Eglinton Crosstown West Extension, Eglinton LRT and Finch West LRT, Toronto Hydro is taking the opportunity afforded by these relocations to expand its existing infrastructure in preparation for the expected load growth along the LRT lines. The expansion work is scheduled to occur between 2024 and 2030.

E5.2.4 Expenditure Plan

Toronto Hydro's projected spending in this Program is based on committed capital plans from third-parties including Road Authorities, Metrolinx and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications. These capital plans and project schedules are subject to change at the sole discretion of the sponsor agencies. Any such changes could impact the timing and execution of Toronto Hydro's relocation and expansion work. The projected quantum and timing of spending shown in Table 4, below, is based on the most current information available from third parties.

Table 4: Historical, Bridge and Projected Program Spending ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Project Cost	82.8	67.6	66.1	84.8	63.9	103.7	78.5	58.0	58.8	61.2
Capital Contributions	74.1	58.3	53.2	69.6	55.7	81.1	61.8	46.1	46.7	48.6
Net Cost	**8.7**	**9.3**	**12.9**	**15.2**	**8.2**	**22.6**	**16.7**	**12.0**	**12.1**	**12.6**

Given the uncertainty associated with the projects in this Program, Toronto Hydro sought rate funding for committed capital projects only (e.g. Eglinton Crosstown LRT and Finch West LRT) in its 2020-2024 rate application in the amount of $46.1 million. Any changes to these major projects or any new projects that emerged during the rate period would increase spending under this Program. Toronto Hydro requested and received a continuation of the Variance Account for Externally Driven capital to record the difference between the capital spending embedded in base distribution rates and the actual spending in the Program over the rate period.

Toronto Hydro's incurred capital expenditure costs in the 2020-2024 rate period were approximately $54.2 million, approximately $8 million over the planned amount. During the 2020-2024 rate period, there was an increase in the number and size of relocation projects. As well, there were increased costs to complete some of the work in the 2020-2024 rate period. For example, site conditions on the John Street project necessitated the use of more costly tunnelling and shaft construction than what was previously planned to accommodate the deeper elevation of new infrastructure design in order to clear other utility conflicts.

Toronto Hydro identified a number of major projects below in section E5.2.4.1 that are to commence or continue in the 2025-2029 rate period. Given the uncertainty associated with these projects, in order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro also requests approval to capture the difference between the capital spending embedded in base distribution rates and the actual spending over the 2025-2029 rate period in the Demand Variance Account. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers.

E5.2.4.1 Major Projects

Key projects with anticipated completion in the 2025-2029 rate period, including projects which have carried over from the 2020-2024 rate period, are described below.

1. Building Transit Faster Act

Metrolinx has issued notices to relocate all existing Toronto Hydro assets to accommodate construction activities and planned infrastructure for four priority transit projects designated under the *BTFA*: the (i) Ontario Line, (ii) Scarborough Subway Extension, (iii) Yonge North Subway Extension and (iv) Eglinton Crosstown West. Additional information on the four priority transit projects designated for execution are as follows:

i. Ontario Line Subway

The Ontario Line is an estimated $17 billion investment by the Province of Ontario to expand transit in Toronto with 15 stations. As shown in Figure 1 the 15.6 km Ontario Line will run between Exhibition/Ontario Place through downtown Toronto to the Ontario Science Centre.[11]

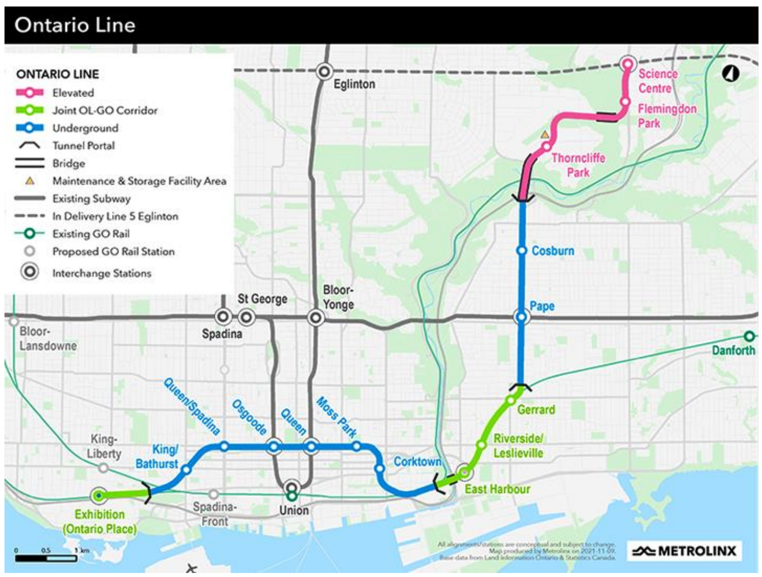


Figure 1: Proposed Map of Ontario Line

The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area. The City expects the Ontario Line corridor to experience significant growth in terms of population density and real estate developments.[12] Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. Completing expansion work in conjunction with the proposed construction allows Toronto Hydro to take advantage of construction efficiencies eliminating extensive future relocation work involving complex utility coordination, potential deviation on municipal consent requirements on infrastructure clearances, and disturbances to the public. Construction efficiencies may also be gained by using the same trench for multiple utilities and avoiding additional restoration

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[11]Metrolinx, Ontario Line – Projects, *"online"*. https://www.metrolinx.com/en/projects-and-programs/ontario-line.
[12] City of Toronto, 2021 Census: Population and Dwelling Counts, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf.

work. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has a current estimated completion date of 2031.

ii. Scarborough Subway Extension

The Metrolinx Scarborough Subway Extension (SSE) is an estimated $5.5 billion project and will bring the TTC's Line 2 subway service nearly eight kilometres further into Scarborough, from the existing Kennedy Station northeast to McCowan Road and Sheppard Avenue (see Figure 2). The extension is set to replace Line 3 with three new stations at Lawrence Avenue and McCowan Road, Scarborough Centre, and a terminal station at McCowan Road and Sheppard Avenue. Toronto Hydro has also planned to construct new underground assets within the construction zone to relieve existing area capacity constraints and meet future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has an estimated completion date of 2030.

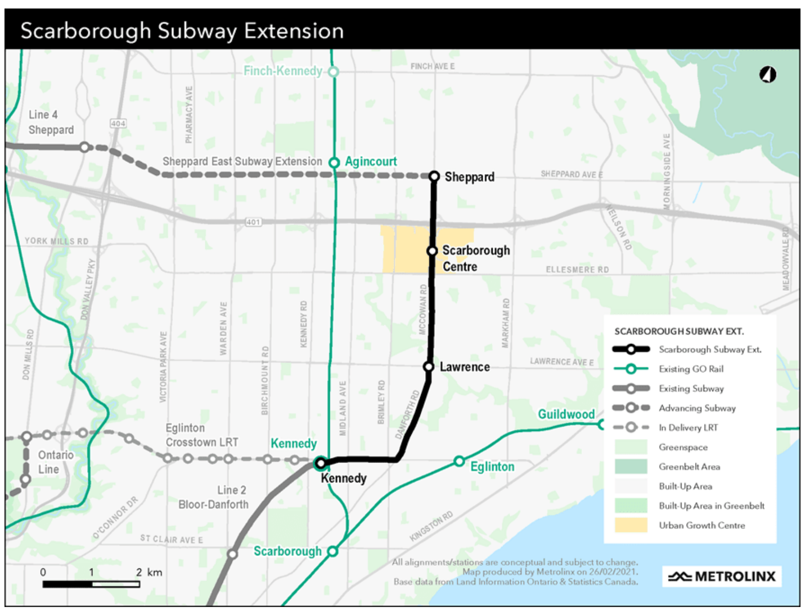

Figure 2: Proposed map of Scarborough Subway Extension

iii. Yonge North Subway Extension

The Yonge North Subway Extension is an estimated $5.6 billion project by the Province of Ontario. It will extend the TTC's Line 1 service north from Finch Station to Vaughan, Markham and

Richmond Hill. The 7.4km line will add approximately five stations. The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area up to Steeles Avenue, the limit of its service territory. The City expects the Yonge North Subway Extension corridor to experience significant growth in terms of population density and real estate developments. Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Construction started in February of 2023 and there is an estimated completion date of 2030.[13]

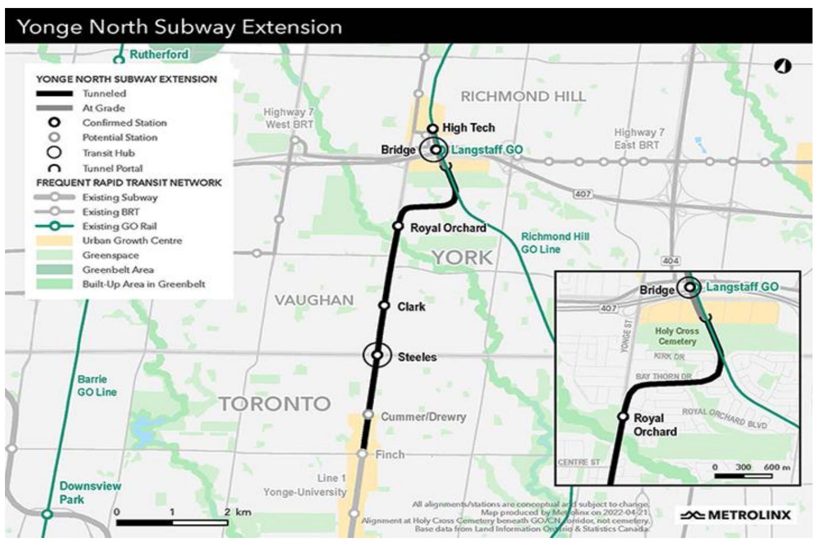

Figure 3: Proposed map of Yonge North Subway Extension

iv. Eglinton Crosstown West Extension

The Eglinton Crosstown West Extension ("ECWE") is an estimated $4.6 billion investment by the Province of Ontario that will bring rapid transit to Etobicoke and Mississauga. The western extension of the Eglinton Crosstown LRT will run approximately 9.2 km from Mount Dennis Station, west towards Renforth Drive and will operate mainly underground. Upon delivery of the ECWE, it

[13] Metrolinx, Yonge North Subway Extension, "online", https://www.metrolinx.com/en/projects-and-programs/yonge-north-subway-extension.

will create a continuous rapid transit system that spans from Scarborough, through midtown Toronto and into Mississauga.

With the new LRT, the Eglinton West LRT corridor will be more densely populated as the transit services will allow for increased growth and development. Toronto Hydro will be taking advantage of the relocation work to construct new infrastructure within the Eglinton West LRT corridor to alleviate capacity constraints and meet the anticipated load growth in the area. Expansion work will be completed in conjunction with the required relocation work causing less disruption to customers and enabling cost savings due to the elimination of road cut restoration costs. These savings are achieved through cost efficiencies in design and construction including savings in trenching costs, bulk concrete purchase savings, insurance, and digital mapping. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Tunneling commenced in April 2022, and the project is expected to reach completion in 2030.[14]

Figure 4: Proposed map of the Eglinton Crosstown West Extension

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[14]Metrolinx, Eglinton Crosstown West Extension, "online", https://www.metrolinx.com/en/projects-and-programs/eglinton-crosstown-west-extension

2. Metrolinx GO Expansion

The Go Expansion is a $13.5 billion investment by the Province of Ontario, to be carried out by Metrolinx, to enhance and update GO Transit infrastructure across the Greater Toronto and Hamilton Area to support more frequent, two-way, uninterrupted service via electric trains.

This initiative is a multi-year project on the GO rail network that will require extensive relocation of underground and overhead assets along the GO rail corridor in four project categories:

- **GO Electrification**: utilizing an overhead catenary system at 25 kV to operate electric motor trains and phase out diesel trains;
- **Grade Separation**: elevating the rail corridor to separate rail crossings from other modes of transportation;
- **GO Expansion**: expansion of rail tracks and associated infrastructure (i.e. tracks, rails and signals) to facilitate improved uninterrupted service; and
- **GO Station**: construction of new platforms, buildings, stations, traction power stations, parking and maintenance storage facilities to build a connected transit network.

As part of this project, Metrolinx requires the relocation of Toronto Hydro assets to meet infrastructure clearance requirements and to facilitate infrastructure, equipment and construction activities over the course of the proposed 10-year program. Figure 5 shows a typical GO Transit grade separation.

Figure 5: Grade Separation at Davenport Diamond

During the 2020-2024 rate period, Toronto Hydro has and will continue to execute Utility Preparatory Activities for the early and complementary works phase. In 2023, Toronto Hydro began investigating approximately 100 conflicts related to the development phase and scoped out approximately 35 relocation projects expected to be completed between 2023 and 2030.

Toronto Hydro is also developing a number of projects to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work. The expansion work involves the construction of new infrastructure within the construction zone of the GO rail corridor and stations. The timing of the proposed work is dependent on the priority and construction of the grade separation, track expansion, electrification and station work determined by Metrolinx.

3. TTC Easier Access Program

The TTC initiated the Easier Access Program with the goal of making all of its services and facilities, including key subway and Scarborough Rapid Transit stations, fully accessible to persons with disabilities. The *Accessibility for Ontarians with Disabilities Act*, *2005* ("*AODA*") requires that all public facilities and services are accessible by 2025.[15]

Significant subway station infrastructure is impacted by the need for *AODA* compliance, including the requirement that subway stations be constructed in a tiered configuration, similar to the one set out in Figure 6. In total, 13 stations were originally included in the program. Since the last rate application, the program has expanded to include a total of 16 stations. Many of the impacted stations are located in the downtown area necessitating relocation of Toronto Hydro's infrastructure. Toronto Hydro has already completed relocation work for five stations. Although these projects were initially scheduled to be completed entirely during the 2020-2024 rate period, there will be some carry over into the 2025-2029 rate period. Toronto Hydro is also evaluating opportunities for expansion.

[15] SO 2005, Ch 11.

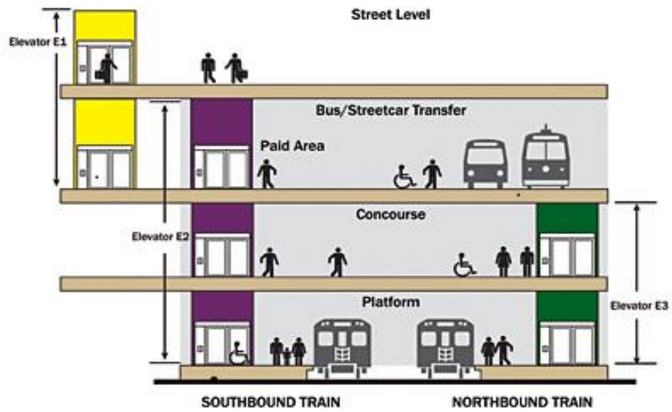


Figure 6: TTC Easier Access Station Concept

4. TTC Bloor-Yonge Station Capacity Improvements

The TTC is planning to modify and expand the existing Bloor-Yonge Station, the busiest station on the TTC. The project will increase and reconfigure existing below-grade subway platforms and add a new platform to address current congestion and accommodate future TTC ridership and neighbourhood density. This project will require the relocation of existing Toronto Hydro infrastructure. Early works are underway, and the project is expected to continue into the 2025-2029 rate period. Toronto Hydro will be reviewing the project for expansion opportunities.

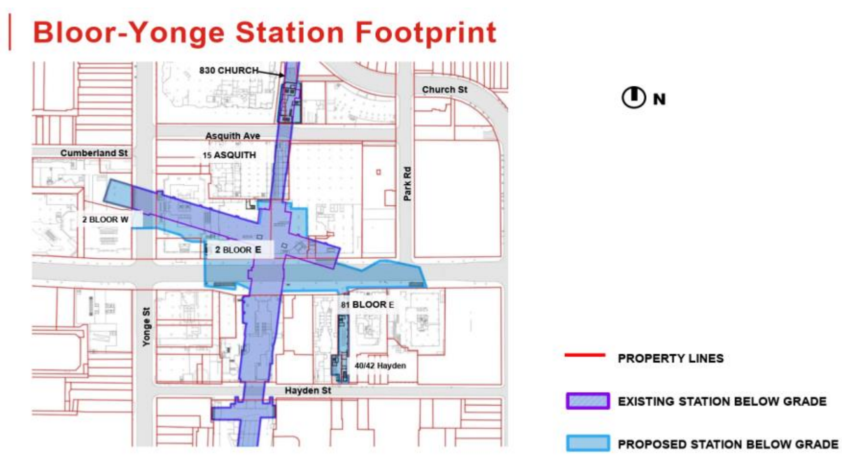


Figure 7: TTC Bloor-Yonge Station Capacity Improvements Concept-Footprint

5. City of Toronto Projects

The City of Toronto has approved a 10-year capital budget and plan of $49.26 billion for 2023-2032 which includes a variety of local and City-wide projects dedicated to the modernization, transformation and renewal of the City. [16] The City has approached Toronto Hydro to relocate the utility's infrastructure in conflict with a number of these projects. There are currently 42 active relocation projects, including those in connection with major development initiatives such as:

- **Basement Flood Protection Program ("BFPP"):** The City's BFPP is a multi-year program to reduce the risk of flooding by making improvements to the sewer system and overland drainage routes, increasing the resilience of the City to climate change including hazards such as flooding and heat.[17] The capital budget for the program is $2.1 Billion between 2023-2032.[18] The City of Toronto has requested that Toronto Hydro relocate its assets in order to accommodate sewer and watermain installations. The applications received to date are for relocations in Toronto's midtown. It is expected that there will be requests related to the program in other parts of the city.
- **City Bridge Rehabilitation Program:** The City of Toronto has over 900 bridges and culverts. The City's 2023-2031 Capital Plan has increased funding by $75.3 million over 2023-2031 to maintain the state of good repair of bridge and culvert infrastructure.[19] Repairs to city bridges typically include repairs to the concrete structure, removal and replacement of deteriorated expansion joints, cleaning and coating of steel girders, bearing replacement, and removal and replacement of barrier walls. Toronto Hydro has underground and overhead civil and electrical infrastructure situated within or upon the City's bridges and culverts that conflict with bridge rehabilitation work requiring relocation. In response to requests from the City, Toronto Hydro will temporarily or permanently relocate its infrastructure to accommodate City work.

[16] City of Toronto, 2023 Budget Launch Presentation https://www.toronto.ca/legdocs/mmis/2023/bu/bgrd/backgroundfile-230875.pdf
[17] City of Toronto, Basement Flooding Protection Program, https://www.toronto.ca/services-payments/water-environment/managing-rain-melted-snow/basement-flooding/basement-flooding-protection-program/
[18] City of Toronto, 2023 Program Summary Toronto Water https://www.toronto.ca/wp-content/uploads/2023/04/94eb-2023-Public-Book-TW-V1.pdf
[19] City of Toronto, 2023 Program Summary Transportation Services https://www.toronto.ca/wp-content/uploads/2023/04/94ec-2023-Public-Book-TS-V1.pdf

A number of projects are put forward every year by the City in connection with its capital plan. With continued City building initiatives and population growth projections, Toronto Hydro anticipates that third-party relocation activity will remain high during the 2025-2029 rate period as a result of City council budgetary approvals.

6. Waterfront Toronto

The Waterfront Secretariat leads the Toronto Waterfront Revitalization Initiative on behalf of the City of Toronto, as well as federal and provincial partners. There are number of projects run by Waterfront Toronto, including the Quayside development. Quayside is a 4.9-hectare (12-acre) area at the foot of Parliament Street, comprising about 3.2 hectares (8 acres) of developable land across five development blocks, as well as parkland, open space and future roads. Quayside will act as a hub, linking nearby neighbourhoods like St. Lawrence, the West Don Lands, the Distillery District, Bayside, and the future Villiers Island.[20]

As part of this development, Waterfront Toronto is proposing utility relocations, streetlighting, streetscape and development along Queens Quay between Bonny Castle and Parliament Street. The relocation work is expected to be completed in the 2025-2029 rate period. Toronto Hydro will be exploring expansion opportunities provided by this project.

E5.2.4.2 Upcoming Projects

Additional projects that are still in preliminary stages may emerge in the current or next rate period. Government and public agencies such as Metrolinx, TTC, and the City of Toronto have approached Toronto Hydro regarding their initiatives to expand and improve transit and to revitalize public space including, but not limited to, the following projects:

- **Metrolinx**: On Corridor Works project will transform the GO Transit rail network in the Greater Toronto and Hamilton Area over the next decade into a system that will deliver two-way all-day service every 15 minutes over core segments of the Go Rail network.
- **TTC/Waterfront Toronto**: Expansion of Union LRT and Queens Quay LRT stations to accommodate additional streetcar lines and passengers, including construction of a high order streetcar line in a dedicated transit right-of-way.

[20] Waterfront Toronto, Quayside https://www.waterfrontoronto.ca/our-projects/quayside

E5.2.5 Options Analysis

E5.2.5.1 Option 1: Completing Externally Driven Relocation Work Only

Toronto Hydro is obligated to relocate its electricity distribution equipment in response to road authorities defined under the *PSWHA* and for projects subject to *BTFA* and *BBFA*, as well as respond to relocation requests by third parties in a fair and reasonable manner. In general, when relocations are required, Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. This approach constitutes the minimum investment on the part of Toronto Hydro to continue providing safe and reliable electricity.

E5.2.5.2 Option 2 (Selected Option): Completing Externally Driven Relocation Work and Expansion Work

Sometimes the nature of a project is such that it is not the most efficient or beneficial option to undertake only relocation work. Upon receipt of a relocation request, Toronto Hydro reviews the future capacity needs in the area and evaluates whether there are opportunities for construction efficiencies available to support undertaking expansion work along with the relocation work. An example of how expansion and relocation work may be combined to maximize efficiencies is the Port Lands Flood Protection Initiative (PLFP).

Upon being advised of the project by the Waterfront Toronto, and the need to relocate its infrastructure, Toronto Hydro reviewed its capital plan to identify expansion work opportunities that could be executed along with the relocation work. Toronto Hydro performed a system analysis to determine expected load growth on the feeders in the area. In reviewing the current feeder loading conditions and approved loads through customer connections and factoring in contingency scenario loading, Toronto Hydro determined that by 2027, local feeders would be heavily loaded, requiring relief. To accommodate this anticipated growth, expansion work was integrated into the work plan to be executed during plant relocation initiatives.

Executing expansion work in coordination with the Waterfront Toronto's capital work was determined to be preferable to just undertaking the relocation work for the following reasons:

- It often is less expensive to construct new civil infrastructure to support the expected load growth in the area if such work is undertaken in conjunction with the relocation work required by the Waterfront Toronto's project. If the expansion work is undertaken in the future there would be a need for increased coordination initiatives with third-party utilities, more potential for deviation from municipal consent requirements on infrastructure clearances and additional civil construction and restoration work in the area.

- The City's road cut moratorium could prevent Toronto Hydro from installing additional infrastructure when needed to address the expected load growth. The City of Toronto imposes a five-year moratorium on road cuts in an area after road resurfacing is completed. Breaking the moratorium requires City approval and payment of a fee. Failing to complete expansion work during the relocation phase of a project could lead to Toronto Hydro having to install costlier and less optimally located facilities to meet the anticipated demand.
- Completing the expansion work and the relocation work together avoids prolonged disturbances to the residents and businesses in the neighbourhood.

E5.2.6 Distribution Grid Operations Consultation

Consultation with Toronto Hydro's Distribution Grid Operations ("DGO") Department, which coordinates all work on the distribution system, early in the design process improves outcomes for third parties and customers more broadly. Early consultation allows the DGO to sequence work on feeders to accommodate third-party relocation work more quickly while minimizing disruptions to customers in the area. The DGO also provides an operational perspective during design review. DGO is able to identify design modifications to improve system reliability early on, thereby avoiding any delay to the overall project.

E5.2.7 Execution Risks & Mitigation

Toronto Hydro's projected spending in this Program is based on a combination of deferred projects from the last rate period, future committed projects and anticipated projects. There is risk that projects in these categories or their timing may be modified or may not materialize as anticipated. In addition, new projects can emerge, adding to program costs. To mitigate the effects of these risks for ratepayers, Toronto Hydro requests approval to record variances in the Demand Variance Account.

The projects proposed under this Program are largely dictated by the schedule and plans of third parties. Third parties often face their own constraints with respect to the execution and completion timelines for their projects. To accommodate work on projects, and ensure that projects are completed within the timelines requested by customers, Toronto Hydro may undertake work during off-peak hours on evenings and weekends, as necessary. Toronto Hydro constantly monitors changes to codes, bylaws and Legislation which impacts its relocation operations to ensure that its processes and standards align with requirements.

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 120.9	**2024-2029 Cost ($M):** 236.3
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety	

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to efficiently connect customers to Toronto Hydro's distribution system. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios, as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months).[1] This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2020-2024 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers to relieve station bus overloads;
- Feeder cable upgrades and load transfers to improve capacity and asset utilization;
- Equipment upgrades to increase available capacity and reduce the number of switching restrictions experienced during the summer peak; and
- Civil enhancements to remove system bottlenecks and support additional electrical capacity.

[1] " First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage.
[2] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019), Exhibit 2B, Section E5.3.

1 ## E5.3.2 Outcomes and Measures

2 **Table 2: Outcomes & Measures Summary**

Customer Focus	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades in areas of high load growth in the downtown and Horseshoe area. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: o Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers; o Improving restoration capabilities in the downtown or Horseshoe systems by offloading highly loaded feeders; o Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and o Improving downtown reliability by maintaining or reducing the number of heat restricted feeders.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

As per sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"), Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis. The utility must also connect new customers within the timelines prescribed by the OEB's service quality standards without adversely affecting the quality of distribution services for existing customers.[3] The OEB requires 90 percent of connections to be completed on time. Toronto Hydro achieved 99.9 percent of new residential and small business services completed within the prescribed timelines, and 99.1 percent of new high voltage connections completed within the prescribed timelines. The investments in this Program are specifically targeted to meet the OEB's service quality standards.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded feeders in the downtown are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe, highly loaded feeders are defined as those with peaks of 400A, which is the standard planning practice as it leaves at least one third of a feeder's capacity available to support tie feeders under contingency.

The rapid influx of dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects that rapid growth will cause multiple buses to reach their rated capacity. The forecasted growth in the distribution system is based on the Toronto Hydro's Station Load Forecast. The actual demand will vary based on the actual realization of load on the system. This can depend on multiple factors and emerging trends such as electric vehicle

[3] Section 7.2 of the *Distribution System Code* requires Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days. Ontario Energy Board, *Distribution System Code* (August 2, 2023).

("EV") uptake and pacing of heating electrification. Section E5.3.5 Options Analysis explores how future energy scenarios can impact the requirements of this Program.

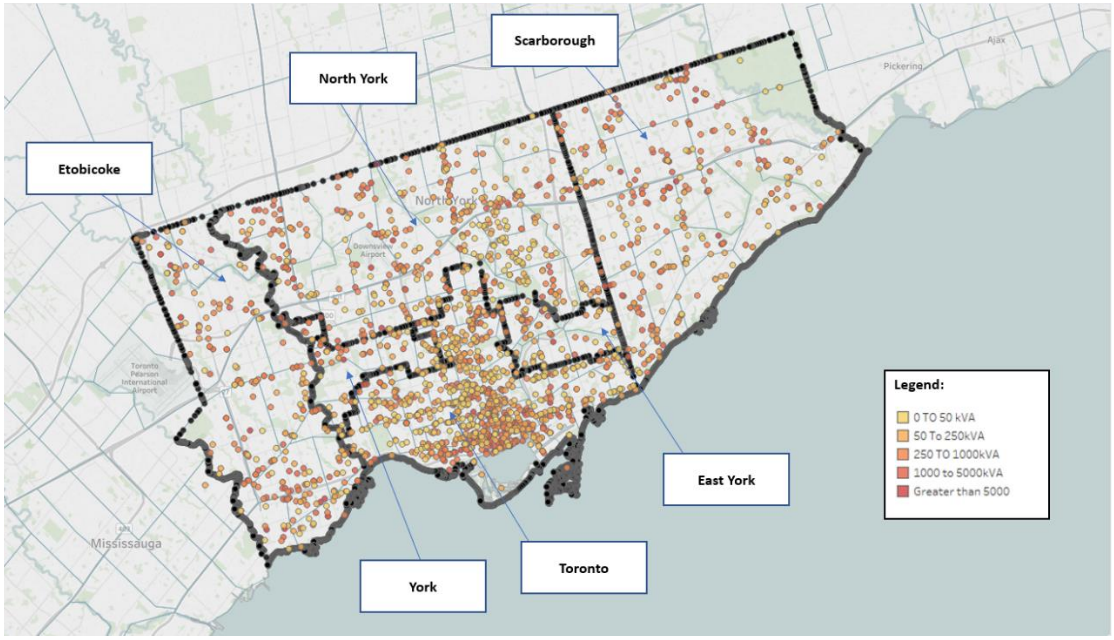
As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the Downtown and Central Waterfront Area in Table 4), which service a large amount of load or are experiencing high growth, are serviced by feeders that are already highly loaded and at risk of overloading in the upcoming years. Growth in these areas has been driven in large part by multiple storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate constraints, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders reduces the level of reliability, thereby causing Toronto Hydro to fail in meeting a top priority of these customers as identified through customer engagement.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer Operations program.[4] In most cases, system planner input is required to determine how to service the customer in the most efficient manner. In constrained areas of the system, the utility's ability to respond to customer service requests within the OEB-prescribed timelines, without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program.[5] Toronto Hydro utilizes the City of Toronto's land planning information to help assess which areas of the system are in most urgent need of additional capacity to accommodate customer service requests in a timely and cost-effective manner.[6]

Figure 1 shows the load additions (connection applications involving new or increased load) submitted to Toronto Hydro from 2018 to 2022 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4, Tab 2, Schedule 8.
[5] *Supra* note 3.
[6] City of Toronto, *Development Pipeline 2022 Q2* (February 2023), « online », https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf



1 **Figure 1: Load Additions in the City of Toronto during the 2018-2022 Period**

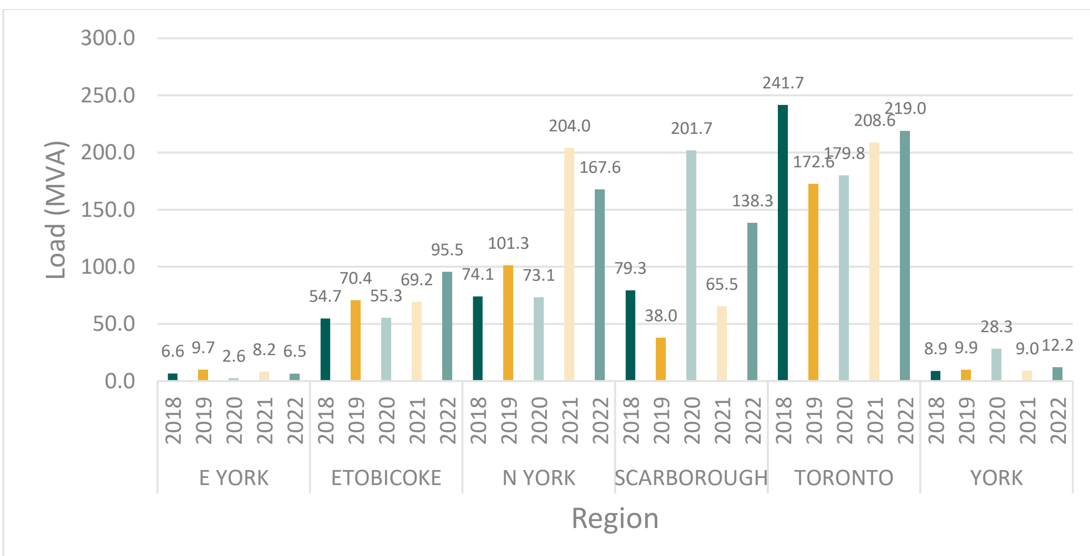


Figure 2: Load Additions by Region during the 2018-2022 Period

2 The City of Toronto is experiencing an increase in development which is expected to continue
3 throughout the 2025-2029 rate period. Table 4 below provides a summary of the projects submitted
4 to the City of Toronto's Planning Division between 2017 and 2022 Q2, and Figure 3 is a map of the
5 residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2017-2022 Q2)[7]

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

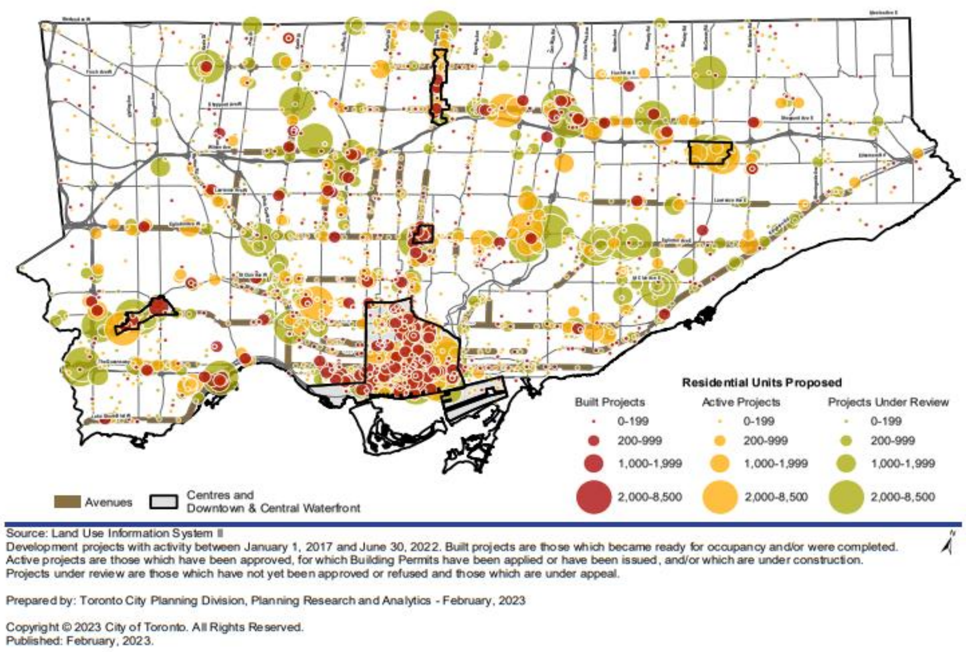


Figure 3: Residential units proposed (2017-2022 Q2)

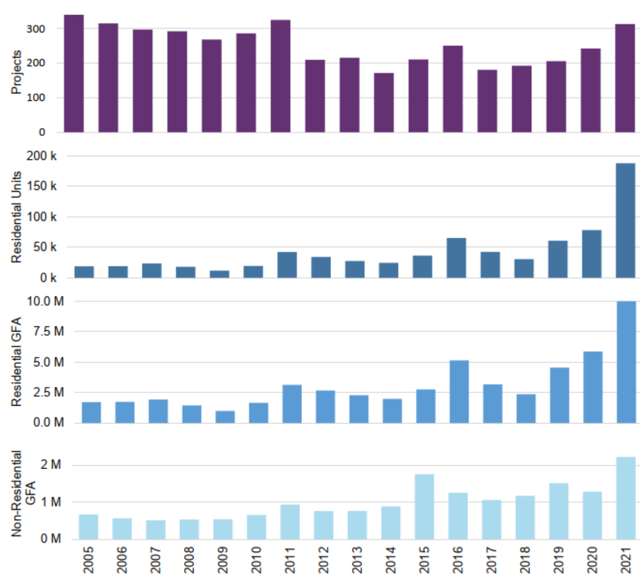
As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the Downtown and Central Waterfront area, where 43,513 residential units have been built as of the end of 2022 Q2 and 180,652 units are in the pipeline for future development. Another area

[7] *Supra* note 6.

experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 38,361 units in the pipeline.

In the Horseshoe area, Sheppard East Subway Corridor, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which is expected to continue: (i) in the Sheppard East Subway Corridor area, 22,699 units are in the development pipeline; (ii) in the Etobicoke Centre area, 17,575 are in the development pipeline; (iii) in the North York Centre area, 12,330 are in the pipeline; and (iv) in the Scarborough Centre area, 29,260 are in the pipeline.[8]

The number of projects submitted to the City of Toronto have remained relatively consistent over the years, ensuring a steady influx of projects and a healthy pipeline of projects. However, the number of residential units proposed and overall Gross Floor Area ("GFA") of the projects have increased substantially over the years, indicating each project has become larger and more complex overall. Figure 4 shows the trend of applications over the years. For Toronto Hydro, these large projects create single points of concentrated load that require detailed analysis and consideration when planning for their connections and managing system load overall.



Source: City of Toronto, City Planning: Land Use Information System II

Development projects submitted each year from 2005 to 2021, and the total number of residential units, residential GFA, and non-residential GFA proposed. Residential and non-residential GFA is in square metres.

Figure 4: Trend of Projects, Residential Units and GFA by Application Intake Year, 2005 to 2021

[8] *Supra* note 7.

Therefore, Toronto Hydro expects a steady stream of customer service requests for new connections over the 2025-2029 rate period and beyond. To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, Toronto Hydro must focus its efforts in the downtown and Horseshoe areas where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets above their rated capacity for prolonged durations increases the risk of failure and corresponding loss of supply to customers. These conditions can lead to the premature failure of primary overhead conductors and undersized legacy assets (e.g. underground paper insulated lead-covered "PILC" cables), that were installed over 35 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2012, Toronto Hydro's distribution system has experienced 293 cable and splice failures on legacy PILC cable. Where cables are at the largest standard size, instead of cable upgrades to alleviate overloads on the feeders, load transfers to other feeders with capacity will be considered.

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor's tensile strength.[9] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[10,11] Similarly, underground cables, such as the cross-linked polyethylene ("XLPE") cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under

[9] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.

[10] F. Jakl and A. Jakl. "Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions." *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.

[11] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.

mechanical stress (e.g. bends in the route), leading to deformation of the cable. This in turn can lead to electrical failures resulting in outages.[12]

E5.3.3.4 Addressing Drivers and Need

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

- **Bus Level Load Transfers**: load transfers between station buses to alleviate overloaded buses. [13]
- **Feeder Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or upgrading undersized feeder trunks to the current standard.[14]
- **Equipment Upgrades**: carried out in areas like network vaults to increase unit size and associated capacity, which may reduce the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrade by allowing for more feeders to be installed.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[15]

Table lists the specific station buses planned for bus level load relief during the 2025-2029 rate period, and Figure shows the stations' locations. The station bus can be relieved by expanding the capacity of the bus through bus expansion, or by relieving the load of the bus through bus transfers. Bus transfers can be performed by transferring load between buses within the same station or to another station in the area. Additionally, bus balancing can be achieved during transfers to ensure that the bus capacity within transformer stations is optimized.

[12] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.
[13] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[14] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[15] Exhibit 2B, Section E7.4.

The completion of Copeland TS Phase 2 under the Stations Expansion program will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS. [16,17] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately upon its energization. Relief for Horner TS and Manby TS will follow in the 2025-2029 rate period after the expansion of Horner TS is completed during the 2020-2024 rate period.

Table 5: Station Buses Planned for Relief within 2025-2029

Station	Bus	Estimated Load to Transfer (MVA)	Area
Basin	*A7-8*	15 – 25	Downtown
Bathurst	*J&Q*	5 – 20	Horseshoe
Bermondsey	*B&Y*	10 - 25	Horseshoe
Bridgman	*A1-2B*	5 -15	Downtown
Copeland	*A1-2CX*	5 – 15	Downtown
Dufferin	*Note 1*	5 – 15	Downtown
Esplanade	*Note 2*	10 - 20	Downtown
Fairbank	*B & Q*	15 – 30	Horseshoe
Finch	*B&Y, J&Q*	25 - 55	Horseshoe
Horner	*B&Y*	25 - 40	Horseshoe
Leslie	*B&Y*	25 – 40	Horseshoe
Manby	*B&Y, Q&Z*	20 - 50	Horseshoe
Rexdale	*B&Y*	5 - 20	Horseshoe
Runnymede	*J&Q*	15 – 30	Horseshoe
Sheppard	*E&Z*	5 – 20	Horseshoe
Terauley	*Note 2*	10 - 20	Downtown
Windsor	*Note 2*	10 - 20	Downtown

Note 1: Targeting bus supplying feeders in area bounded by St. Clair Ave, Queen Street W, Bathurst Street, and Keele St.

Note 2: Stations that are scheduled for Relief as part of Copeland Phase II expansion.

[16] *Ibid.* Copeland TS Phase 2 is expected to be completed by 2023/2024.
[17] Not all stations listed are addressed through the Load Demand program.

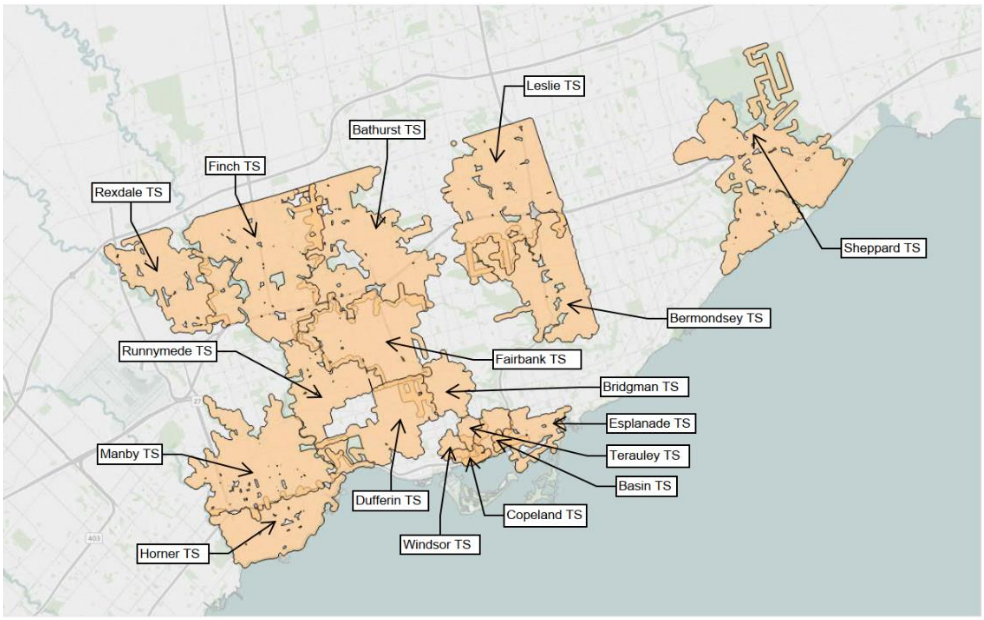


Figure 5: Stations Targeted for Relief during the 2025-2029 Rate Period

If the buses outlined in Table above are not relieved, it may not be possible to connect new customers to these station areas. As a result, Toronto Hydro may need to supply new service requests in the areas serviced by these stations from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work. For example, capital contributions from connecting customers are required when revenue from their demand does not cover the cost of expansion work, as determined by the Economic Evaluation Model.[18] This may occur when significant expansion work is required for smaller loads.

Station bus load forecasts are re-evaluated annually.[19] Based on updated results, it may be necessary and prudent for Toronto Hydro to reprioritize load transfers. Some of the buses that Toronto Hydro plans to address in the 2025-2029 rate period originally appeared in plans for relief during the 2020-2024 rate period. For the reasons summarized in Table 6 below, these investments were reprioritized, with portions of the projects completed in the 2020-2024 rate period, and remaining portions to be addressed during the 2025-2029 rate period.

[18] Exhibit 2B, Section E5.1.3.1.
[19] Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

When reviewing work to be targeted within the Program, Toronto Hydro will also consider work that can potentially be deferred using Non-Wire Solutions (NWS).[20] In the case of Manby TS and Horner TS in Table 6, the short-to-medium term capacity constraints of the buses due for load transfers were mitigated by identifying opportunities where local demand response ("DR") could be leveraged to reduce peak loads. The NWS program enables efficient and cost-effective load management, and can be leveraged in the 2025-2029 rate period in the prioritization of load transfers.

Table 6: Load Transfers projects continuing from 2020-2024 to 2025-2029

Station	Bus	Reasoning
Horner	*B&Y*	Based on regular re-evaluation of the proposed work in this Program, load transfers between Fairbank TS and Runnymede TS were prioritized ahead of these stations for the 2020-2024 period. The Horner TS and Manby TS load transfers were re-prioritized, and only the portions of the load transfers that required immediate attention were addressed in the 2020-2024 rate period. The remaining transfers are scheduled to be completed in the 2025-2029 rate period.
Manby	*Q&Z, V&F*	

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installations. Extensive cable pulling and splices are then required to complete the transfer of customer loads from the existing feeders to the new feeders.[21] Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. In the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches. Therefore, the scope of work required when performing Load Transfer projects vary depending on how much upgrades are required on existing civil and electrical infrastructure as mentioned above.

[20] Exhibit 2B, Sections E7.2

[21] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last for hours due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers the system can be served by the standby supply may be limited. Those customers that cannot be served by the standby supply would experience lengthy service interruptions, which would adversely impact reliability. Having available capacity on additional tie feeders allows for quicker restoration during more catastrophic events where cascading load transfers are required, because more operational options will be available to restore customers.

When the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed.

In addition to the expected reliability improvement, having the flexibility (in the form of switching equipment) to de-energize feeders improves Toronto Hydro's ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders.

When processing new customer connection requests, Toronto Hydro conducts an analysis to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, Toronto Hydro may decide to perform feeder level load transfers if the assets are already at the maximum standard cable size, or if the bus that supplies the feeder has available capacity but feeder loading is not balanced.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers.

The sections that follow describe the Feeder Level Load Transfers and Upgrades planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

a. The Horseshoe System

To manage load growth in the Horseshoe area, Toronto Hydro plans to undertake capital investments in feeder level load transfers and feeder upgrades in the Scarborough, Etobicoke, and North York areas. Load transfers are preferred over feeder upgrades because the overhead system, which serves the majority of the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders. Cable upgrades are also performed in the Horseshoe when segments along the cable are undersized and limit the overall carrying current capability along the feeder. Such undersized segments along feeders are typically legacy aluminum cables which are upgraded to standardized copper cables to raise the maximum current carrying capacity to 600 A, which is an increase of up to 100 A in capacity, or about the equivalent of 2300 customers.[22] There are 119 Horseshoe feeders forecasted to be highly loaded by 2029 and Toronto Hydro plans to relieve 23 of the highest priority feeders (i.e. those with the highest level of overloading) through feeder transfers or cable upgrades in order to manage the forecasted growth over the 2025-2029 rate period. Toronto Hydro will continuously assess actual feeder conditions before investing in any upgrades or transfers.

b. The Downtown System

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2025-2029 rate period. If there is a loss of supply in these areas, overloaded standby supply means that there are less options available to restore customers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2025-2029 rate period based on the Toronto Hydro's Station Load Forecast. By the

[22] Exhibit 2B, Section E7.1.

end of 2029, there is projected to be 154 highly loaded feeders in the downtown system (representing approximately 20 percent of downtown feeders) if no work is done to address them.

As a result, in the 2025-2029 rate period, Toronto Hydro plans to relieve 49 of the highest priority feeders in the downtown area to manage load growth and continuously meet system reliability goals through feeder upgrades and feeder load transfers. By comparison, in the 2020-2024 rate period, Toronto Hydro relieved 18 highly loaded feeders through cable upgrades and transfers. This increase in the number of highly loaded feeders planned for relief is due to the rapid growth of the number of highly loaded feeders. Toronto Hydro will continue to prioritize the feeder transfer and upgrade projects based on the latest information on how load is materializing on the system and regular re-forecasting efforts.

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to maximize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A62A supplies 16 customers in and around the downtown core along Dundas St. E. to Jarvis St., and along Yonge St. from Dundas St. to Richmond St. Many of these customers are key account customers operating commercial complexes, outdoor public and event spaces, university campus services and government locations. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older civil standards (therefore unable to accommodate the latest cable standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. In addition to capacity constraints, the clay duct tile is typically collapsed, and in need of rebuild. Such legacy square ducts span over 4.6 kilometres and contain feeders supplying in the downtown area including hospitals, as well as other large customers.

Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned feeder upgrade will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and duct bank rebuilds.

Figure 6: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area requires greater capacity than is available with existing feeders. These new feeders are then utilized to relieve the existing load and service any upcoming demand in the area. In cases where bus expansion is not possible at the station, the feasibility of expanding the bus with new feeder positions at nearby stations are explored. The new feeders from nearby stations will supply the load from the station that has reached or exceeded its capacity. One instance where new feeders from a station are required to offload a nearby station is Richview TS offloading existing feeders from Finch TS. The area which Finch TS services, spanning from Hwy 27 to Jane St, and Steeles to South of Hwy 401, have feeders that are highly loaded and require support and relief to accommodate upcoming load growth in the area. With Finch TS already highly loaded at the bus as well, new feeders from Richview TS, which is a nearby station south west of Finch TS, will support by offloading the highly loaded feeders from Finch TS.

3. Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods. If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro’s ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to maintain or reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The equipment upgrades as part of this Program aim to upgrade undersized network units that are at-risk of overloading and may create summer switching restrictions. An example of a network unit is shown in Figure . A network unit consists of a primary switch, network transformer, and network protector.

Figure 7: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various primary feeders, and are interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement.

Current key customers on the network system include hospitals, hotels, telecommunication and government buildings.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2020-2024 rate application, Toronto Hydro indicated its goal of reducing the number of summer switching restriction feeders to under 10, and has been doing so accordingly as seen in its progress presented in Table below.

Table 7: Summer Restrictions by Year

Summer Restrictions	**Year**					
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Number of Feeders Restricted	21	9	6	4	4	5

To address the growth in demand of the number of network units under contingency, Toronto Hydro plans to upgrade 5 network units during the 2025-2029 rate period.[23] Toronto Hydro's goal is to continue maintaining the total number of restrictions to below 10 by during the 2025 to 2029 rate period. To achieve this goal, Toronto Hydro will also mitigate any potential primary feeder restrictions via cable upgrades and load transfers.

[23] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.

Where other equipment upgrades are required due to capacity needs based on forecasted growth on the feeders and not due to asset end of life, this Program will also upgrade capacity in order to manage growth and mitigate overloading assets.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. Table summarizes the expected station upgrades within the 2025-2029 rate period that may require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure .

Table 8: Stations Requiring Civil Egress Rebuilds

Station	Switchgear Unit	Associated Work	Target Completion Year
Bridgman TS	*A1-2H, A7-8H*	*Switchgear Renewal*[24]	2026, 2029
Danforth MS	*A1-2DA*	*Switchgear Renewal*[25]	2028
Downsview TS	*New TS*[26]	*New TS*[27]	2029+
Duplex TS	*A1-2DX*	*Switchgear Renewal*[28]	2026
Manby TS	*B-Y, V-F, T3/T4, T13/T14*	*Switchgear Renewal and Transformer Renewal*	2027, 2029
Wiltshire TS	*A5-6WA*	*Switchgear Renewal*[29]	2029
Windsor	*A5-6WR, A3-4WR*	*Switchgear Renewal*[30]	2027, 2029

[24] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[25] *Supra* note 24.
[26] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[27] *Ibid.*
[28] *Supra* note 24.
[29] *Ibid.*
[30] *Ibid*.

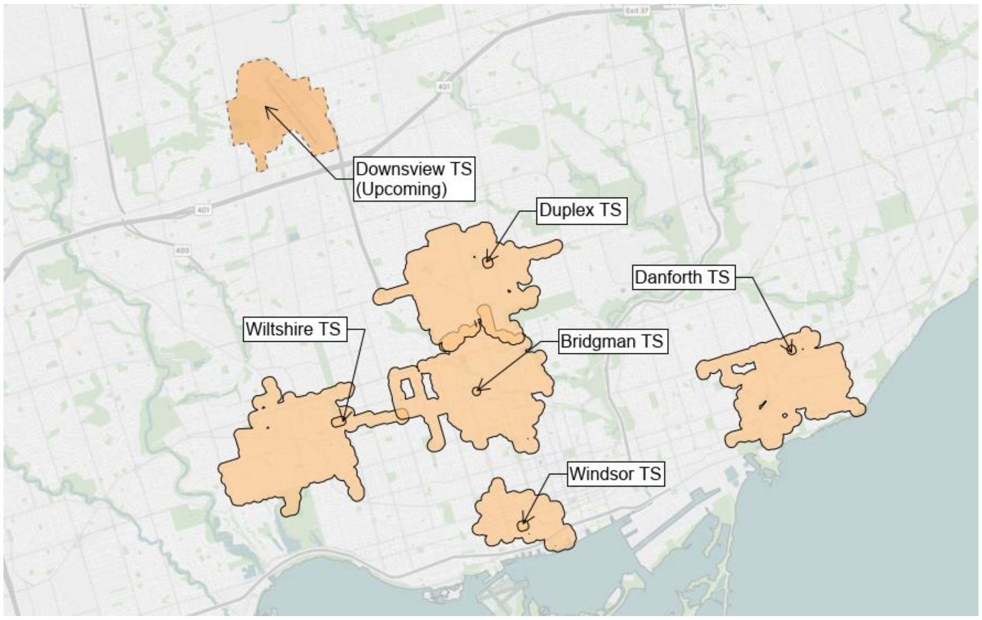


Figure 8: Stations Targeted for Civil Enhancements during the 2025-2029 Rate Period

Civil work can vary depending on the location of the asset expansion or renewal within the station, as well as the existing civil infrastructure in and around the station. For example, the Carlaw TS switchgear renewal scheduled for 2023 and 2024 will have new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates additional civil work around the station with added cable chambers and ducts being required. Another example during the 2020-2024 rate period is planned relief of Basin TS to the south to Carlaw TS due to the rapid growth around Basin TS including Ashbridge's Bay, GO Transit and the Port Lands developments. Additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans.

In addition to supporting station renewal or expansion, civil infrastructure throughout the distribution system is required to be expanded or upgraded in areas that limit growth and electrical capacity. An example of infrastructure upgrade and expansion during the 2020-2024 rate period is along John Street between Front Street and Stephanie Street. The rebuilding of John Street addressed existing failing infrastructure and installed additional infrastructure required for growth. The scope consisted of rebuilding cable chambers, cable chamber roofs, vault roofs, vault rebuilds, collapsed ducts, and the expansion of ducts required for communication cables and contingency tie cables between stations. This rebuild ensured that existing key account customers fed from Windsor

TS would not be impacted by civil failure, enabled the connection of new customers in a timely manner, ensured that duct system can accommodate the fiber communication system, and enabled the ability to tie Cecil TS to Windsor TS to further mitigate against station contingency events. This was of great importance to the city because John Street connects many of Toronto's key cultural institutions to the waterfront. In the 2025-2029 rate period, Toronto Hydro is planning to invest in similar civil upgrades along Victoria Street, between Dundas Street and Lombard Street to rebuild legacy duct banks (i.e., square clay tile ducts) and undersized cable chambers that contain feeders supplying key account customers such as hospitals.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the ability of crews to perform work safely.

E5.3.4 Expenditure Plan

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Demand	24.0	29.7	30.8	22.6	13.8	50.0	56.7	42.3	38.8	48.6

Table 5: Cost Breakdown by Type of Work ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Transfer (Bus)	8.7	13.6	15.3	16.5	4.9	34.9	30.1	20.9	16.3	7.7
Load Transfer (Feeder)	0.82	0.87	1.3	0.85	2.9	2.5	7.7	11.5	5.4	8.2
Cable Upgrades	7.3	5.9	8.3	4.7	2.4	7.6	7.1	10.0	10.0	5.0
Equipment Upgrades	0.32	0.10	0.42	0.23	0.0	0.0	0.38	0.81	0.40	0.41
Civil Enhancements	6.9	9.3	5.5	0.05	3.6	5.0	11.5	0.0	6.7	27.3

The 2025-2029 expenditure plan is based on the specific work that is planned in each year. As is true with the 2020-2024 rate period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2020-2022, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 131 MVA on highly loaded buses through bus level load transfers or bus expansion;
- Reduction in the amount of highly loaded feeders by 10 through feeder level transfers and feeder upgrades;
- Improvement to the civil infrastructure associated with station expansion of Carlaw TS, Horner TS, Runnymede TS, Strachan TS, Terauley TS, as well as the upgrade to John street civil infrastructure between Front Street and Stephanie Street; and
- Maintaining the number of summer switching feeder restrictions to under 10.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth.[31] Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand. For example, Toronto Hydro planned to address 28 highly loaded feeders through cable upgrades and load transfers. However, with the changing load growth needs of the system and reprioritization, 18 highly loaded feeders have now been planned to be addressed. Instead, additional investments were allocated to bus level load transfers with the following stations undergoing transfers that were not originally planned for: Runnymede, Carlaw, Leaside, George & Duke, Dufferin, and Terauley stations. This resulted in approximately an additional 100 MVA of bus level load transfers.

Investments in the 2025-2029 rate period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on Toronto Hydro's Station Load Forecast. As described in section E5.3.3, this Program is made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project, which will allow

[31] Exhibit 2B, Sections D2.3, 3.2.1, and C3.3.

Toronto Hydro to provide relief to the buses at Strachan TS, Windsor TS, Terauley TS and Esplanade TS.[32]

The costs for bus level load transfers were forecasted using a cost per MVA transferred value, based on evaluations of historic project actuals. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions.

Load transfers in the Horseshoe area, which is generally served by the overhead system, can vary in cost depending whether the transfer requires tie switches between feeders, or whether expansion work as well is required. The cost would be considerably lower in areas where only a switch is required for a transfer compared to when expansion work would be required. Additional expansion work can include civil and electrical work in order to transfer load which can significantly increase the cost of the project.

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 49 feeders in the downtown area and 23 feeders in the Horseshoe area for relief through feeder upgrades and feeder load transfers during the 2025-2029 rate period.

Any cable upgrade to the trunk of a feeder is estimated to upgrade approximately 1,000 meters of cable in the downtown and 2,000 meters of cable in the Horseshoe, which will include civil upgrades for half of the distance. Civil upgrades include duct banks, cable chambers, and splices along the feeder route. The unit cost assumes 1,000 meters of upgrades per targeted downtown feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters. In the Horseshoe, the average length of undersized aluminum cable egress that is targeted for upgrades to standardized copper cable is approximately 2,000 meters.

[32] Exhibit 2B, Section E7.4.

E5.3.4.3 Equipment Upgrades

Toronto Hydro plans to complete five network equipment upgrades during the 2025-2029 rate period in order to maintain its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2020-2024 rate period.

E5.3.4.4 Civil Enhancements

Toronto Hydro plans to increase capacity and add new feeder cell positions at the following stations in the 2025-2029 rate period: Bridgman TS (downtown), Danforth TS (downtown), Downsview TS (Horseshoe), Duplex TS (downtown), Manby (Horseshoe) Wiltshire TS (downtown), and Windsor TS (downtown). Often, when station capacity is expanded and new cell positions are installed, additional feeders need new or expanded routes outside of the station via new or upgraded egress cable chambers and duct banks.

Toronto Hydro also plans to enhance its civil infrastructure in capacity constrained areas within the City of Toronto. The civil enhancement plan will address cable chambers and ducts in need of rebuild, and legacy infrastructure including square ducts which span over 4.6 kilometers, which limit the size of feeders to smaller diameter cables causing bottlenecks in capacity.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Load growth:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. Forecasting of highly loaded areas is used to determine which projects should be prioritized.
- **Contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or if they should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 6 above, two buses that were expected to be overloaded in the 2020-2024 rate period are being deferred to the 2025-2029 rate period. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 6 were no longer immediately required.

Additionally, Toronto Hydro enables cost savings through NWS. Peak shaving through Local DR can reduce immediate needs for bus level load transfers in this Program. During annual reviews of load growth forecasts, NWS may be deployed, if available, to temporarily defer bus level load transfer projects. In the 2025-2029 rate period, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe area, which could help defer or avoid anywhere between 23 percent to 54 percent of the total load planned to be transferred. For further details, please refer to Section E7.2 Non-Wires Solutions.

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the overall cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2 (Selected Option): System Investments Aligned with Toronto Hydro's Station Load Forecast

Option 2 aligns with the Toronto Hydro's Stations Load Forecast which applies a probabilistic approach to forecast the peak loads of all the buses of the stations within the city of Toronto. The output of the forecast is arranged to reflect summer and winter peaks due to the different characteristics between the two peaking seasons. The primary drivers for load growth for the 2025-2029 rate period are Customer Connections, commercial transportation electrification, EVs and hyperscale data centres.

This investment option would relieve station capacity by transferring load away from heavily loaded areas. This option also invests in cable upgrade, feeder transfers, equipment upgrades and civil enhancements in highly loaded areas with a focus of relieve overloads under a first contingency basis. As part of this option, Toronto Hydro will also consider utilizing NWS as a mitigating tool to defer bus-level load transfers where applicable.

Efforts under this option will provide capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with sections 3.3.1 and 4.4.1 of the DSC with regard to prudent and efficient distribution system management.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term, as well as considering expected electrification needs that have a significant impact to Toronto Hydro's distribution system. With this option, Toronto Hydro can comply with the DSC and improve customer service, reliability, and safety of the system.

E5.3.5.3 Option 3: System Investments Aligned with Future Energy Scenarios High Electrification Scenario (Customer Transformation Low)

This option looks to invest in accordance with the Future Energy Scenarios model Consumer Transformation Low ("CT Low") Scenario which accounts for high electrification needs while assuming low efficiency.[33] Based on the CT Low scenario, the amount of bus-level load transfers will increase by 117 percent when compared to Option 2. Additionally, compared Option 2, the number of highly loaded feeders will increase by 42 percent, the number of network equipment upgrades will increase by 120 percent and the expected stations requiring additional civil egress work will increase by 50 percent. Based on these increases, this will result in an increase cost of approximately $206 million when compared to Option 2.

This option would allow for extensive relief in line with a more aggressive load growth. However, there is a higher risk of overbuilding the system if aligning with this option. While it is not recommended to proceed with this option, this analysis does provide insight into the degree of variability in load growth depending on how electrification trends and customer behaviours materialize in the 2025-2029 rate period.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program.

1. **Uncertainty of Future Load Growth**

Based on studies and analysis, the Station Load Forecast considered factors with a probabilistic approach when forecasting for peak loads of all Toronto Hydro buses of the station within the City of Toronto. Potential risks could arise based on future city planning changes or changes to redevelopment areas which could impact the load growth for the area. Such uncertainties can be mitigated by monitoring trends and updating forecasting accordingly and increasing flexibility when prioritizing and deploying work under the Load Demand program. Another strategy for managing

[33] Exhibit 2B, Section D4.

unexpected growth is the use of NWS such as local DR to shave peak loads. NWS can be implemented to incentivize customers to help reduce bus peaks. This type of NWS provides temporary relief, to provide flexibility to allow the time to implement more permanent solutions such as equipment upgrades or load transfers. Therefore, capital investments will still need to be made in the Load Demand program to support this growth.

2. Increasing Complexity of Projects

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs. Toronto Hydro has included preliminary inspections and design during up-front project creation in order to better scope out each project, leading to less variation in scope, costs and timelines as projects progress from planning to execution and construction.

3. Challenges Coordinating with Third Party Utilities

Moratoriums and third-party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third-party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

5.4 Metering

E5.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 87.4	**2025-2029 Cost ($M)**: 247.9
Segments: Revenue Metering Compliance; and Wholesale Metering Compliance	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness	

The Metering program (the "Program") funds investments in the utility's metering technology to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. The Program consists of two segments: Wholesale Meter Compliance and Revenue Meter Compliance.

The Wholesale Meter Compliance ("WMC") segment involves the planned upgrades of wholesale meters at transmission supply points.

The Revenue Meter Compliance ("RMC") segment involves the installation of meters for new customers, the replacement of meters approaching seal expiry, the planned replacement of residential and small commercial smart meters with next generation smart meters (commonly referred to as Advanced Metering Infrastructure ("AMI") 2.0, and upgrades for supporting metering infrastructure. The segment is comprised of specific initiatives that impact all of Toronto Hydro's customers. A substantial part of this segment involves the planned replacement of Toronto Hydro's population of AMI, including residential and small commercial smart meters under the AMI 2.0 deployment.

The Program and its constituent segments are a continuation of the activities described in the Metering program in Toronto Hydro's 2020-2024 rate application.[1]

The Program's primary objectives are to maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act* ("*EGIA*"), *Weights and Measures Act*

[1] EB-2018-0165, Exhibit 2B, Section E5.4.

(“*WMA*”),[2] and the *Independent Electricity System Operator’s (“IESO”) Market Rules* (which Toronto Hydro must abide by as a Market Participant), while facilitating accurate customer billing and supporting utility’s financial obligations.[3] In addition, as summarized in Section 1.6.1.1 of Grid Modernization, the deployment of AMI 2.0 is in line with Toronto Hydro's grid modernization objectives, as it lays a strong foundation for advanced and intelligent grid infrastructure. The abundance of data that accompanies the deployment of AMI 2.0 opens up opportunities for enhanced grid observability and situational awareness. The increased granularity of data collected through advanced meters will enable more robust data analytics, unlock new possibilities for grid optimization, and promote proactive asset management, customer engagement, and the implementation of non-wire solutions (“NWS”) such as flexibility services. AMI 2.0 will also play an important role in enhancing outage management and grid reliability by introducing new functionalities like “last gasp”, which enables grid operators to identify outage locations and dispatch repair crews to more precise locations.

E5.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro’s customer focus objectives by: ○ Maintaining billing accuracy of at least 98 percent by: (a) upgrading and replacing metering infrastructure and limiting the percentage of meters past their useful life and (b) completing metering system upgrade initiatives that reduce estimated bills and bill corrections; and ○ Installing ION meters for large industrial and commercial customers to enable customers to monitor energy consumption and power quality in real-time.

[2] R.S.C., 1985, c. E-4 [“*Electricity and Gas Inspection* Act”]. and R.S.C., 1985, c. W-6 [“*Weights and Measures Act”].*
[3] Independent Electricity System Operator, *IESO’s Market Rules & Manuals*, Chapter 6 and Chapter 4, 6 Appendices.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing meters with last gasp functionality which enables grid operators to identify outage locations and dispatch repair crews to more precise locations, which reduces operational costs and results in a quicker and more accurate response. ○ Enhancing data granularity (e.g. demand data, asset health data) which improves grid reliability by enabling the development of analytical tools that serve to proactively monitor asset health and identify maintenance needs and ultimately, reduce likelihood of unexpected equipment failure.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Maintaining compliance with various requirements such as Measurement Canada's *Electricity and Gas Inspection Act* and Regulations, the *Weights and Measures Act,*[4] and the *IESO's Market Rules* to enable accurate and timely meter reading, billing and market settlements.[5]
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner. • Enhanced measurement capabilities will allow for the development of enhanced analytical insights, including new types of predictive and prescriptive analytics, providing opportunities to improve the cost-effectiveness of planning and operational decisions.

E5.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Failure Risk, Business Operations Efficiency, Reliability

[4] *Supra* note 2
[5] *Supra* note 3

E5.4.3.1 Mandated Service Obligations

Metering in Canada is governed by the *Weights and Measures Act* ("*WMA*") and the *Electricity and Gas Inspection Act* ("*EGIA*").[6] Measurement Canada has jurisdiction over the administration and enforcement of these Acts.

1. Wholesale Meter Compliance

Toronto Hydro plans to upgrade its wholesale revenue meters to comply with the metering standards mandated by *IESO's Market Rules*[7] and Measurement Canada. Wholesale revenue metering upgrades require approved instrument transformers, de-registering the existing wholesale revenue metering points, preparing the site for new compliant wholesale metering equipment, overseeing the wholesale revenue metering installation work, and completing the registration process with the IESO. In 2020, Toronto Hydro completed its Wholesale Metering conversion on its existing grid supply points to comply with *IESO's Market Rules*.[8] For the 2025-2029 rate period, Toronto Hydro plans to continue its work on all new applicable wholesale metering points.

2. Revenue Metering Compliance

The *WMA* and *EGIA* and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage, and require that all meters must be resealed at specified intervals to ensure that a customer's electricity usage is metered accurately.[9] Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced.

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters. If the statistical accuracy results from the sample testing are within acceptable levels, all the meters in the meter group will receive a seal extension.

The regulatory framework also requires certain meters that do not fall under the sampling program to be removed for individual testing (reverification) and replaced with new meters.

[6] *Supra* note 2.
[7] *Supra* note 3
[8] *Ibid.*
[9] *Supra* note 2.

Once the seals of a meter sample group have expired, Toronto Hydro cannot use the meters in the group to bill its customers. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties, as contemplated by *EGIA*.[10]

All categories of meters (residential, commercial and industrial, large users, suite meters, wholesale meters) will either need to have their seals extended or be replaced throughout the 2025-2029 rate period. The bulk of residential and small commercial and industrial meters (which make up the significant majority of meters in Toronto Hydro's system) will have their seals expire between 2024 and 2026. Please see Figure 1 for a breakdown of the number of meters with seals expiring by year.

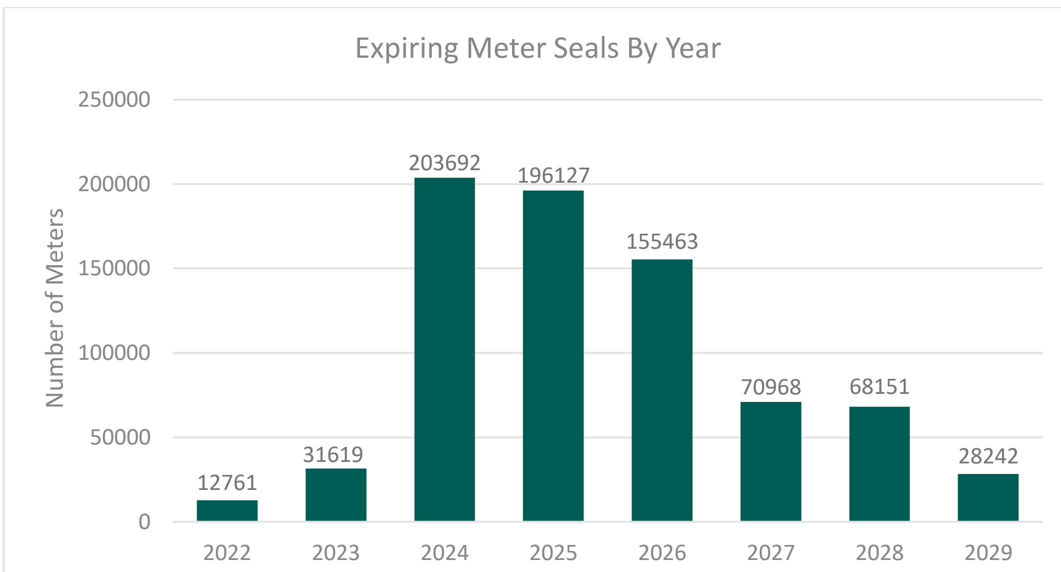


Figure 1: Expiring Meter Seals by Year

Customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes represent only 0.06 percent of Toronto Hydro's customers, yet they generate approximately 12 percent of the utility's total yearly revenue. These customers are typically key contributors to the economy of Toronto and Ontario, and can have loads that are sensitive to power quality issues. Examples of such customers may include auto manufacturers, office towers, entertainment complexes that host national and international audiences and sporting events, hospitals, and industrial manufacturing plants.

[10] *Ibid.*

Replacing meters currently in use by customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes at the time of meter reverification from non-ION to ION meters that have added functionality will allow for the diagnosis of customer power quality issues and may lead to a reduction in customer specific power interruptions. In addition, these meters provide three-phase power quality information that Toronto Hydro can use to investigate distribution system issues related to power quality, in order to take preventative actions to rectify system issues. These meters also provide direct benefits to the customers themselves by allowing them to monitor their energy consumption and power quality in real-time.

Figure 2: ION 8650 Meter Installed at Large User Sites

As existing meters for customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes reach seal expiry, Toronto Hydro will upgrade them from non-ION meters to ION meters. Toronto Hydro must also replace and reverify these meters as their meter seals expire. The planned ION installation schedule for the 2025 to 2029 rate period is outlined in Figure 3, below.

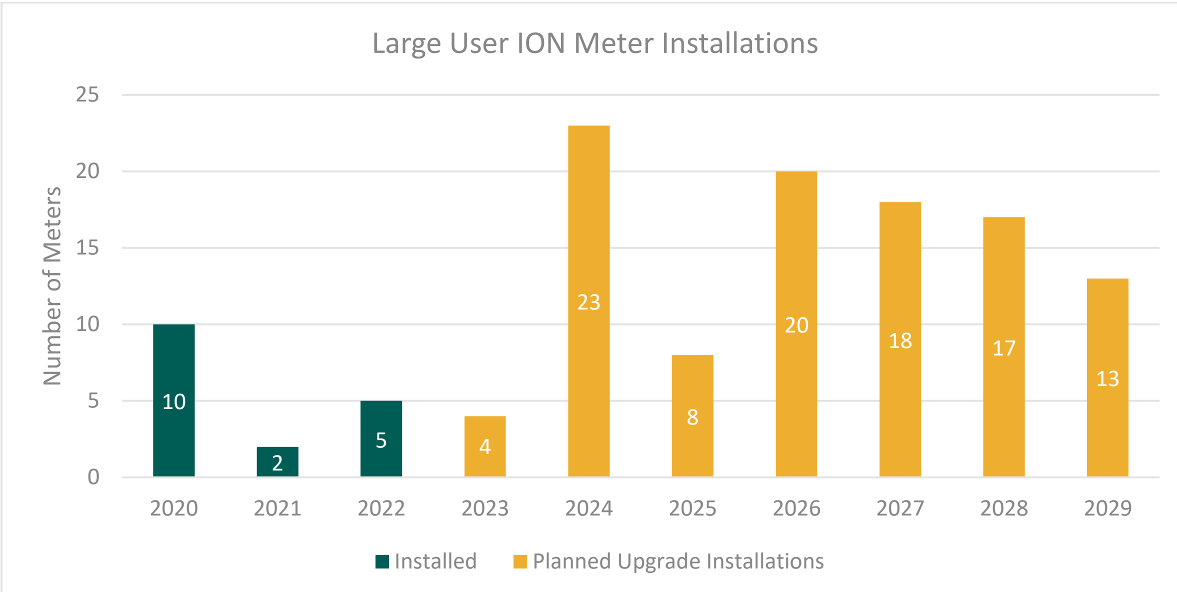


Figure 3: Large User ION Meter Installations by Year

a. <u>Suite Meter Installations</u>

Toronto Hydro is legally obligated to offer suite meter installation service. Utilities like Toronto Hydro offer this service in a competitive environment, and are also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider.

Currently, Toronto Hydro meters approximately 94,000 individual suites using suite meters, while also metering about 3,000 multi-residential buildings using bulk meters.

Throughout the 2025-2029 rate period, Toronto Hydro will continue to offer its suite metering services to new customers and retrofit upgrades with an expected average of approximately 2,000 new units every year. Toronto Hydro will also maintain the existing population of installed suite meters by reverifying and re-sealing the meters, as required.

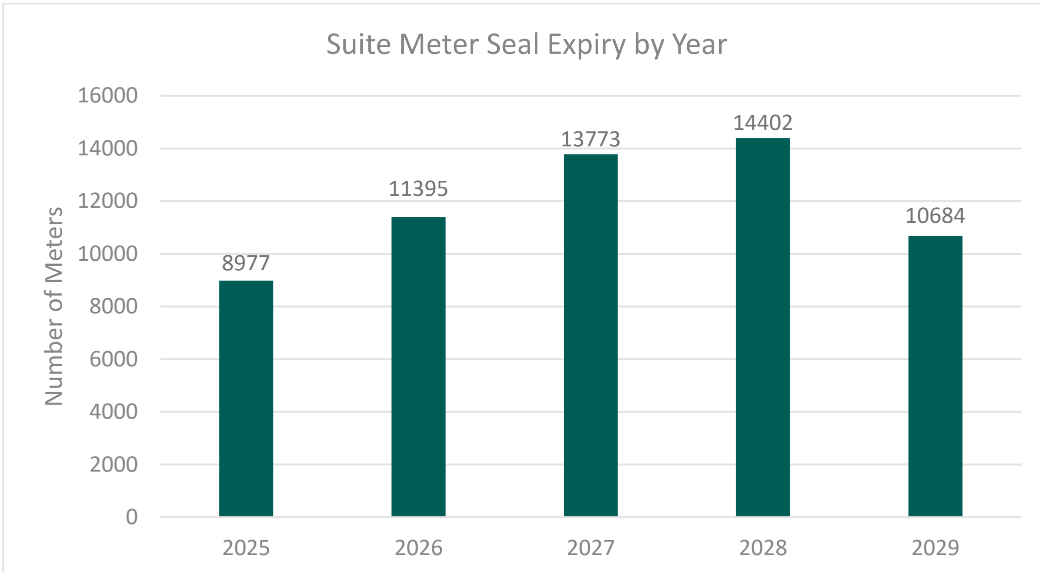


Figure 4: Suite Meter Seal Expiry by Year 2025-2029

b. <u>Continued Provincial Meter Data Management Repository ("MDM/R") Integration</u>

Toronto Hydro's billing systems were fully integrated with the provincial Meter Data Management Repository *("*MDM/R") by the end of 2018. During the 2025-2029 rate period, Toronto Hydro expects the IESO, in its capacity as the Smart Metering Entity ("SME"), to perform upgrades and annual enhancements to the MDM/R. For example, following recent amendments to Ontario Regulation 393/07, distributors will be required to transmit smart metering data relating to electricity conveyed into the distribution system as of January 1, 2025, which may drive further system modifications.[11] Toronto Hydro will need to ensure that its internal metering systems and Customer Care and Billing System ("CC&B") continue to communicate successfully and uninterruptedly with the MDM/R.

E5.4.3.2 Growth in Interval Meters

Efficient metering system is essential to manage Toronto Hydro's billing data in order to meet Ontario Energy Board ("OEB")'s prescribed billing accuracy targets and applicable metering requirements as per the Distribution System Code ("DSC"),[12] and ensure continuous vendor support.

[11] Ontario Regulation 393/07: Smart Metering Entity, made under *Electricity Act, 1998,* SO 1998, Ch 15, Sched A.
[12] Ontario Energy Board, *Distribution System Code* (August 2, 2023).

As the industry shifts towards electrification and decarbonization, the rise in the adoption of electric vehicles ("EVs") and distributed energy resources ("DERs") will increase customers' and stakeholders' expectations with respect to access to precise, hourly interval metering data to enable demand management, participation in the Industrial Conservation Initiative, and similar activities.[13] To facilitate this transition, Toronto Hydro will need to ensure it has adequate capacity to respond to the higher volumes of new metering installations and continue to comply with the applicable metering requirements as per *WMA*, *EGIA,*[14] and DSC in the 2025-2029 rate period.[15]

E5.4.3.3 Failure Risk

Toronto Hydro was among the first utilities to implement smart meters in support of provincial policy objectives, installing the bulk of its residential and small commercial meters between 2006 and 2008. As the meter population ages, the probability of meter failures increases. The rate of increase in failure risk accelerates as meters approach and surpass their expected lifespan, which is typically 15 years.[16] In 2021, segments of Toronto Hydro's meter population began to surpass the 15-year lifespan. By 2025, approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life as shown in Figure 5 below. Without proactive intervention, Toronto Hydro expects this trend to lead to accelerating rates of meter failure.

[13] Under the *Industrial Conservation Initiative*, Class A consumers can reduce the Global Adjustment portion of their bill if they are able to reduce or avoid consuming electricity from the provincial electricity grid during the top coincident peak hours of the year.
[14] *Supra* note 2.
[15] *Supra* note 11.
[16] Exhibit 2A, Tab 2, Schedule 1, Appendix D.

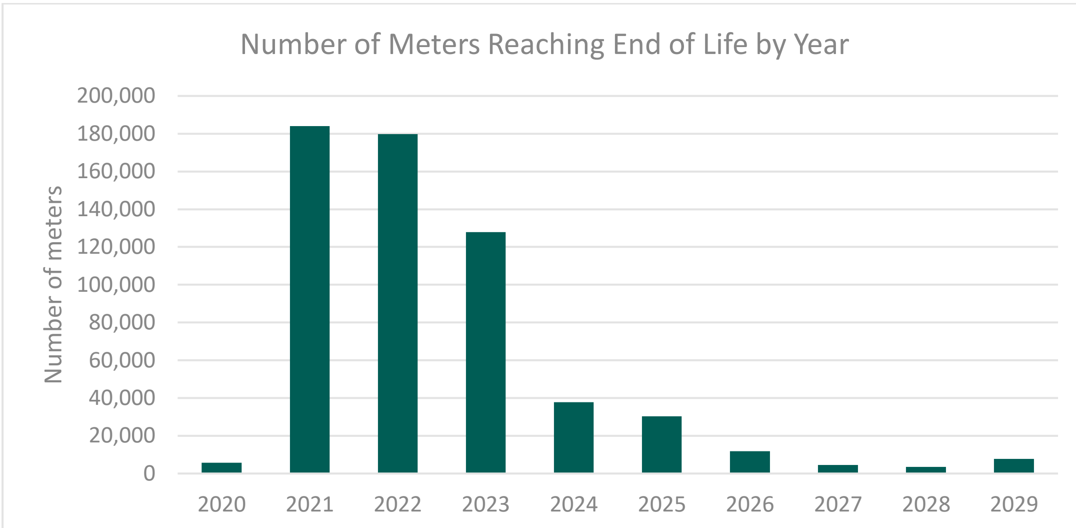


Figure 5: Residential and General Service <50 kW meters reaching end of life at 15-year lifespan

Failed meters have several negative consequences for utility operations and outcomes. When a meter fails, Toronto Hydro must estimate the customer's bill. Estimated billing decreases performance on OEB-prescribed billing accuracy targets, decreases customer satisfaction due to subsequent billing corrections, and undermines the utility's financial stability. Furthermore, replacing meters reactively is generally less cost-effective than doing so as part of a higher-volume planned program.

To address the growing population-wide risk of failure, Toronto Hydro intends to replace approximately 680,000 meters between 2023 to 2028. Meters will be replaced at or shortly following the end of their useful life of 15 years. In the process of renewing this significant population of end-of-life meters, the utility plans to introduce next generation smart meters and supporting network infrastructure, which – as discussed in the following section – will allow Toronto Hydro to increase the customer value derived from these assets through expanded capabilities.

E5.4.3.4 Business Operations Efficiency & Reliability

1. AMI 2.0

Metering technology plays a vital role in facilitating the efficient and effective operations of Toronto Hydro's system. A significant portion of Toronto Hydro's residential and small commercial meters were installed between 2006 and 2008, and rapid advancements in technology have rendered these first-generation smart meters outdated and obsolete. While the replacement of these meters is primarily driven by failure risk, advancements in metering technology have allowed for the adoption of incremental functionalities that directly align with Toronto Hydro's Grid Modernization strategy.

As shown in Figure 6, below, Toronto Hydro expects AMI 2.0 to deliver new capabilities beyond AMI 1.0, which was predominantly focused on meter-to-cash efficiencies. These new benefits include improved billing accuracy, faster outage response, improved network range, enhanced security against cyber-threats, increased grid transparency (e.g. system observability), and improved data granularity and analytical capabilities. In the longer term, Toronto Hydro intends to leverage the monitoring and control capabilities associated with AMI 2.0 to develop additional functionalities that could prove valuable in the management of an electrified and decarbonized energy system, including load disaggregation (e.g. tracking consumption by type of home appliance) and the potential integration of smart meters within the utility's DER management system ("DERMS" or "Energy Centre"). These evolving features are dependent on further technological developments.

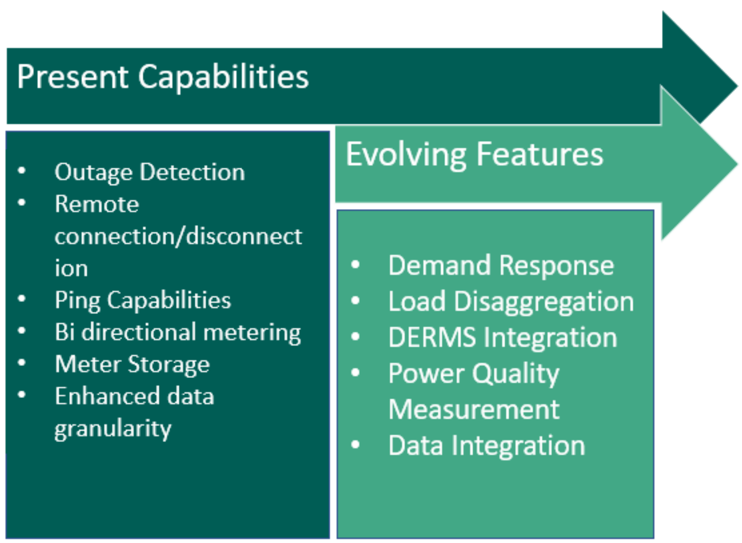


Figure 6: AMI 2.0 Use Cases: Expanded Capabilities

For a comprehensive overview of the role and expected benefits of AMI 2.0 in Toronto Hydro's modernization strategy, please refer to Section 1.6.1.1 of *Grid Modernization*. Three of the primary "out of the box" capabilities – last gasp, improved transmitting, and remote disconnect and reconnect – are highlighted below.

a. Last Gasp Functionality

Currently, Toronto Hydro is typically dependent on phone or service calls to define the location and boundaries of an outage. The utility's next generation smart meters will enable automatic outage and restoration notification (called "last gasp"). This capability will serve to reduce outage response times by deploying crews to the specified location sooner. See Figure 7, below, for a depiction of the operation of the "Last Gasp" functionality.

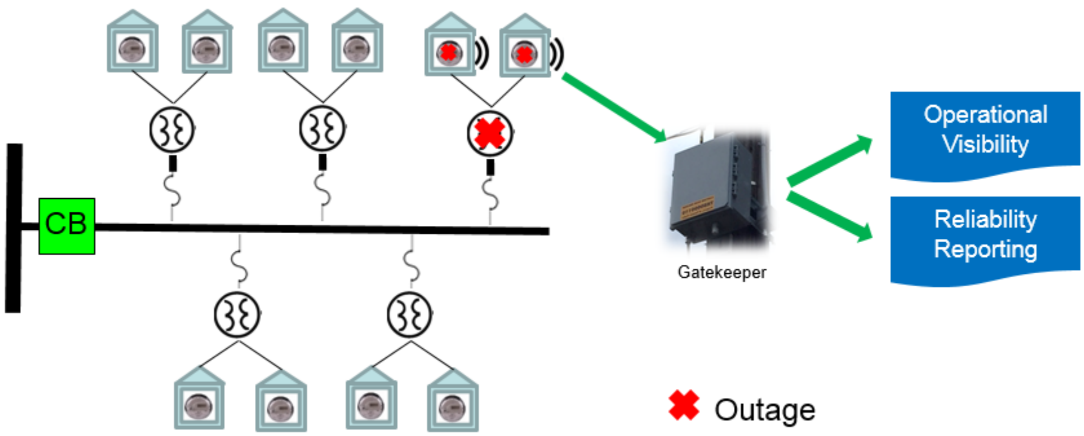


Figure 7: Last Gasp Function

b. Improved Transmitting

Another key feature of next generation meters is the presence of a more effective transmitter that will drastically increase the range and penetration of the meter signal. This is expected to increase the number of meters successfully read, reducing "orphaned" meters and the number of manual reads required, and further reducing the number of estimated bills issued, increasing Toronto Hydro's performance on OEB's bill accuracy metrics.

c. Remote Connection/Disconnection

Additionally, the introduction of meters with remote connection and disconnection capabilities allows Toronto Hydro to reduce the cost of performing disconnections and reconnections, due to the reduced need to dispatch field crew to a customer's property. This feature also enables customers to be reconnected soon after receiving payment, and allows for a more efficient and flexible implementation of OEB-prescribed reconnection standards. Toronto Hydro already completes all reconnections within two business days at least 90 percent of the time, as required by the OEB.[17] However, remote reconnection technology will significantly reduce reconnection timelines, which is more convenient to customers, therefore improving customer satisfaction.

2. Interval Metering system

Currently, Toronto Hydro uses the Interval Metering system, ITRON Enterprise Edition ("IEE" - the data processing system) and MV-90 (data collection system) to ensure efficient metering and support the interval data collection process for Toronto Hydro's interval metered customers (i.e. General Service at least 50 kW and above customers), respectively. Efficient metering is essential to manage Toronto Hydro's billing data in order to meet OEB prescribed billing accuracy targets and applicable metering requirements as per the DSC, and ensure continuous vendor support.

The utility will upgrade both systems to maintain vendor support. The IEE system is scheduled for an upgrade during 2023-2025 and again during 2028-2029. The MV-90 data collection system is also scheduled for upgrades during 2026-2027 to support better design, functionality and enhance the interval data collection process.

3. Residential Metering

Currently, Toronto Hydro's residential metering head-end system ("Connexo") is responsible for collecting and submitting measurement data and meter events to the meter data management ("MDM") systems. This system consists of two components, Connexo NetSense and Connexo FieldSense. Connexo FieldSense was implemented in 2022 and incorporates the software and hardware for field service management. The utility must continually upgrade its residential metering head-end system to maintain vendor support and the capability to enable features available on newer generation meters. By end of 2023, Toronto Hydro plans to implement a new version of Connexo NetSense, the residential metering head-end system which will be required to support the next generation meters (AMI 2.0). This upgraded version will allow for improved functionality – enabling enhanced communication features available in newer advanced meters and implementing a Gatekeeper (Collector) replacement program. More importantly, the new generation of meters will reduce the number of manual meter reads and estimated bills. This will also allow Toronto Hydro to

[17] *Supra* note 11, Section 7.10.1.

continue to meet OEB-prescribed bill accuracy targets and improve customer satisfaction by limiting billing errors.

4. Suite Metering

The City of Toronto is experiencing significant development of condominiums and other high-density buildings. As a result of this customer growth, by the 2025-2029 rate period Toronto Hydro's current suite meter AMI system ("Primeread") will no longer be able to retrieve and process the suite meter data fast enough on a daily basis to meet meter reading and billing performance targets mandated by Measurement Canada and the IESO. As a result, Toronto Hydro intends to upgrade its data collection system, Suite Meter Advanced Metering Infrastructure ("AMI") to i) ensure continuous vendor support, ii) improve Toronto Hydro's operations, including timely and accurate billing resulting in higher customer satisfaction, ability to meet OEB-prescribed bill accuracy metric (by reducing estimated billing and manual reads); and iii) improve financial stability. The lifecycle of the Suite Metering AMI has a scheduled upgrade roughly every three years to keep up with the influx of new suite metered customers. Primeread was initially brought online in 2012, the first upgrade took place in 2015, followed by 2017. The next upgrade is scheduled in 2023 and then again during 2027-2028.

5. Operational Data Storage Upgrade ("ODS")

Presently, ODS is used for framing consumption data for billing and for automated validation, editing and estimating meter data. ODS transfers consumption data from meters into Toronto Hydro's CC&B for billing and ensures timely and accurate billing for customers. The transfer of consumption data from ODS to CC&B is crucial to complete the annual rate reclassification process, as mandated by OEB Distribution System Code. The upgrade scheduled for 2024-2026 will enhance the ODS to better manage Toronto Hydro's billing data to meet OEB prescribed billing accuracy targets and ensure continuous vendor support. The subsequent upgrade for ODS is scheduled for 2029. These upgrades would also accommodate any new price plan introduced by OEB.

E5.4.4 Expenditure Plan

Toronto Hydro's historic and forecast spending in the Program is shown in Table 4, below. Expenditures in the Program are largely driven by the timing of metering and metering system upgrade cycles.

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Metering	11.2	8.1	8.4	9.0	50.7	63.7	69.9	72.4	34.7	7.4

The majority of costs in 2020 is attributed to work related to wholesale metering compliance. The bulk of spending over 2021-2023 has been driven by upgrades to meter data and related field services systems to retain vendor support, meter replacements and reverification related to revenue metering compliance, and suite metering costs. To address funding constraints over the 2020-2024 rate period, Toronto Hydro deferred the majority of meter replacements to the 2025-2029 rate period, when it plans to replace meters at their seal expiry year. In addition, delays in procuring AMI 2.0 meters required the utility to adjust the pace of replacements through its sampling and reverification program by extending the seal life for meters with seals expiring in 2023 by six years. During the 2020-2024 rate period, Toronto Hydro plans to replace approximately 50,000 residential, small commercial, and industrial meters, as part of the AMI 2.0 project. Starting in 2024, program costs are forecasted to increase, primarily driven by the resumption of deferred meter replacements for residential, small commercial, and industrial meters, including the installation of next generation meters as part of AMI 2.0. During the 2025-2029 period, Toronto Hydro plans to replace approximately 630,000 meters.

Although the replacement of these meters is primarily driven by failure risk, the advancements in technology have allowed for the adoption of advanced functionalities. These meters will allow Toronto Hydro to expand the functionality of its metering population, through wider interoperability using a standards-based solution, greater options for remote meter disconnect and reconnect, distributed intelligence, cloud and data analytics, advanced outage detection, integrated distribution automation network support, remote power quality monitoring, and personalized customer communication.

Table 5, below shows the detailed breakdown of Program spending over the 2020-2024 rate period.

Table 5: Actual & Bridge Program Costs 2020-2024 ($ Millions)

	2020	2021	2022	2023	2024	Total
Residential and Small C&I Meter Replacement	0.44	0.05	1.74	3.39	43.63	**49.24**
Suite Metering	1.84	1.80	1.02	1.21	1.19	**7.06**
Large Customer and Interval Metering	0.12	0.02	0.03	0.05	0.34	**0.55**
Remote Disconnect	0.78	0.76	0.33	0.31	0.31	**2.50**
Sampling/Meter Replacement	4.19	3.58	2.88	1.53	2.92	**15.10**
Wholesale Metering	1.66	-0.02	0.14	0.30	0.70	**2.79**
System Upgrades	2.19	1.89	2.31	2.20	1.60	**10.19**
Total	**11.2**	**8.1**	**8.4**	**9.0**	**50.7**	**87.4**

Table 6, below, provides a breakdown of Toronto Hydro's forecast expenditures over the 2025-2029 rate period. This forecast is based on the number of meters that will need to be resealed or replaced in each year to ensure compliance with Measurement Canada and *EGIA* requirements.[18] In addition, Toronto Hydro must continuously monitor and manage the risk of asset failures associated with meters past their end-of-life by replacing meters at or shortly following their useful life of 15 years with next generation smart meters and supporting network infrastructure, as part of AMI 2.0. Lastly, the forecasted plan allows Toronto Hydro to increase the customer value derived from these assets through expanded capabilities that can be leveraged to meet future changes in customers' needs and preferences. Costs for metering system upgrade initiatives are based on a paced installation schedule using currently available cost estimates.

As shown below, the greatest increase in Toronto Hydro's forecast spending over the 2025-2029 rate period compared to historical spending over the 2020-2024 rate period is seen in the residential and small commercial meter replacement category. This increase is primarily attributed to the meter replacement initiative under the AMI 2.0 deployment (See Options Analysis section for additional details). With respect to suite metering, although the total cost is decreasing over the five-year period, the total cost is higher than for the 2020-2024 rate period to support the expected average growth of approximately 2,000 new units every year. With respect to Wholesale Metering, initially, the wholesale metering upgrade at Charles TS was scheduled within the 2020-2024 rate period. However, based on a cost benefit analysis, Toronto Hydro made the decision to move this upgrade

[18] *Supra* note 2

to the 2025-2029 rate period, as part of the scope of Hydro One's planned power transformer replacements.

Table 6: Forecast Program Costs 2025-2029 ($ Millions)

	2025	2026	2027	2028	2029	Total
Residential and Small C&I Meter Replacement	54.5	58.9	62.2	26.0	0.0	**201.6**
Suite Metering	2.1	1.9	1.8	1.7	1.6	**9.1**
Large Customer and Interval Metering	0.2	0.7	0.3	0.3	0.2	**1.7**
Sampling/Meter Replacement	4.9	4.2	5.0	3.9	3.2	**21.2**
Wholesale Metering	0.0	1.5	0.0	0.0	0.0	**1.5**
System Upgrades	2.0	2.6	3.0	2.9	2.4	**12.8**
Total	**63.7**	**69.9**	**72.4**	**34.7**	**7.4**	**248.1**

E5.4.5 Options Analysis

E5.4.5.1 Options for Revenue Meter Compliance

The Revenue Meter Compliance segment includes many tasks that must be completed in order to remain in compliance with Measurement Canada requirements. This includes the meter replacements for residential, suite meters, interval meters, and large users and metering system upgrades. These projects must be completed to ensure continued compliance with Measurement Canada and OEB requirements. For example, for the interval and suite metering projects, Toronto Hydro must maintain the meter seals to ensure continued compliance with requirements contained in the *WMA* and the *EGIA*.[19]

The major project for the Revenue Meter Compliance segment over the 2025-2029 rate period is the residential and small commercial meter replacement under the AMI 2.0 deployment. The AMI 2.0 project is slated to commence in the 2020-2024 rate period, and will continue throughout the 2025-2029 rate period. The options for the 2025-2029 rate period revolve primarily around the pace of meter replacements under the AMI 2.0 project, and only consider the costs associated with residential and small commercial meter replacement. If meters with expired seals are not replaced before their seal expiry, their seals will be extended through the sampling and reverification program under each option. This project has four options for completion, which are discussed in detail below.

[19] *Supra* note 2.

1. Option 1: Replacement of meters beyond their 15-year useful life

This option replaces meters in their second seal period, which is generally beyond their 15-year useful life. This option is the least capital intensive of the four, as it defers the meter replacement to a future period. Although this option is the most financially feasible, meters would remain in operation for the longest period of time, and beyond the useful life, posing considerable operational, regulatory and financial risks. As well, this option does not replace the entire population of AMI-included models by the end of 2029.

As most of the meters are replaced past their end of useful life under this option, it poses a risk of failure for these aging meters. Substantial meter failures would have a significant negative impact on Toronto Hydro's operations, including lack of timely and accurate billing resulting in lower customer satisfaction, inability to meet OEB-prescribed bill accuracy metric and financial instability. A reactive approach to replace the meters that have failed would result in an increase in Toronto Hydro's operational costs which would need to be addressed through the redirection process, thereby placing other forecasted investments at risk.

The total cost of this option for the 2025-2029 rate period is $163.0 million.

2. Option 2: Replacement of meters beyond their 15-year useful life while mitigating risk of asset failure

Option 2 has a greater emphasis on mitigating the risk of asset failures associated with meters past their end-of-life. Under Option 2, meters would be replaced earlier than Option 1, resulting in the replacement of more meters in the 2025-2029 rate period than under Option 1. Under Option 2, however, a portion of the original AMI meters would remain in the field delaying the achievement of Last Gasp functionality. Last Gasp functionality cannot be enabled until the majority of meters are replaced with newer models. Also, Toronto Hydro will not be able to capture the entire benefits of AMI 2.0 meters until the majority of the current meters are replaced.

The total cost of this option for the 2025-2029 rate period is $182.7 million.

3. Option 3: Replacement of meters as they reach seal expiry

The primary focus of this option is to replace meters as they reach seal expiry, regardless of their age or seal period. This option will pose a greater risk for resource balancing as it requires a large number of meters to be replaced in 2025.

As this option does not prioritise meter replacements based on meters past their end-of-life, this will pose a greater risk of failure for meters past end-of-life which may result in additional operational cost for field activities and manual billing of the customer. A reactive or ad hoc approach to meter replacement also requires more operational costs, compared to a planned replacement.

The total cost of this option for the 2025-2029 rate period is $199.0 million.

4. Option 4: Replacement of the entire fleet of meters (Preferred Option)

Under option 4, the entire fleet of AMI meters would be replaced during over 2023-2029. The replacement schedule would be identical to Option 2 for meters that have reached their end-of-life by 2029 plus those that have an end-of-life beyond 2029 would be added in.

This pacing option adequately achieves all of the intended objectives of the replacement such as the seal expiry issue and potential risk of meter failure beyond end-of-life, while mitigating any operational, regulatory and financial risks. This option also aligns with Toronto Hydro's grid modernization and customer experience strategic objectives as it enables the earliest attainment of out-of-the-box benefits compared to all other options. Benefits include remote disconnect and reconnect and the earliest achievement of Last Gasp functionality. Option 4 also lays the groundwork for the implementation of other advanced capabilities that will require further investments in technology (e.g. DERMS), development of organizational capabilities (e.g. advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized (See Figure 6 above – AMI 2.0 Use Cases: Expanded Capabilities for more details).

Given these considerations, Toronto Hydro has selected Option 4 as its approach.

The total cost of this option for the 2025-2029 rate period is $201.6 million.

5. Options Comparison

Option 4 is selected based on the following criteria as summarized in Table 7:

- **Lowest number of projected meter failures associated with assets past end-of-life**: The proposed replacement strategy in Option 4 and Option 2 is expected to have the lowest number of meters past their life expectancy in the 2025-2029 rate period. Delaying the replacement of meters beyond their useful life of 15 years can lead to an increased risk of meters failure. As a result, there is an increased risk of non-compliance with the *EGIA*,[20] the OEB-prescribed performance metric pertaining to bill accuracy and *IESO's Market Rules* regarding market settlements.[21] In addition, responding to meter failures that occur before their scheduled replacement can result in increased operational costs (e.g. billing exceptions that require manual intervention and additional field activities to investigate the failures). Additionally, a reactive or ad hoc approach to replacing meters that have failed can result in higher operational costs that would need to be redirected, placing other forecasted investments at risk.

- **Earliest achievement of Last Gasp functionality**: Next generation meters are equipped with this capability. This feature enables grid operators to identify outage locations and dispatch repair crews to more precise location, resulting quicker and more accurate response. It also enables emergency response and outage restoration activities that require customer level outage information. It is expected that this option will provide the fastest achievement of Last gasp capability.
- **Replacing entire fleet of meter models included in the AMI 2.0 project**: By replacing the entire fleet of AMI 2.0-included models, this option is expected to lay the groundwork to realize future advanced capabilities of AMI 2.0 meters. These advanced capabilities will serve to equip Toronto Hydro and its customers with new functionalities that are well-aligned with Toronto Hydro's Grid Modernization and Customer Experience objective and lay the foundation for the development of an intelligent grid (i.e. two-way interactive capabilities) and enhancing customer service (i.e. omni-channel view of the customer). The advanced capabilities of the AMI 2.0 meters will require further investment in technology (such as DERMS), development of organizational capabilities (such as advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized. (See above Figure 6 –AMI 2.0 Use Cases: Expanded Capabilities).

[20] *Supra* note 2.
[21] *Supra* note 3.

Table 7: Options Comparison

Option	Emphasis	Risk of asset failures past EOL	Investment Level	Replacing all AMI2.0 models by 2029
Replacement of meters beyond their 15-yr useful life	Minimize capital investment in the 2025-2029 period	Medium	Lowest	No
Replacement of meters beyond their 15-yr useful life while mitigating risk of asset failure	Minimize meters past EOL	Low	Medium	No
Replacement of meters as they reach seal expiry	Align replacement with seal expiry	High	High	Yes
Replacement of the entire fleet of meters (Preferred Option)	Minimize meters past EOL	Low	High	Yes

E5.4.5.2 Options for Wholesale Metering Compliance

For the Wholesale Metering Compliance segment, Toronto does not have any alternative options as the utility is required to complete the remaining Meter Service Provider ("MSP") conversions, in accordance with IESO's mandated requirements.

Toronto Hydro seeks new opportunities, through close collaboration with Hydro One Networks Inc., to 'bundle' any proposed Wholesale Metering Compliance initiatives with planned capital improvements. This includes replacements of any Hydro One power transformers and distribution equipment within the joint-use terminal stations.

E5.4.6 Execution Risks & Mitigation

The table below illustrates the major program risks that may occur while executing the Program.

Table 8: Meter Risks, Impact, Probability, and Mitigation

Project Segment	Risk	Impact	Probability	Mitigation

Revenue Meter Compliance	Execution/ Supply chain Risk for AMI 2.0 deployment	The Mass deployment plan for AMI 2.0 meters would have to be modified and timelines stretched. This would force Toronto Hydro to reseal meters past useful life, increasing capital expenditures and risk of failure	Low	• Ensure that enough lead time is provided to the vendor to ensure delivery of equipment as required.
				• Toronto Hydro will adopt the following mitigation measures to ensure contractual mechanisms are available as well as to oversee and enforce contract terms and conditions:
				  ○ Clearly state expected timelines and have resolution clauses to address delays.
				  ○ Identify an escalation path to quickly resolve conflicts and discrepancies.
				  ○ Enforce short interval control through vendor project status updates and reports.

Wholesale Metering	Hydro One projects enabling Toronto Hydro's required meter replacements are delayed.	Compliance with *IESO Market Rules* is affected or delayed.	Low – projects are complicated and subject to equipment delays and resource availability.	Work closely with Hydro One to schedule work and to allocate appropriate resources to metering compliance projects.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 11.2	**2025-2029 Cost ($M):** 35.0
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act, 1998* to connect Distributed Energy Resource ("DER") projects to its distribution system, which includes renewables like solar photovoltaic, wind and biogas.[1] It also allows Toronto Hydro to meet its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist of "renewable-enabling improvements".[2]

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting an increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029. To safely connect and monitor these DERs, Toronto Hydro plans to make the following investments in the 2025-2029 rate period:

- Generation protection measures, including the installation of bus-tie reactors at six station busses to alleviate short circuit capacity constraints; and
- Installation of 315 monitoring and control systems ("MCS") for renewable DER facilities greater than 50 kW to provide situational awareness and control of DER facilities on the distribution system.

[1] SO 1998, Ch 15 Sched A.
[2] Sections 1.2 and 3.3.2 of the DSC.

1 ## E5.5.2 Outcomes and Measures

2 **Table 2: Outcomes & Measures Summary**

Customer Focus	• Contributes to Customer Service objectives by: ○ Enabling the connection of new generation customers without extensive delays or adverse impacts to existing and new customers; ○ Complying with sections 25.36, 25.37 and section 26 of the *Electricity Act, 1998* by connecting DER customers to its distribution system; ○ Providing Toronto Hydro with the ability to observe larger DERs in real-time and enable the maximum allowable amount of generation to be connected to the grid.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring the operation of the distribution system remains within safe and allowable designed short circuit current limits by installing six bus-tie reactors on station buses; ○ Avoiding unintentional islanding and reducing the islanding risk of DER sources; and ○ Ensuring bi-directional flows remain within distribution system design parameters including thermal and short-circuit capability by installing MCSs at existing and new DER facilities.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and employee safety by: ○ Enabling automatic disconnection of DER from the grid in adherence to OESC Rule 84-008 ○ Provide the ability to both remotely and automatically isolate DER connections under specified conditions as part of work protection and EUSR rule requirements
Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system

3 ## E5.5.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Reliability, Customer Service Requests

Toronto Hydro is legally mandated to connect DER customers and provide generators non-discriminatory access to its distribution system.[3] The planned investments in this program qualify as Renewable Enabling Improvements in the DSC and will address certain barriers to connecting DERs, including short-circuit capacity constraints, increased risks of islanding, overloading the system and increased thermal ratings. Furthermore, by investing in real-time monitoring and control at customer DER sites, Toronto Hydro is continuing to lay the foundation for more advanced DER management use cases in the longer-term.

The Program is fundamentally customer-driven. The proposed work will allow Toronto Hydro to connect customer DER projects to the distribution system through the Customer and Generation Connections program.

The planned investments are also critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably respond to the increasing demand of renewable DER facilities across the City of Toronto.

Figure 1 below shows typical DER installations on the Toronto Hydro distribution system, as enabled by investments in this Program.

Figure 1: Residential (left) and Commercial (right) DER Installation

[3] See: Sections 25.36, 25.37 and 26 of the Electricity Act, 1998; Section 6.2.4 of the Distribution System Code; Section 6.1 of Toronto Hydro's Distribution License.

E5.5.3.1 Proliferation of Distributed Energy Resource Facilities

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting a continued increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029.[4]

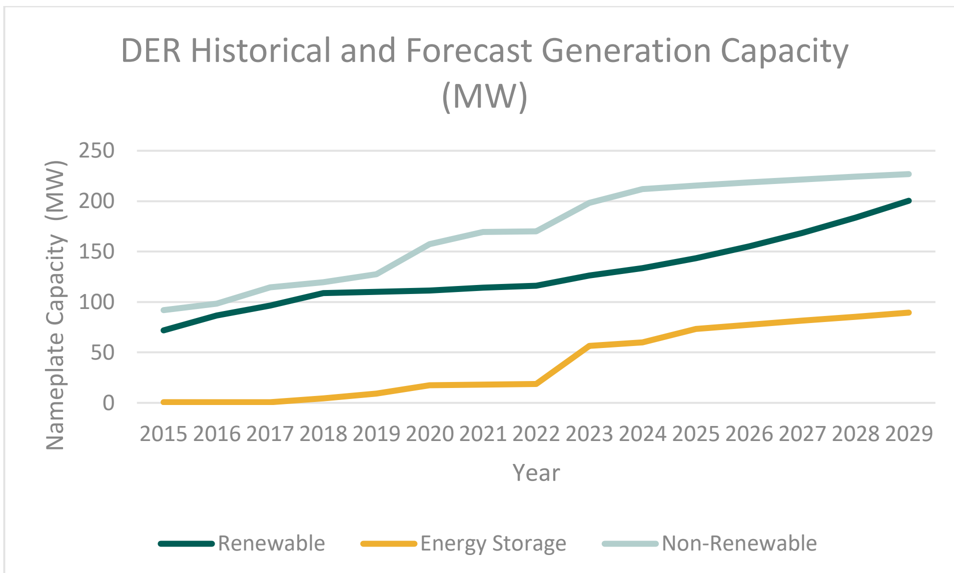


Figure 2: Historic and Forecasted Generation Capacity 2015-2029

As discussed in detail in the Generation Connection segment at section E5.1.3.2, this forecast is subject to uncertainty. As a customer-driven program, the uptake of DERs is affected by customer behaviour and other external factors, including policy and technology developments. For example, the cancellation of the Feed-in-Tariff ("FIT") program in 2018 resulted in a sharp decrease in renewable DER applications after a period of high year-over-year increases. Between 2009 to 2018, Toronto Hydro saw a compound annual growth rate of 33.93 percent, peaking in 2011 with a more than 89.9 percent increase in generation installed compared to 2010. From 2019 to 2022 the compound annual growth rate fell to 1.84 percent.

Looking ahead, the results of Toronto Hydro's Future Energy Scenarios modelling effort depict a wide range of DER uptake scenarios for the next decade and beyond. For example, at the very high end, the Future Energy Scenarios model shows that achieving Net Zero by 2040 in accordance with the City of Toronto's current strategy could involve increasing renewable penetration on Toronto

[4] See EB-2023-0195, Exhibit 2B, Sections E3 and E5.1 for a discussion of the DER forecasting methodology.

Hydro's grid to an estimated 1,249 MW by 2029. This would represent an increase of 974.9 percent of DER capacity on the grid. Hosting this level of DERs while also facilitating the full realization of coordinated DER benefits for the grid could require significant investment in hosting capacity expansion, grid modernization, and innovation.

In order to manage the inherent uncertainty of forecasting these connections, Toronto Hydro regularly reviews DER connection trends to evaluate where system constraints will emerge.

E5.5.3.2 System Capability to Connect and Control Distributed Generation

Toronto Hydro supports connecting DERs to the distribution system in alignment with the DSC and in coordination with Hydro One and the Independent Electricity System Operator ("IESO"). The utility has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work.

Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Failures due to distribution system stresses from DER sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic tripping and other similar effects.

Toronto Hydro must manage the capacity and type of generation connected to both feeders and stations to ensure reliable operation and prevent damage to existing infrastructure. Introducing increased levels of bi-directional flows from DER will require protection, monitoring, and control to prevent such occurrences during normal operation, planned work and emergency situations.

At this time, there is a limited set of options for addressing DER constraints. As part of its Grid Modernization Roadmap and in anticipation of a high-DER future, Toronto Hydro is investigating and pursuing technologies and solutions that can provide for incremental flexibility in DER integration, including through more predictive and dynamic forms of DER management within grid operations.[5] For example, the energy storage systems (ESS) program is expanding to deploy grid-side batteries to (1) relieve system constraints thereby enabling more renewable hosting capacity on the grid; and (2) respond to the dynamic output of renewable energy sources by acting as a load-generation buffer in periods of mismatch. Furthermore, advances in the Advanced Distribution Management System

[5] See EB-2023-0195, Exhibit 2B, Section D5 for Grid Modernization Roadmap.

("ADMS") and Distributed Energy Resource Management System ("DERMS"), which are systems designed to provide a holistic view of the grid and optimize operations through real-time telemetry and control algorithms, can also enable DER utilization at a higher capacity factor and in turn, allow DERs to participate in grid services at more dynamic and granular levels.

1. Short Circuit Capacity Limitations

Short circuit limits on both the Toronto Hydro and Hydro One system are important factors in determining how much DER can be connected to Toronto Hydro's distribution system. This is because short circuit capacity is the measure that ensures certain power distribution assets are within their recommended withstand thresholds. The primary limiting element for short circuit capacity is substation equipment (where fault current levels are highest) and, more specifically, substation load side breakers.

Currently, three station buses have reached short circuit capacity limits and are not able to connect additional DERs. Toronto Hydro anticipates that a total of eight station busses will exceed short circuit capacity by 2029.

Table 4: Current and Forecasted Short Circuit Capacity

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Ellesmere	H9-J	81.0	-5.4
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Sheppard	47-EZ	-57.3	-91.4
Woodbridge	D6-BY	-27.3	-28.0

To arrive at the projected constraints in Table 4, Toronto Hydro mapped its overall forecast of 2029 DER capacity onto station busses by assuming that the geospatial distribution of DERs will continue to follow existing load connection patterns.

Toronto Hydro manages short circuit capacity limitations through two methods: 1) bus-tie reactors; and 2) increased fault levels. Each of these is described in further detail below.

Note that traditional station expansions investments can also relieve short circuit capacity limitations by introducing distribution equipment with higher capacity or greater short circuit withstand limits. However, given the significant cost and time involved, it is not economical to expand a station solely for the benefit of connecting DERs. Rather, increased DER connection capacity can be considered a secondary benefit of planned station expansions, which will be required in the normal course to accommodate increasing load demand in specific regions of the city. For example, the planned expansion of Sheppard TS will have the secondary benefit of helping to alleviate the existing short circuit constraint. The remaining station busses forecasted to require relief as described above will not, however, be addressed through stations expansion investments.

a. Bus-Tie Reactors

To facilitate DER connections, bus-tie reactors can be installed on the bus to mitigate high fault current levels. This technology lowers short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DER capacity. The actual size of a reactor depends on site specific constraints such as space, etc. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

Toronto Hydro has engaged Hydro One to coordinate bus-tie reactor installations at stations where fault current constraints have become or are likely to be an issue in the near future. Based on current forecasts, of the eight stations requiring relief by 2029, Toronto Hydro anticipates installing six bus-tie reactors over the 2025-2029 rate period to alleviate short circuit capacity constraints, as summarized in Table 5: Bus Tie Reactor Installations below.

Of the remaining two stations, Sheppard TS would not be a good candidate for a bus-tie reactor due to its use of a gas-insulated bus but has potential upcoming station expansion work that could also increase short circuit limits at the station. For Ellesmere TS, the short circuit constraint may be addressed using an alternative measure described below.

Table 5: Bus Tie Reactor Installations

Station Name	Bus	Year
Richview	88-BY	2025
Runnymede	11-JQ	2026
Cecil	CE-A1A2	2027
Esplanade	X-A1A2	2028
Leslie	51-BY	2029
Woodbridge	D6-BY	2029

b. Increased Fault Level for 27.6 kV Stations

Another solution to short circuit capacity constraints, in some limited circumstances, is operating at an increased fault level. There is no cost associated with operating at the increased fault level, but it is deemed to be a temporary solution due to the minimal short circuit capacity it relieves. Currently, Toronto Hydro operates at 16.7 kA fault level for stations operating at 27.6 kV. The Transmission System Code provides that 27.6 kV stations may operate at a fault level up to 17 kA, creating additional short circuit capacity.[6] Hydro One must approve an application from a distributor to

[6] Appendix 2 of the TSC.

operate at a higher fault level. The solution is only available where customers' equipment fault withstand ratings are verified to be within safe limits, particularly for those customers closest to the station.

Toronto Hydro determined that of the eight stations expected to experience short circuit constraints by 2029, only one bus, Ellesmere TS J bus, met the criteria for operating at the increased fault level without impacting the reliability of connected customers.

E5.5.3.3 System Monitoring to Control Distributed Generation

Lack of monitoring and control over distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

Currently, Toronto Hydro requires MCSs for DER installations that are equal to or greater than 50 kW. This accounts for almost 95 percent of the total DER capacity connected to Toronto Hydro's grid. This threshold ensures that Toronto Hydro has enough visibility and management of DERs to achieve the objectives of the Program at a reasonable cost.

1. Anti-Islanding Condition for Distributed Energy Resources

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available due to a fault condition. This can create dangerous back-feed on the distribution system, exposing workers to live circuits that they believe are de-energized. This can also interfere with grid protection systems and damage equipment after utility power is restored.

Monitoring and control can mitigate the risks associated with DER for the public and Toronto Hydro field personnel. Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") requires that DERs have back-feed protection so that in the absence of electrical power (potential) on the utility's supply, DERs cannot energize the utility's supply. If the anti-islanding feature of a DER were to fail, it would back-feed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel, and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing a remote electronic trip or shutdown command when the feeder breaker is opened.

The connection of PV solar inverters and other DER sources must be accomplished in a manner that ensures that unintentional islanding of DER sources cannot occur. Through the MCS equipment logic that reverts the Remote Terminal Unit ("RTU") contact of the remote disconnect device after loss of power from the UPS, islanding conditions are averted. Toronto Hydro plans to continue to deploy real-time monitoring and control investments proposed within this Program at new DER sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*"[7] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DER in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of eleven distribution feeders have ratios ranging from 0.30 to 11.51 (refer to Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
63-M6	Agincourt	Y	3.6	7.6	0.47
53-M3	Bermondsey	B	0.6	2.1	0.30
80-M10	Fairchild	Y	1.4	2.2	0.63
55-M31	Finch	J	1.8	3.6	0.48
R30-M3	Horner	B	0.8	1.7	0.45
38-M4	Manby	F	0.6	0.0	11.51
R29-M5	Rexdale	B	0.9	2.5	0.36
A-35-T	Strachan	A7A8	1.0	0.5	1.99

[7] Institute of Electrical and Electronics Engineers.

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R43-M31	Warden	J	0.8	2.4	0.35

The forecasted 516.7 MW cumulative of DER capacity anticipated by the year 2029 will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DER to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DER if they unintentionally island. If the generation to minimum load ratios are not addressed by proactive investments in control and monitoring capabilities, they could ultimately limit the number of DERs Toronto Hydro is able to connect to the system. These systems also provide greater visibility into the grid and allow the utility to enable more DERs to connect, as explained in section E5.5.3.3.

2. System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DER by ensuring system loading thresholds are satisfied. Exceeding system loading limits, as seen in Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third, sacrifices the life of distribution equipment and can cause immediate equipment failure as mentioned earlier.

For large sized generation connections or the aggregation of small and medium sized generation connections, limiting a feeder's continuous load thermal ratings is an important operating condition. Feeder planning and operation account for the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with factors such as the variability of various generation sources, system load growth and the occurrence of contingencies. Simply put, the MCS equipment helps ensure that the generation is within the level that will not strain the distribution system equipment under certain conditions.

The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the impact of thermal loading by, for example, transferring load between feeders. This enables the utility to have more visibility into actual impact and variability of DER on the system and will therefore enable Toronto Hydro to be better equipped to make more accurate planning and operations decisions regarding thermal levels.

3. Monitoring and Control Systems

Since the 2015-2019 rate period, Toronto Hydro has required and facilitated the installation of monitoring and control systems for all new DER connections greater than 50 kW. This has provided the visibility required to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. With the continued implementation of the Program, Toronto Hydro will be able to actively monitor and control DERs in real time to ensure operation within acceptable levels and that the anti-islanding feature of the DERs have properly operated in the event of a distribution system fault.

Figure three depicts the required real-time monitoring and control via utility communication networks and the supervisory control and data acquisition ("SCADA") system.

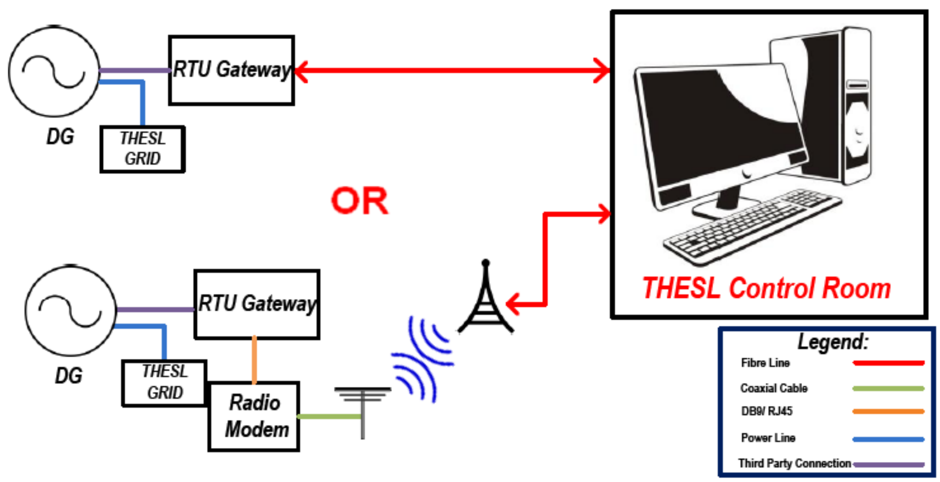


Figure 3: Monitoring and Control Interface to Toronto Hydro SCADA System

Monitoring and control also enables greater real-time visibility into the operating conditions of DER sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A power system controller must account for all DER during a load transfer because the increase in generation connected to the alternate feeder may cause short circuit capacity to be exceeded. The ability to remotely and automatically disconnect all DER sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers' electricity rather than each individual DER site connected to a feeder.

Monitoring and control provide situational awareness into the operating conditions of all DER connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes and to connect additional DER sites to the distribution system. This will have additional long-term value with respect to planning for future DER connections. Currently, Toronto Hydro assesses the potential to connect a DER site to the distribution system based on estimated thermal loading values. This approach assumes that a DER site will continuously generate 100 percent of its rated capacity. This inherently limits the number of DER sites that can be connected to the system, because the conservative estimated value assumes that the thermal loading of the DER site is greater than it likely is at any given time. Monitoring and control will provide Toronto Hydro actual performance data from in-service connections for thermal loading values which will give a more precise view of existing conditions. This, in turn, will feed into DER hosting capacity analyses to automate visualization of estimated available capacity and facilitate cost-effective integration of additional DER on the distribution system. Real-time data will also serve as building blocks for expanding DER connection types through the Flexible Connections pilot concept under the Innovation Fund segment.[8]

Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the IESO. The IESO has developed DER monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DER sites over 5 MW. Because of the volume and capacity of DER sites in Toronto Hydro's service territory (over 304.9 MW in aggregate as of the end of 2022), monitoring and control is required to connect additional DER projects and for grid management. This is also consistent with the requirements and practices of other distributors.

Toronto Hydro's current monitoring and control process allows for the connection of DER sites through a Toronto Hydro communication interface as shown in Figure 4 below along with the standards it adheres to. Figure 5 shows a customer installation, which also adheres to Toronto Hydro standards.

[8] See EB-2023-0195, Exhibit 1B, Tab 04, Schedule 02 for Innovation Fund.

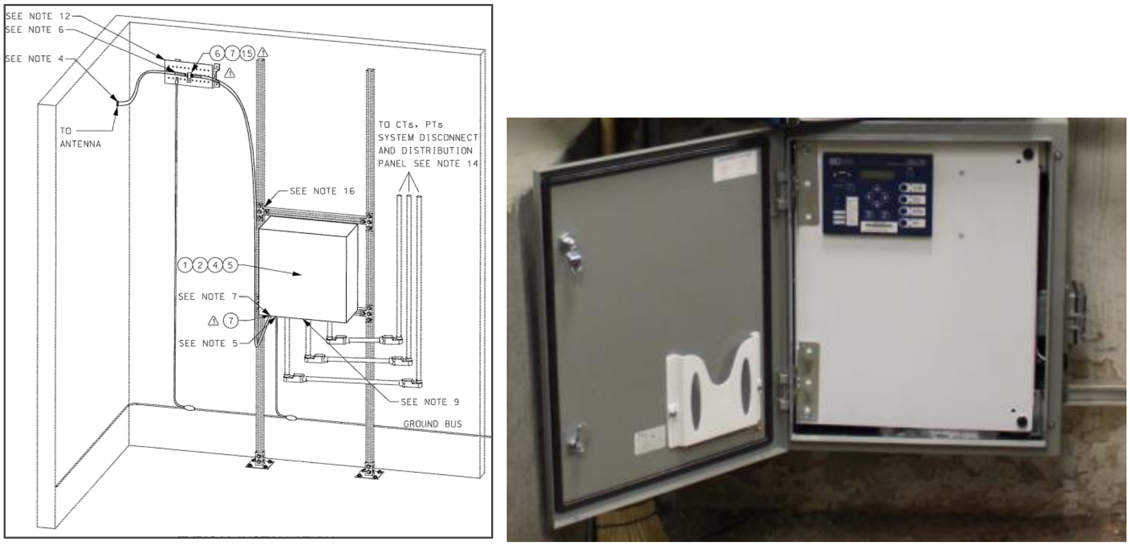


Figure 4: Toronto Hydro Communication Standard for DER Connections (left) and Communication Gateway Installed at Customer DER Site

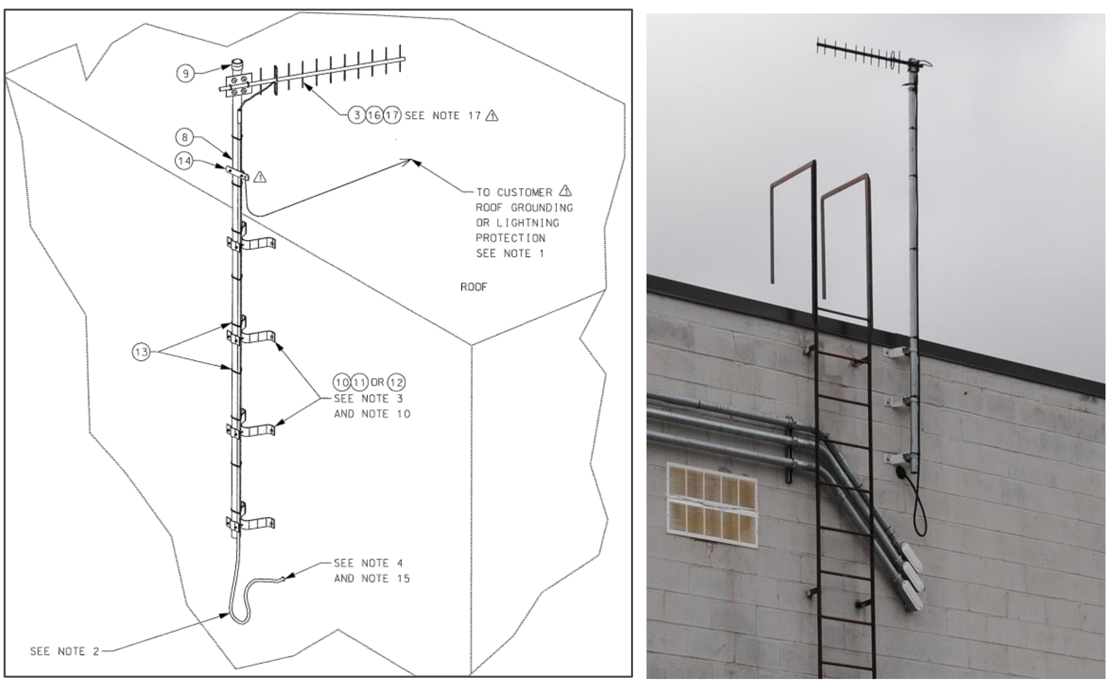


Figure 5: Toronto Hydro Communication Antenna Setup Standard (left) and at a Customer Site (right)

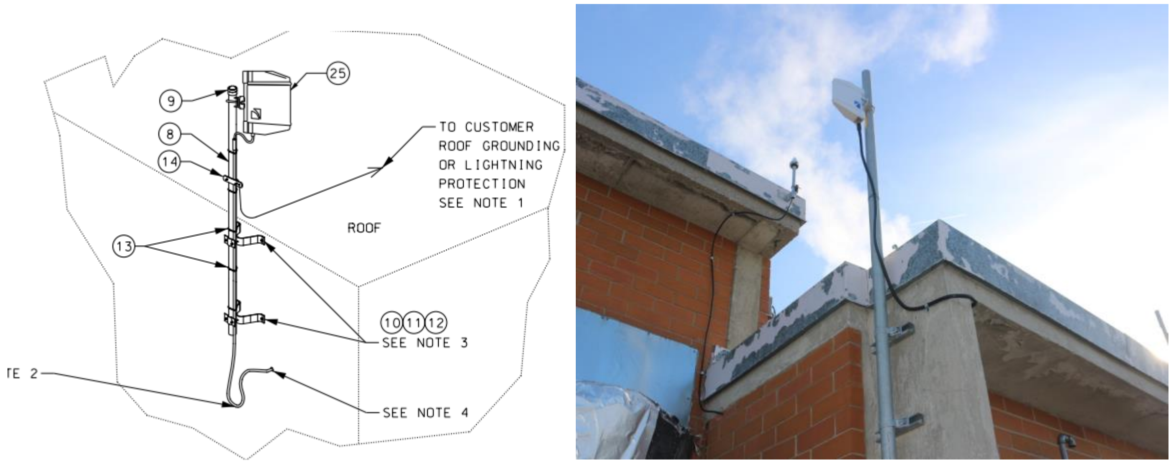


Figure 6: Toronto Hydro Alternative Type Communication Antenna Setup Standard (left) and at a Customer Site (right)

E5.5.4 Expenditure Plan

Table 4: Historical, Bridge & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation Protection, Monitoring, and Control	0.8	0.8	0.1	4.1	5.3	5.9	6.1	6.3	6.5	10.3

E5.5.4.1 2020-2024 Variance

1. Generation Protection

The plan for the 2020-2024 rate period was to install bus-tie reactors at five Hydro One owned and operated transformer substations (Ellesmere TS J bus, Esplanade TS A1A2 bus, Fairbank TS YZ bus, Horner TS BY bus and Sheppard TS BY bus) which Toronto Hydro anticipated would reach short circuit capacity by 2024. As of June 2023, three station busses currently need relief, and of those stations, only Sheppard TS is from the 2020-2024 forecast. These variances can be attributed to both the challenge of accurately predicting where customers will choose to install DERs, as well as a slower rate of DER renewable applications, particularly after the conclusion of the Feed-In-Tariff program and other government incentive driven DER programs (Process and System Upgrade Incentive, etc.).

After consultation with Hydro One, Toronto Hydro ruled-out Sheppard TS for a bus-tie reactor in the 2020-2024 rate period due to technical limitations imposed by the Gas Insulated Switchgear (GIS) bus. This is in addition to a proposed station expansion initiative planned in the near future.

Hydro One and Toronto Hydro carried-out a further study of various bus-tie reactor candidates, which ultimately resulted in the elimination or deferral of a number of potential projects due to technical, physical, or logistical constraints. Richview TS currently stands as the only immediate candidate for a bus-tie reactor installation in the 2020-2024 rate period as its 88-BY bus currently exceeds short circuit capacity limits and the project appears to meet Hydro One's short term feasibility criteria. Toronto Hydro will continue to collaborate with Hydro One to pursue a reactor installation at Richview in the 2020-2024 rate period. The cost associated with the procurement and installation of a bus-tie reactor is roughly estimated at approximately $3 million with actual project cost expected to differ between sites depending on location specific factors such as spacing constraints and electrical configuration, in addition to the current supply chain environment. In the event that the Richview TS station bus-tie reactor installation does not materialize in the current rate period, Toronto Hydro is forecasting it to be implemented early on the next 2025-2029 rate period.

2. Monitoring and Control

For 2020-2024 rate period, the monitoring and control segment was split into three initiatives:

a. MCS Buyback Program;
b. Antenna Installation Program; and
c. New DER Meter and RTU Issuance.

a. MCS Buyback Program

Between 2012 and 2017, there were over 400 renewable generation connections where the customer purchased and installed MCS for their facilities. Sections 3.3.2(g) and 3.3.3 of the DSC provide that utility is responsible for costs incurred related to SCADA system design, construction and connection for renewable energy generation facilities. In compliance with this obligation, Toronto Hydro undertook to reimburse those customers that had directly purchased their MCS. This process involves the negotiation of agreements to purchase the MCS and assign necessary access rights, warranties, etc., in order to facilitate Toronto Hydro's ongoing management of the MCS.

At the start of 2020, there was a total of 135 MCSs that Toronto Hydro needed to buy back from customers at an estimated cost of $135,000. Out of that total number:

- 19 have completed the buyback process;
- 18 are in the purchase agreement sign off stage; and
- the remaining 98 are in audit or deficiency rectification stages, with target completion by the end of 2024.

Note that Covid-19 pandemic related restrictions and limitations temporarily prohibited access to sites, primarily affecting site audit procedures and causing delays to program execution.

b. Antenna Installation Program

In addition to the purchase of 400+ MCS from past customers, Toronto Hydro is installing the radio communication link equipment required to facilitate the two-way communication flow between these DER facilities and the Toronto Hydro Control Centre. Installation began in 2020 and, to date, Toronto Hydro has completed installations at more than 100 sites. The program experienced some delays due to needed updates on the software security and performance settings for these assets. Revisions to installation standards were also required in order to allow new optimal equipment to be installed and connected based on site specific requirements (Antenna type, Modem type, Mounting provision changes, etc.). In addition, the hardware has been updated to LTE technology which is the 3rd iteration from the former GE SD9 and GE Orbit radio modems. Toronto Hydro is mitigating the risk of scope ambiguity going forward by developing a new RFP that provides greater clarity on scope of work requirements. This program is expected to continue past the 2020-2024 rate period and into the 2025-2029 rate period which would cover newer installations as well.

c. New DER Meter and RTU Issuance

The forecast for new M&C equipment for 2020 to 2022 was 31. There were 26 units ordered.

E5.5.4.2 2025-2029 Forecast

Based on current DER forecasts, the Program is projected to cost $35.0 million over the 2025 to 2029 period.

Table 8: Forecast Program Costs ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Generation Protection - Bus Tie Reactor	3.2	3.3	3.4	3.5	7.1
Generation Protection - Monitoring and Control	2.6	2.8	2.9	3.0	3.2
Total	**5.9**	**6.1**	**6.3**	**6.5**	**10.3**

1. Bus-Tie Reactors

Toronto Hydro regularly monitors short circuit capacity trends to identify where constraints may emerge. Based on current information, Toronto Hydro anticipates that eight stations will require relief by the end of 2029. Ellesmere TS can be addressed at no cost by increasing fault limits. Sheppard TS will be addressed through planned expansion work. Bus tie reactors will be required to mitigate short circuit capacity limitations at the remaining six transformer stations at a cost of $20.4 million.

Toronto Hydro plans to begin the design and construction of the first reactor in 2025 and complete installations of six reactor by 2029.

Table 9: Bus Tie Reactor Installations Cost and Installation Schedule ($M)

Station Name	Bus	2025	2026	2027	2028	2029	2025-2029
Richview	88-BY	3.2					
Runnymede	11-JQ		3.3				
Cecil	CE-A1A2			3.4			
Esplanade	X-A1A2				3.5		
Leslie	51-BY					3.5	
Woodbridge	D6-BY					3.6	
Total		**3.2**	**3.3**	**3.4**	**3.5**	**7.1**	**20.4**

Bus-tie reactor installations will occur in accordance with Hydro One feasibility studies. Hydro One will assess station space constraints, station operation disruption, and overall project viability for each site.

2. Monitoring & Control (“MCS”)

Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, Toronto Hydro is required to bear the costs related to communication systems (i.e. MCS) to accommodate the connection of renewable energy generation facilities. For all non-renewable energy generation facilities, the customer is responsible for costs relating to the MCS.

The timing and pacing of the installation of MCSs is driven by customer requests to connect DER to the distribution system. The estimated costs of the installation of MCSs over the 2025 to 2029 period at $14.5 million is based on forecasted DER connections as discussed above in section 5.5.3.1. The equipment and installation costs associated with the integration of a DER site into Toronto Hydro's SCADA system is approximately $25,000 and is based on historical DER MCS installations**.**

E5.5.4.3 Project Prioritization

The Program is driven by customer requests to connect DER to the distribution system and as such, are prioritized on a first come, first served basis. DER customer timelines and deadlines are considered to minimize disruptions and allow for efficiencies, whenever possible.

E5.5.4.4 Cost Management

Toronto Hydro continuously evaluates the selection of bus tie reactor projects to ensure investment is in the appropriate areas. For example, the utility re-evaluates station bus short circuit levels after each new connection application is received for that bus. Connection Impact Assessments ("CIA") are performed for each new DER and are the basis for determining if buses require short circuit relief.

Toronto Hydro is also regularly engaging with Hydro One and is made aware of future station transformer upgrades that could relieve short capacity constraints.

For both segments, variance analyses will also be performed to identify areas for improvement and future cost management.

E5.5.5 Options Analysis

E5.5.5.1 Option 1: Do Nothing

Under this option, Toronto Hydro does not install any bus tie reactors or MCSs. DER connections would continue to occur on parts of the distribution system where they could be accommodated, up until the point where technical limitations are reached. This option will increase the number of DER application rejections and reduce reliability as Toronto Hydro would reach its operational and system design limits which would potentially make the distribution system sensitive to fault conditions with a reduced safety buffer.

Additionally, the inability to have situational awareness and a more precise view into the operating conditions of DER that could impact the grid (through the installation of MCSs), would reduce the utility's capacity to connect additional DER facilities to the distribution system in the future. Failure to connect renewable DER facilities to the Toronto Hydro distribution system would result in non-compliance with the requirements of Toronto Hydro's distribution license, the DSC and *the Electricity Act*, *1998*. As mentioned per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the *Electricity Act, 1998* Toronto Hydro is obligated to connect DER customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. To comply with these obligations, Toronto Hydro evaluated two alternatives (major asset upgrades and the Generation Protection, Monitoring, and Control program) for addressing the system constraints that currently limit the utility's ability to connect the growing demand for DER on the system and safely and reliably manage DER connected to the distribution system.

Without active monitoring of DER facilities, there is an increased risk of unintentional islanding and unintentional back-feed that could have an adverse effect to the grid from DER sources thus reducing reliability on the system. This presents an increased risk to Toronto Hydro linespersons as they will be exposed to back-feed situations. Therefore, Toronto Hydro does not recommend this option.

E5.5.5.2 Option 2 (Selected Option): GPMC Program

The GPMC Program is the preferred alternative, as it is a much more timely and cost-effective solution and would allow for the continued integration, expanded visibility, and monitoring and control of DER connected to the Toronto Hydro distribution system.

In addition, Toronto Hydro expects that the program's solutions will enable prediction of the amount of generation produced by DER connected to the distribution system, a capability that is not currently available to system planners. With performance data gathered through the Generation Protection, Monitoring, and Control program, Toronto Hydro will be able to make better informed decisions on the design and operation of the distribution system. The program would better prepare Toronto Hydro to deliver on commitments to help customers electrify quicker and easier by optimizing use of existing infrastructure.

The program would further advance the Toronto Hydro mandate to facilitate DER connections by directly alleviating technical barriers to connecting DERs, particularly renewable energy sources and energy storage systems, by investing in additional hosting capacity through the installation of bus-tie reactors on Toronto Hydro TSs identified to have short circuit constraints.

The overall cost of this option is $35.0 million over the 2025-2029 rate period.

E5.5.5.3 Option 3: Major Asset Upgrades

As an alternative to the work planned within the Program, Toronto Hydro could address DER requirements via major asset upgrades at transformer stations where short circuit capacity constraints exist. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option. However, with a cost of roughly $19M per switchgear upgrade, not to mention complex coordination of outage and feeder transfers, this would be an uneconomical and impractical approach to enabling incremental DER hosting capacity on the system.

E5.5.6 Continuous Improvement and Productivity

With the implementation of MCS, Toronto Hydro will have access to real time data for all generation sites greater than 50 kW. The information obtained from the MCS and the Energy Monitoring and Control Capabilities can be integrated with distribution system analysis software to produce simulations and reports in a more timely, accurate and efficient manner. This would result in CIA's being completed within the prescribed time at a higher rate. In addition, cellular communication would be the communication medium to be utilized long term using similar architecture of the current radio antenna. This would increase the communication bandwidth for DER telemetry for more precise readings through an increase in communication frequency.

For the bus-tie reactor program, continued emphasis to find the most optimal approach for implementing the reactor installation to increase DER enablement is to be performed. This would be done through fault analysis studies within the on-going coordination initiatives with Hydro One.

MCS assets have the added benefit of integrating with Toronto Hydro's DERMS platform, Energy Centre, to perform real-time coordination and control of DER assets to capitalize on resource management. The RTU embedded within the MCS plays a key role in the integration of other smart grid assets such as smart inverters and microgrids that are detailed in the Non-Wires Alternatives program. Finally, as DER penetration begins to densify on parts of the grid, the communication infrastructure will be crucial to enable aggregation and scalability of DER control from feeder to bus level and beyond.

E5.5.7 Execution Risks & Mitigation

The forthcoming HONI feasibility study for bus-tie reactors could reveal station limitations that deem the reactor installation implausible in certain locations. In these cases, Toronto Hydro will explore other potential short circuit constraint mitigation interventions (e.g. split-bus configuration schemes) before ruling out the possibility of station-level hosting capacity relief in the near-term.

With respect to the Monitoring and Control segment, communication infrastructure (i.e. radio network) may need to be expanded or upgraded to handle a high volume of DER connections. Toronto Hydro is in the process of migrating most of its communication infrastructure to IP based equipment. This would bring about changes to hardware in place and an upgrade program has to be implemented to accommodate such.

Global supply chain shortage would also be another factor that might affect the timeline for execution of both the MCS and bus-tie reactor segments. Engaging vendors early and often to provide the necessary equipment would be key to managing the current delay from manufacturers.

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 207.6	**2025-2029 Cost ($M):** 236.7
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Customer Focus	

The Area Conversions program ("the Program") funds the replacement of legacy 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines, focusing on two unique functionally obsolete 4.16 kV systems known as Rear Lot Construction and Box Construction. These systems serve residential customers in the Horseshoe region, and small commercial and residential customers in the downtown area. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks, and overcome other operational and customer service deficiencies posed by these legacy and aging systems.

This Program is grouped into the following segments and it is a continuation of the renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

- **Rear Lot Conversion:** this segment continues the replacement of functionally obsolete distribution system designs, installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 50 years ago, these assets serving residential customers in the Horseshoe region of Toronto feature below-average reliability outcomes for customers, safety concerns for crews and the public, and other operational and customer service deficiencies. Toronto Hydro is on track to successfully upgrade approximately 683 rear lot customers to front lot 27.6 kV underground services during the 2020-2024 rate period. Toronto Hydro's overall objective for this segment is to prevent rear lot equipment failure risk from worsening, as failures are likely to result in long duration outages and ongoing safety risks to customers and crews from rear lot plant. To this end, Toronto Hydro plans to invest $120.6 million to convert 1,467 customers between 2025-2029, an increase

[1] EB-2018-0165, Exhibit 2B, Section E6.1.

in pacing that reflects an observed increase in the number of assets past useful life on the rear lot system since 2014.

- **Box Construction Conversion:** a continuation of Toronto Hydro's plan to eliminate aging 4.16 kV box construction feeders from the pre-amalgamation City of Toronto. These overhead feeders are located along main streets in the downtown area and serve residential and small commercial customers. Toronto Hydro no longer builds the system to this standard due to safety compliance, reliability, access, equipment, capacity, and procurement issues. The congested box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restrict operations and leads to longer power restoration times when compared to modern overhead standards. During the 2020-2024 rate period, Toronto Hydro expects to convert a total of approximately 3,368 poles from the legacy 4.16 kV to the standard 13.8 kV overhead system, which will remove an estimated 680 box-framed poles from the system. Toronto Hydro is planning to spend $116.1 million to continue conversion of the remaining box construction areas over the 2025-2029 rate period, prioritizing the removal of the last 344 box-framed poles by 2026 to eliminate the various safety and reliability risks these assets present to employees and the public.

Toronto Hydro plans to invest $236.7 million in the program in the 2025-2029 rate period, which is a 14 percent increase over projected 2020-2024 spending (including forecasted inflation). This pace of investment is necessary to mitigate the reliability and the safety risks of these functionally obsolete systems.

E6.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating the risk of long (i.e. 5 to 24+ hours) rear lot outages for an estimated 1,467 residential customers in the worst performing rear lot areas. ○ Improving average outage restoration times for 15,246 residential and small business customers downtown by eliminating the remaining 344 box-framed poles from the system.

Operational Effectiveness - Safety	• Contributes to public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction systems. Specifically: ○ Eliminate safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing remaining box construction assets. ○ Increase the pace of rear lot conversion investment in order to better manage the increasing risk of equipment failure and subsequent safety issues arising from crew access and public exposure to rear lot access.
Customer Focus	• Contributes to Toronto Hydro's customer service performance and customer satisfaction by: ○ Minimizing the need for unplanned crew access to customer property by converting approximately 1,467 residential rear lot customers to front lot service. ○ Improving the speed and cost-efficiency of customer grid access (including for generation and electric vehicles) in high-growth areas of downtown Toronto by converting approximately 1,681 poles from 4.16 kV to 13.6 kV. ○ Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.

E6.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Functional Obsolescence
Secondary Driver(s)	Reliability, Safety, Capacity

This Program addresses distribution assets with legacy design features that result in substandard reliability performance for customers, safety risks for crews and the public, capacity constraints for the system and other undesirable outcomes. For these reasons, Toronto Hydro consider these assets to be functionally obsolete.

The risk of failure increases as these assets age and deteriorate. Hence, Toronto Hydro prioritizes these assets for replacement in order to maintain acceptable reliability outcomes and mitigate exposure to safety risks.

Rebuilding these systems on a like-for-like basis is not a viable option due to the substandard performance, material availability, compatibility issues and safety risks inherent to the existing designs. Furthermore, Toronto Hydro is gradually phasing out its 4.16 kV distribution system in favour of the more efficient 13.8 kV and 27.6 kV systems, which are also better suited to efficiently handle urban growth and development in the City of Toronto.

The following sections provide more detailed information about the drivers of work in the Rear Lot Conversion and Box Construction Conversion segments.

E6.1.3.1 Rear Lot Conversion

The Rear Lot Conversion segment is a continuation of Toronto Hydro's plan to convert and re-supply rear lot customers with underground front lot services. As illustrated in Figure 1 below, the replacement front lot design supplies customers through lateral underground 27.6 kV primary circuits along the roadways with predominantly padmounted transformers. Once customers are connected to the improved configuration, all former rear lot assets are removed to eliminate any existing safety risks.

Figure 1: Legacy Rear Lot Supply vs. Replacement Front Lot Supply.

Rear Lot Conversion is necessary to address reliability and safety risks that are caused or exacerbated by poor accessibility and physical encroachments inherent to the existing rear lot plant location.

1. Rear Lot Reliability Issues

Rear lot plant was generally built in the 1960s and a large portion of these assets are operating beyond their useful lives. As the plant ages, the risk of outages caused by equipment failure increases. Notably, rear lot plant consistently experiences longer duration outages than the average Toronto Hydro feeder (as illustrated in Figure 2 below), primarily due to the difficulty crews face in locating faults and safely accessing and repairing equipment.

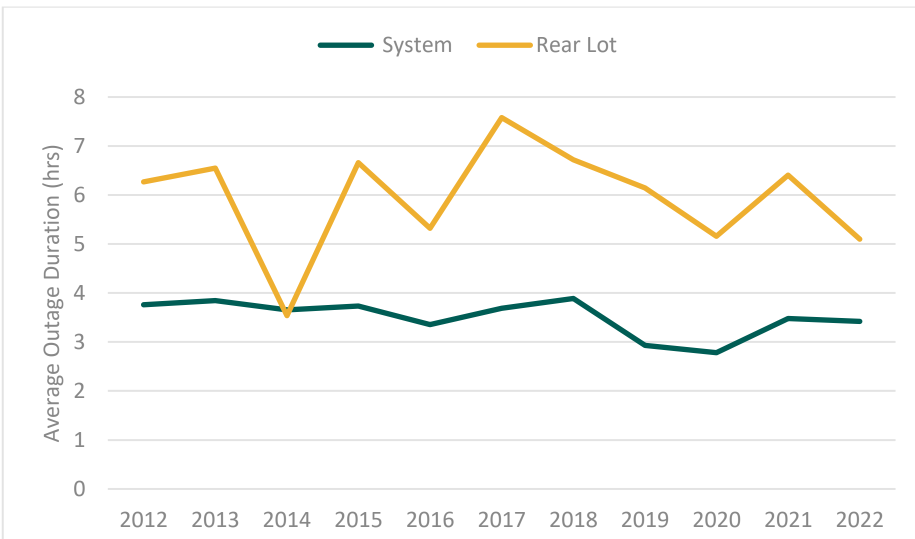


Figure 2: Average Outage Duration Excluding Major Event Days ("MEDs"): Rear Lot vs. All Feeders

On average, over the 2012-2022 period, outages on rear lot feeders were 2.5 hours longer than outages on the system as a whole.

Over the long term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. The average age of the rear lot distribution is already higher than the useful life expectancy of 50 years for most assets. This average age continues to grow rapidly when compared to the rate of conversion, increasing failure risk. It is estimated that by 2029 the average age of the remaining rear lot system will surpass 60 years.

Figure 3 below shows the growing number of customers that will be served by increasingly aged rear lot plant if not addressed.

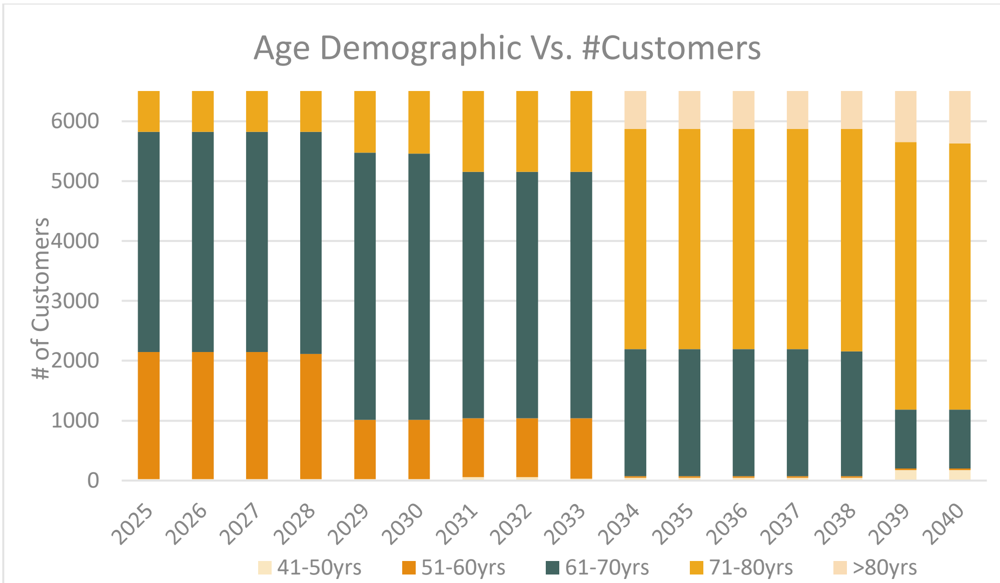


Figure 3: Rear Lot Age Demographic and Number of Customers Supplied

The relatively poor performance of Toronto Hydro's rear lot distribution system is further demonstrated by the number of incidents resulting in loss of service to rear lot customers for at least one day. The location of the infrastructure (i.e. in backyards, often in close proximity to trees, swimming pools and vegetation), and its deteriorating condition make rear lot distribution plant particularly vulnerable during storms and other severe weather events. Furthermore, Toronto Hydro's primary assets in rear lot areas are attached to poles that are predominantly owned by a third-party company, i.e. Bell, making it more difficult for Toronto Hydro to perform maintenance and reactive work to maintain these assets in good condition. Table 4 below contains examples of outages longer than 24 hours in duration that have occurred in rear lot areas. In all cases, accessibility challenges contributed to prolonged outage durations. Many outages on rear lot feeders greatly exceed five hours, as shown in Table 4 below. Toronto Hydro's recent customer engagement demonstrated that reliability, in particular reducing restoration time in extreme weather, is a top priority for residential customers.

Table 4: Long Duration (at least 24hrs) Events on Rear Lot Areas

Date	Station	Feeder	Cause	Duration (hrs)	MED[2] (Y/N)
01-Jun-12	*SCARBOROUGH WEST TS*	NAE5-2M3	WIND EXTREME / ADVERSE WEATHER	25.4	N
19-Jul-13	*BLACKFRIAR MS*	VCF1	WIND EXTREME / ADVERSE WEATHER	44.6	N
19-Dec-13	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	34.5	N
28-Aug-13	*SCARBOROUGH WEST TS*	NAE5-2M3	FREEZING RAIN EXTREME / ADVERSE WEATHER	26.6	N
05-May-17	*ALBION MS*	MGF1	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	26.3	N
04-May-18	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	72.2	Y
05-May-18	*OBERON MS*	UEF3	WIND EXTREME / ADVERSE WEATHER	25.0	N
06-Nov-18	*DELAMERE MS*	PFF3	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	24.4	N
11-Jan-20	*MILL MS*	LFF2	RAIN EXTREME / ADVERSE WEATHER	28.2	N
08-Jul-20	*CHAPMAN MS*	EBF1	RAIN EXTREME / ADVERSE WEATHER	24.0	Y
21-May-22	*WARDEN TS*	NAR43M23	ADVERSE WEATHER / TREE CONTACTS	53.1	Y
21-May-22	*OBERON MS*	UEF2	ADVERSE WEATHER / TREE CONTACTS	49.1	Y
21-May-22	*DALEGROVE MS*	RCF1	ADVERSE WEATHER / TREE CONTACTS	49.1	Y

Rear lot reliability issues are caused by the obsolete design of the plant and the challenging environment in which it operates. As an example, Figure 4 below shows the Jamestown residential rear lot area which Toronto Hydro is upgrading over the 2020-2024 rate period. The primary lateral, shown in red, branches off of the main feeder circuit, enters the neighbourhood in between two

[22] Major Event Day.

houses, and is subsequently routed between the rear of residential properties. The secondary circuit, shown in green, branches off and crosses customer properties to the meter base supplying each residence.

Figure 4: Lateral Circuit Configuration - Jamestown former Rear Lot Neighbourhood

Outage restoration issues stem from the following factors, which are common to rear lot areas such as the one depicted in Figure 4:

- **Manual fault detection:** the vast majority of rear lot feeders operate at 4.16 kV and therefore lack fault detection and isolation technologies such as Supervisory Control and Data Acquisition ("SCADA")-mate switches that are standard in up-to-date distribution systems.
- **Accessibility/Visibility:** in a typical rear lot area, poor access and visibility exacerbate a fault situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration. Limited access can restrict the use of standard equipment such as bucket trucks, drilling machines and other machinery and implements. This means that heavy materials such as poles and transformers must be manually carried or even hoisted over the residence by crane. For overhead feeders, specialized reactive crews are needed to physically climb the poles during repairs. For underground feeders, crews must manually dig trenches to repair direct-buried cables.

- **Obstructions:** spatial constraints like trees and fences may prevent crews from walking on an uninterrupted path along the feeder to locate the fault, forcing them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring service while being mindful of a customer's private property and compliance with electrical safety regulations. For instance, Figure 4 shows the presence of mature trees and swimming pools in the vicinity of Toronto Hydro plant.

- **Non-standard equipment:** the top left area of Figure 4 shows the location of obsolete T-splices (used to split underground distribution circuits). Any outage downstream of a T-splice will affect all customers on the main branch circuit. This is not the case in modern power system design where fuses prevent this undesirable outcome.

The Jamestown area further demonstrates the extent to which reliability can be an issue for rear lots with 23 outages over 2012-2021, the majority of which lasted longer than five hours. This level of service would be considered unacceptable to most customers. Toronto Hydro is rebuilding and upgrading the Jamestown area over the current rate period and reliability has already showed some improvement, with no outages in the areas already converted in 2021 and 2022. Figure 5 below shows the number and duration of outages in the Jamestown area from 2012 to 2022 along with progress made in converting customers (i.e. decrease in rear lot customer count) in the area.

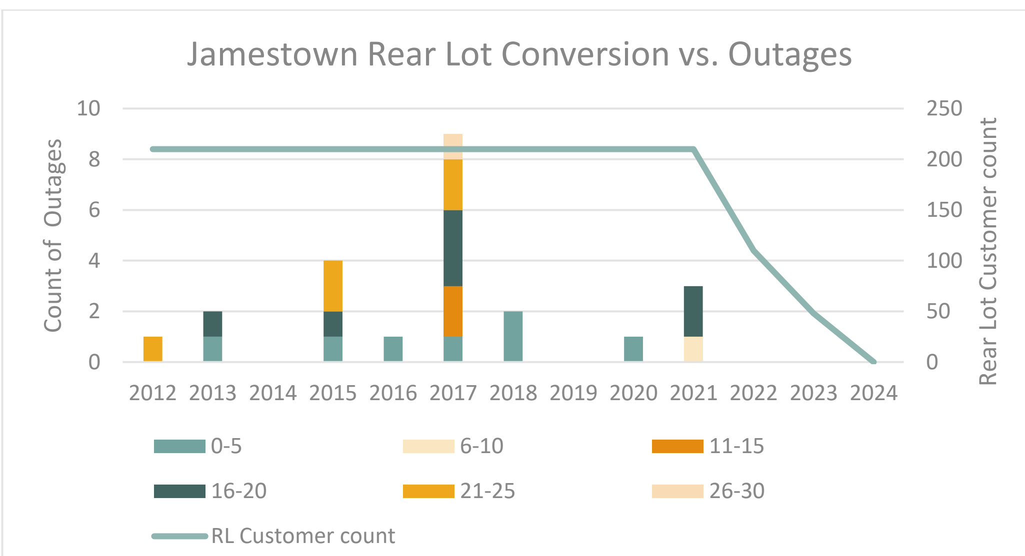


Figure 5: Jamestown Neighbourhood Rear Lot Customer Count and Outage Frequency by Duration

In rear lot areas, 82 percent of the poles have surpassed their useful life and 64 percent of the poles with available asset condition assessment information are showing moderate to material deterioration. Furthermore, 59 percent of the poles in rear lot areas are owned by a third-party company, for which Toronto Hydro has no condition data and it is more difficult for Toronto Hydro to access to perform maintenance and reactive work when required. Table 6 shows the breakdown of Toronto Hydro-owned rear lot poles by asset condition category.

Table 6: ACA Comparison of Toronto Hydro-Owned Rear Lot Poles

Pole Asset Condition Class	% of Assets per Class (2022)
HI1 – Good Condition	28%
HI2 – Minor Deterioration	4%
HI3 – Moderate Deterioration	30%
HI4 – Material Deterioration	27%
HI5 – End of Life	7%
ACA Data Unavailable	3%

Converting an entire rear lot area is a complex and lengthy undertaking that must be carefully sequenced and executed over multiple years. Given the amount and age of the remaining plant, it is necessary for Toronto Hydro to start increasing its pace of proactive Rear Lot Conversion, while prioritizing those areas that are experiencing the worst reliability performance.[3]

Toronto Hydro has ranked feeders according to their reliability performance. The following 'heat map' (Figure 6) shows all rear lot outages from 2012-2022 with dots representing a recorded outage in the rear lot area. The circles overlapping the dots in the chart indicate feeders which have been targeted for conversion in the 2025-2029 rate period. The proposed Rear Lot Conversion plan will continue to address those areas where customers are experiencing the worst service.

[3] Note that Toronto Hydro must ensure that areas that have already been started are fully completed before moving to a new neighborhood, even when those areas are showing temporary reliability improvements due to the partial conversion.

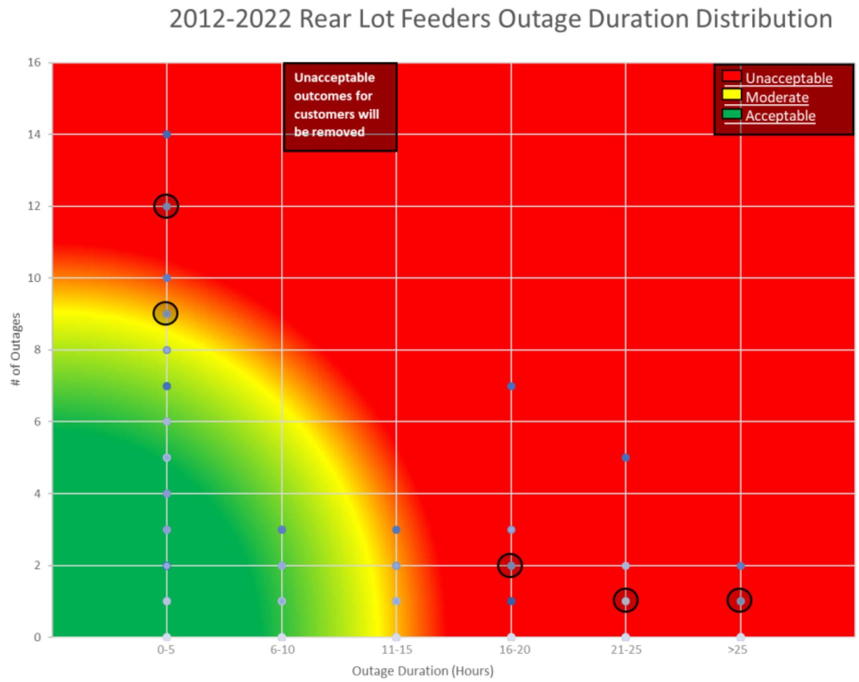


Figure 6: Heat Map of All 2012-2022 Rear Lot Outages

2. Rear Lot Safety Issues

Equally important in the Rear Lot Conversion segment is the need to prudently manage safety risks to crews and the public. These risks are generally caused by the same operational factors and field conditions that contribute to long-duration outages on the rear lot system.

As mentioned above, as assets age and deteriorate, the risk of failure increases along with the likelihood that Toronto Hydro crews will need to access and repair rear lot equipment on a reactive basis. The congested nature and location of rear lot poles means that most cannot be accessed safely using bucket trucks. Workers must instead climb these poles, increasing the risk of potential injury from the additional physical exertion and falling hazard compared to when using a bucket truck, as well as an increased risk of electrical contact due to lack of bucket truck safety mechanisms (insulated aerial boom and bucket liner). Other potential safety risks associated with rear lot plant are:

- tight work spaces and reduced clearances for worker to operate equipment;
- poor visibility at night;
- poor footing in the winter;

- the need to manually transport equipment to poorly accessible job sites;
- the need to climb poles that may be in poor condition due to rot, animal damage, or other environmental factors and may require additional stabilization; and
- obstacles (e.g. fences, sheds, and swimming pools) and clearances between Toronto Hydro's distribution equipment and customer property that do not meet minimum requirements.

An incident demonstrating these safety risks occurred in 2014. Toronto Hydro dispatched a two-member crew following notification of a fallen tree at the rear of a house that had a steep slope covered with snow and ice. One crew member walked up the slope to locate the cable attachment and slipped and injured his right elbow and hip. The following pictures (Figure 7) show similar examples of safety challenges faced by Toronto Hydro crews.

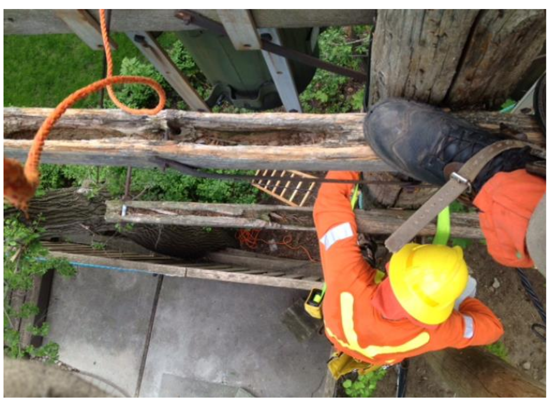


Figure 7a: Field crews replacing failed transformer on pole in poor condition

Figure 7b: Poor condition pole in close proximity to swimming pool

In addition to access issues, mature tree canopy cover (which sometimes requires immediate trimming on site) and poorly constructed landscapes can cause visibility issues in rear lots. Other than contributing to extended outage durations, reduced visibility is a safety concern for crews executing electrical work in locations that do not comply with (e.g. clearances defined in) the Electrical Utilities Safety Rules ("EUSR") rule 129, and applicable standards of the Canadian Standards Association ("CSA"), Toronto Hydro, and the Electrical Safety Authority ("ESA") (e.g. ESA Rule 75-708). The need to manage crew safety risk is one of the primary reasons that Toronto Hydro needs to minimize the aggregate risk of rear lot asset failure.

Public safety is also a key consideration in respect of the Rear Lot Conversion segment. Rear lot assets installed in the 1960s do not adequately account for access needs related to modern growth of neighbourhoods, expansions of homes and live line clearances. Locations have been identified where live wires are in close proximity to customer homes, sheds, fences, and swimming pools. Exposed wires have also been found at riser poles that have been deteriorating or moved over time due to direct contact. Furthermore, when a pole deteriorates or leans, a transformer leaks oil or catches fire, or porcelain insulators break, the safety risk to the public increases when installations are in proximity to those structures. Figures 8 and 9 illustrate some of these issues.

Limits of Approach

1. Rear lot overhead poles, transformers, and live conductors in close proximity to physical properties
2. Obsolete 4.16kV transformers
3. Aged and tilted cross arms and leaning poles
4. Mature vegetation. trees and vines present risk of contact
5. Transformers are typically mounted lower on the poles, in line with windows. If a transformer were to catastrophically fail it may be a hazard to the public or protrude into windows

Figure 8: Energized transformer and pole line close to home and covered in vegetation

Figure 9: Primary conductor and assets near swimming pools

3. Other Rear Lot Issues

The majority of feeders with rear lot areas are operating at 4.16 kV. Toronto Hydro is gradually converting all of these feeders to the standard 27.6 kV and rear lot conversion is an important component of this plan. In many cases, the rear lot area of a feeder must be converted before any other renewal conversion is possible, therefore it essential that the rear lot conversion is paced at a sufficiently rapid rate to enable conversions.

In addition to enabling the introduction of fault detection and isolation technologies like SCADA-mate switches, which are lacking on 4.16 kV feeders, converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs") that 4.16 kV feeders cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

Box Construction Conversion

The Box Construction Conversion segment is a continuation of Toronto Hydro's plan to convert functionally obsolete 4.16 kV feeders with box-framed poles to the latest standard 13.8 kV armless construction. Box construction is a legacy 4.16 kV overhead design. Due to safety, reliability, access, equipment, capacity, and procurement issues, Toronto Hydro no longer builds the system to this standard. As discussed in detail below, safety compliance issues drive the need to eliminate box construction from the system as quickly as practical. Figure 10 below shows the prior, during, and post-construction pictures of two converted box construction locations on Gerrard Street East.

Figure 10: Actual box construction conversion project on Gerrard Street East at two locations. Photographs on the left show 4.16 kV box construction poles prior to conversion. Photographs in the middle are demonstrating the in-construction stage. The completed project is shown in the photographs on the right, where all 4.16 kV box construction has been removed.

4. Box Construction Safety Issues

The industry-wide practice for overhead pole maintenance is to access circuits using bucket trucks. However, the congested nature of obsolete box construction design means that most box construction circuits cannot be accessed safely in this manner. Instead, workers must climb these poles, which increases the safety risks they face. Such risks include potential injury from the additional physical exertion from climbing, an elevated falling hazard when compared to the use of a bucket truck, and an increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on the bucket trucks.

Furthermore, Toronto Hydro crews working in close proximity to box construction lines can have difficulty conforming to the working clearances defined in EUSR Rule 129.[4] The required 15-centimeter air gap between people (or tools) and energized conductors cannot always be achieved. Compliance with these safety rules requires adjustments to normal work operations, such as maneuvering around poles in a bucket truck and closing off road access to multiple poles. This in turn contributes to the lengthy outage restoration times discussed below.

Similar to rear lot lines, some box construction lines also fail to comply with applicable clearance requirements resulting in potential safety risks to the public. Live wires have been found in close proximity to customer homes, windows and balconies. Some buildings are within two to three metres of live lines due to the legacy design parameters of box construction. This issue must be addressed by replacing box construction with updated standard 13.8 kV construction as part of plant renewal. As a visual example, Figure 11 below illustrates some box construction clearance issues.

Limits of Approach

Box Construction poles house conductors with wide cross-arms which cause conductors to be spaced further away from poles and closer to buildings and windows compared to armless construction standards. This photo shows a few of the many issues associated with the obsolete design of box construction:

1. Close proximity of live lines to public and public structures due to the physical properties of the box frame.
2. Aged and tilted cross arms and leaning pole.
3. Transformers are typically mounted lower on the box poles, in line with windows. If transformers were to catastrophically fail, it may cause the windows to break and endanger the public.

Figure 11: Example of Box Construction clearance issues

5. Box Construction Reliability Issues

The existing box construction plant is on average 39 years old and is a poor reliability performer relative to the system as a whole. Despite a steady decrease in the total box construction plant

[4] Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority, Page 34, “online”, https://www.ihsa.ca/PDFs/Products/Id/RB-ELEC.pdf.

remaining over the last 10 years, there has not been a corresponding decrease in the total number of outages on box construction feeders (87 outages over 2013-2017 versus 88 over 2018-2022, excluding MEDs). The top causes of these outages include defective equipment, tree contacts, and adverse weather. Box construction assets are less capable of withstanding strong winds than new 13.8 kV overhead feeders in the downtown area as these assets are aging and deteriorating.

Box construction feeders also tend to require longer restoration times than feeders built to current standards, as shown in Figure 12. The reasons are similar to those that result in longer outages in the rear lot, including: the need for manual fault location; clearance, access and safety issues that slow down operations; and during reactive equipment replacement, the need to integrate newer standard equipment in a unique configuration that is compatible with the existing box construction design.

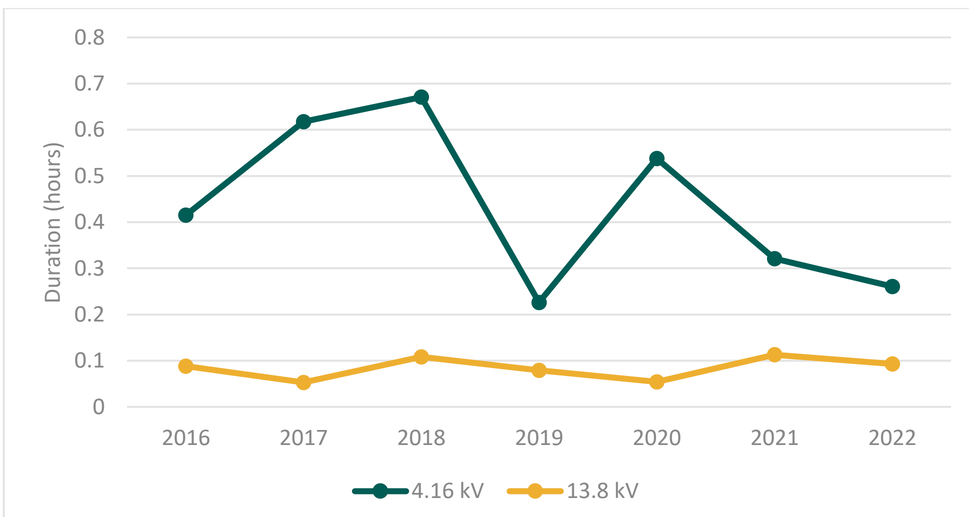


Figure 12: Average Outage Duration per Customer for 4.16 kV (Box Construction) and 13.8 kV Systems Excluding MEDs

Toronto Hydro expects reliability to worsen further as assets continue to deteriorate. Table 7 below shows the percentages of conductors, poles and switches that have already reached or exceeded their useful life. While the proportion of poles at or past useful life is fairly modest at 13 percent (as of 2022), by the end of 2023 another 17 percent will have also reached useful life. Furthermore, when considering the subset of poles that pose the most risk – i.e. those that are box framed – the percent at or past useful life has already reached 60 percent.

Table 7: Percentage of Box Construction Assets at or Past Useful Life

Asset Type	Percentage (%)
Overhead Primary Conductors	56%
Switches	36%
Poles	13%
Secondary Conductors	<1%

Based on asset condition assessment, 9 percent of the wood poles have material deterioration and are in poor condition and this percentage is expected to increase to approximately 35 percent by 2029 without any investments. As with age, when considering box-framed poles on their own, these percentages increase: to 15 percent HI4 or HI5 as of 2022 and 61 percent by 2029 (without investment).

Table 8: Condition Assessment of Box Construction Assets

Asset Class: Wood Poles	% of Assets per Class (2022)	% of Assets per Class (2029)
HI1 – Good Condition	60%	42%
HI2 – Minor Deterioration	5%	18%
HI3 – Moderate Deterioration	26%	4%
HI4 – Material Deterioration	8%	27%
HI5 – End of Life	1%	8%

6. Other Box Construction Issues: Capacity, Efficiency and Grid Modernization

Box construction feeders are part of the 4.16 kV legacy system. Crew members with expertise in legacy assets are needed to trouble shoot and address defective equipment when needed. The inability to acquire legacy assets often force them to repair the system using temporary and non-standard solutions. Workforce retirements are diminishing the pool of employees who are experienced in trouble shooting and repairing box construction feeders, which further underscores the need to eliminate box construction on a firm timeline.

Toronto Hydro is gradually phasing out 4.16 kV in favour of 13.8 kV and 27.6 kV standards. Lower voltage 4.16 kV feeders have significantly lower capacity and are less flexible in accommodating new loads than 13.8 kV feeders. Upgrading feeders to 13.8 kV system will allow Toronto Hydro to more efficiently accommodate new loads, renewable generation connections, and electric vehicle charging stations in high-growth areas of downtown Toronto. Without these upgrades, Toronto Hydro may need to connect new loads using alternative means, such as installing new feeders or extending existing feeders. This requires additional time and resources and may increase the connection costs for customers and developers. As noted above, upgrading feeders to a higher voltage will also reduce line losses and will help prepare the system for activities related to Grid Modernization (such as enhancing restoration capability of the system by adding switching points on the feeders and possibility of introducing self restoration schemes like Fault Location Isolation and Service Restoration ("FLISR")) which cannot be implemented on these legacy assets.

E6.1.4 Expenditure Plan

Table 9 below summarizes the historical, bridge and forecast spending for this Program. After examining program needs and establishing pacing strategies for each segment, Toronto Hydro developed the expenditure plan for the 2025-2029 rate period and applied volume and cost assumptions based on historical accomplishments. The cost estimates were created using the historical average cost per customer (for Rear Lot Conversion) and average cost per pole (for Box Construction Conversion) to extrapolate long-term program costs based on high-level project attributes. The forecast Rear Lot Conversion spending is higher over the 2025-2029 rate period when compared to 2020-2024 levels due to the deterioration of the assets in the rear lot areas due to age, as well as the need to modernize the system to enable growth and electrification. Toronto Hydro plans to eliminate all box-framed poles from the system by 2026 and continue converting the remaining box construction areas. The forecast spending is slightly lower compared to 2020-2024 levels due to the pace of work slowing as the utility gets closer to completing all box construction conversion.

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Rear-Lot Conversion	9.2	9.9	12.8	18.3	11.7	19.8	21.2	23.4	28.5	27.7
Box Construction Conversion	26.5	29.6	21.0	19.6	49.1	44.5	39.9	10.2	10.6	10.9
Total	**35.6**	**39.5**	**33.8**	**37.9**	**60.8**	**64.4**	**61.1**	**33.6**	**39.0**	**38.6**

Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $31.9 million in rear lot conversion projects between 2020 and 2022, resulting in the conversion of 384 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest a total of $61.9 million by the end of 2024 to convert approximately 683 customers over the 2020-2024 rate period, a 71 percent reduction from Toronto Hydro's proposed conversion pace in the 2020-2024 DSP.

In accordance with the OEB Decision and Order on Toronto Hydro's 2020-2024 plan, which reduced the approved Rear Lot budget by $54 million to approximately $60 million, the utility significantly reduced its plan for Rear Lot Conversion and a number of projects (or project phases) and their corresponding customers conversions were deferred as shown in Table 10, below.[5] However, due to external pressures driving up costs and the significant reliability and safety risks associated with rear lot, especially during storm events and as assets continues to age and deteriorate, Toronto Hydro determined that it could not reasonably reduce the level of investment by the full amount prescribed by the OEB in its decision.

Table 10: Status of 2020-2024 DSP Planned Projects

Rear Lot Area	Phases	Number of Customers (2020-2024 DSP[6])	Number of Customers (updated)	Conversion Status
Thorncrest	Phase 9	618	89	Completed
	Phase 10		130	Completed
	Phase 11		114	2024
	Phase 12		147	Deferred
Jamestown	Phase 1	258	100	Completed
	Phase 2		62	Completed
	Phase 3		48	2023
Markland Woods	Phase 6	300	167	Deferred
	Phase 7		118	Deferred
Martin Grove Gardens	Phases 1 to 5	452	137	2024
	Phases 6 to 9		170	Deferred

[5] EB-2018-0165, Decision and Order (December 19, 2019) at page 93.
[6] Note that the number of customers in areas planned for 2020-2024 under the 2020-2024 DSP were high-level estimates and have since been updated based on more detailed information.

Mount Olive	Phases 1 to 3	83	61	Deferred
Kingsview	To be determined	173	156	Deferred
Richview Park	To be determined	263	263	Deferred
Willowridge	Phases 1 to 7	201	201	Deferred

Toronto Hydro plans to invest $120.6 million over the 2025-2029 rate period to convert approximately 1,467 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed (including the risk of prolonged outages, ranging from 5 to more than 24 hours). Figure 13 shows the estimated rate of customers conversion from 2016 to the current estimated completion year of 2052.

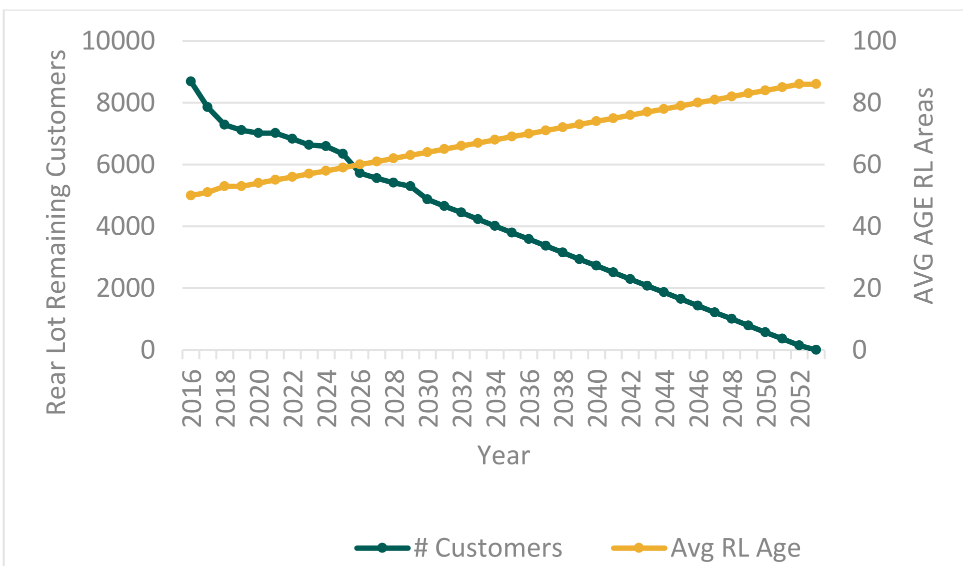


Figure 13: Rate of Conversion of Rear Lot Customers (2015-2029)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used an historical average cost per customer to parametrically estimate 2025-2029 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro continued to use the methodology from the 2020-2024 DSP and examined two rear lot areas, consisting of four projects completed in recent years.

Toronto Hydro applied an average cost of $0.058 million per customer in developing the segment cost forecasts for the 2025-2029 rate period. This is a significant increase over the previous cost per customer estimated in the 2020-2024 DSP due to externally-driven escalations of labour, material, and other (e.g. vehicle) costs over recent years having a particularly high impact on the costs to plan and execute this complex conversion work.

The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Martin Grove Gardens with over 400 customers involved eight phases with multiple customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 100-customer phase rear lot conversion construction project is approximately 24 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first customers will start benefitting from the conversion. For example, if Project Martin Grove Gardens were to be done as single-phase project it would take about 60 months for 400 customers to be fully converted and during that time all those customers would continue to experience a higher risk of outages on the legacy equipment. However, when done in phases, the first 50-70 customers would be converted after only 24 months. This way only a portion of the customers would be at higher risk of outages throughout the full project period. Minimizing the risk of outages minimizes the risk of added costs and long duration outages as crews can spend less time restoring power on legacy equipment.

Rear Lot Conversion projects are prioritized based on asset reliability, equipment condition, and coordination with planned city road work. Generally, the worst performing feeders are targeted for completion first, however rear lot areas where projects have started must be fully completed before moving to a new area despite any changes in reliability performance. To reduce costs, Toronto Hydro also strategically aligns and coordinates rear-lot projects with other conversion projects that share the same feeder. Figure 14 identifies rear lot areas, including those that Toronto Hydro has recently converted and those prioritized for conversion over 2025-2029, with additional details on latter areas in Table 10.

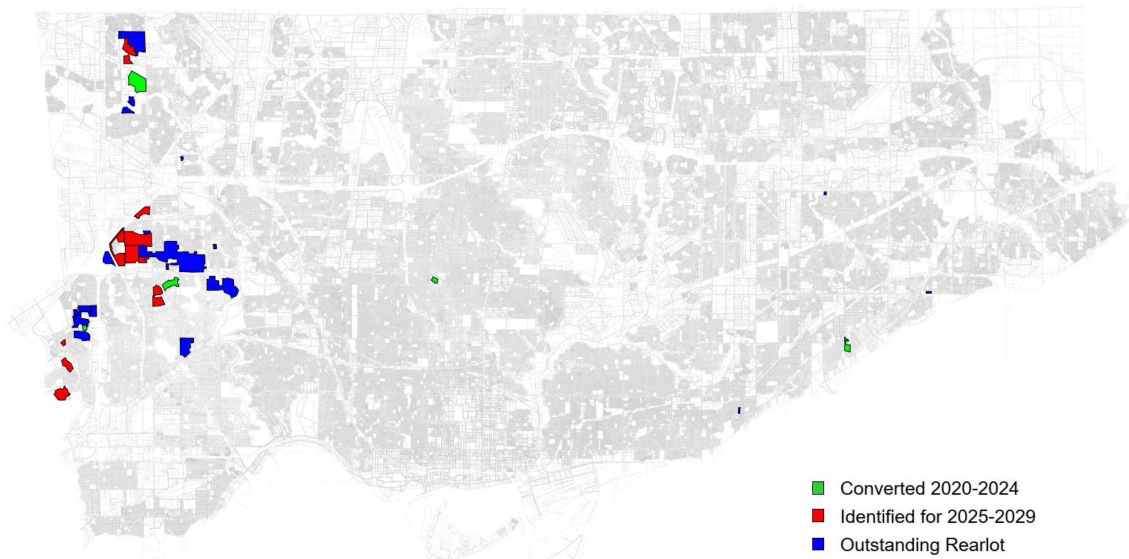


Figure 14: Outstanding Rear Lot Areas to be completed during 2025-2029 and beyond

Table 11: Planned Rear Lot Projects for 2025-2029

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2022)	Number of Outages Greater than 5 Hours (2012-2022)
Thorncrest Phase 12	147	2025	1	0
Markland Woods	285	2025-2026	17	8
Martin Grove Gardens	307	2025-2027	7	2
Willowridge	201	2027-2028	11	3
Mount Olive	61	2027-2028	2	2
Kingsview	156	2028-2029	11	2
Eringate Centennial-West Deane	130	2028-2029	18	2
Richview Park	263	2028-2029	1	0

For the 2025-2029 rate period, Toronto Hydro has planned the conversion of seven rear lot areas, the majority of which the utility deferred from the 2020-2024 rate period as discussed above:

Thorncrest, Markland Woods, Martin Grove Gardens, Kingsview, Willowridge, Mount Olive and Richview Park. One new rear lot area is also planned for conversion towards the end of the rate period, which has been preliminarily identified as Eringate Centennial-West Deane, but may change based on the latest reliability data and any other considerations closer to the time of planning.

Box Construction Conversion Expenditure Plan

Toronto Hydro invested $77.0 million in Box Construction Conversion projects over 2020-2022, removing 444 box frames and converting a total of 1,889 poles to safer, more reliable, and operationally flexible 13.8 kV feeders. The utility plans to invest $68.7 million over 2023-2024 to eliminate approximately 236 additional box frames and convert 1,479 poles. This will leave approximately 344 box frames and an estimated total of 1,681 poles to be addressed in the 2025-2029 period. Toronto Hydro expects to spend about 36 percent ($38.4 million) more than the $107.3 million initially forecast for the 2020-2024 period. The cost variance is driven by changes to the project schedule, including a number of projects that carried over from the 2015-2019 rate period (as shown in Table 11 below), as project phases were deferred or moved up to accommodate internal and external dependencies. Other drivers include externally driven price escalations, coordination and accommodation of third-party initiatives such Metrolinx's Ontario Line and the City of Toronto's CafeTO, and the differences between high level estimates used for the forecasts and the detailed estimates and actual costs following detailed design and construction.

Table 12: Box Construction Projects 2020-2029

	Conversion	Construction Attainment	Projected/ Actual Costs ($M)[7]
Carlaw	2019-2021	Complete	7.3
Dupont	2018-2022	Complete	8.1
Danforth	2018-2024	2024	22.6
Hammersmith	2017-2021	Complete	14.1
Junction	2018-2022	Complete	11.3
Runnymede	2019-2021	Complete	5.0
Wiltshire[8]	2024	2024	0.3
Highlevel	2021-2026	2026	70.5

[7] Excludes inflation and other allocations.
[8] MS Decommissioning.

Sherbourne	2021-2026	2026	21.7
Spadina-Chaplin	2022-2026	2026	37.45
University	2021-2029	2029	25.1
Defoe-Strachan[9]	2017-2026	2026	21.0

Toronto Hydro estimates that $116.1 million will be required over the 2025-2029 rate period to complete full conversion of all except one (Defoe-Strachan, see footnote 8 below) of the remaining box construction areas, which will improve average outage restoration time for 15,246 customers. Other anticipated benefits of this work include (1) addressing safety risks related to EUSR, CSA and ESA compliance issues, (2) improving speed and cost-efficiency of customer grid access in high-growth areas of downtown Toronto, and (3) reduced traffic disruptions due to less frequent repairs and maintenance. Figure 15 below shows the actual and anticipated rate of removing box frames from the system. As discussed further below, Toronto Hydro must complete some conversion work after all the box-framed poles have been removed.

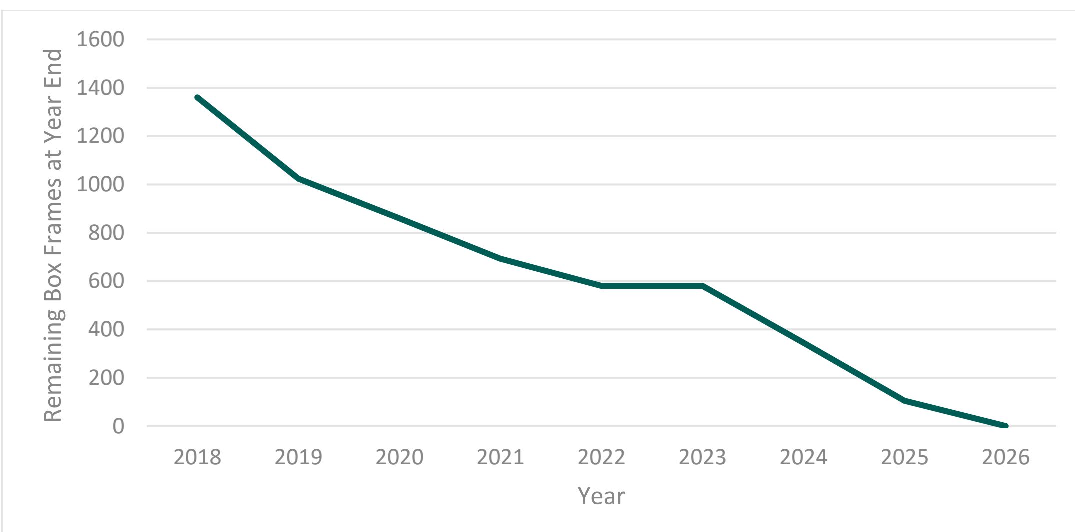


Figure 15: Remaining Box-Framed Poles in the System (2018-2026)

[9] For the Defoe-Strachan area, while all box-framed poles will be removed, full voltage conversion will not be completed until after 2029 due to a number of internal and external dependencies and those costs are not included in the table.

Toronto Hydro examined a number of completed box construction projects to develop an average cost of conversion per pole. This analysis concluded that cost of conversion fluctuates from one project to the next or from one year to other due to area specific characteristics. For example:

- Some areas have lessor number of poles but have coordination and execution challenges while other areas have higher concentration of poles but are relatively easier to construct.
- Some areas have overhead supply directly feeding customers on a quiet side street without trees and underground risers while other areas have box construction assets on a main downtown artery, such as Queen Street, with both primary and secondary distribution and risers going from overhead to underground and vice versa.
- Some areas may have road access issues, moratoriums, work time restrictions, heavy vegetation, or third-party attachments such as TTC street cars that require coordination while other areas may not have these issues.
- Some projects, based on their location and box construction framing density, require different techniques for the safe removal of the legacy equipment.

In order to minimize the cost fluctuations, Toronto Hydro established an average cost of $0.039 million per pole using various projects completed in 2018 to 2022. This average cost of conversion per pole was used to derive the forecast costs for projects for 2025-2026. The increase in this unit cost over the cost per pole in the 2020-2024 DSP reflects inflationary pressures and the fact that the last box construction areas to be completed are the most complex and challenging to design and execute.

Box construction projects planned for the 2025-2029 rate period will convert all remaining box construction on the system, except for part of the Defoe-Strachan area. These phases are interdependent, have to be coordinated with Hydro One, transit authorities including the TTC and Metrolinx, customer connection and third-party development projects, and have to be executed in a particular order. Therefore, Toronto Hydro will continue to manage to the current schedule, prioritizing removal of all remaining box-framed poles by the end of 2026 in alignment with the utility's previously established commitment to eliminate the public and employee safety risks associated with these poles. However, as discussed further in section E6.1.6.2, while it will remove all remaining box-framed poles by 2026, conversion work will be executed in two-phases with only partial voltage conversion at Defoe-Strachan and University completed by 2026. While Toronto Hydro expects to complete full conversion of University by the end of the 2025-2029 rate period, the remaining conversion for Defoe-Strachan cannot be continued until after 2029 due to a number of factors, including conflicts with Metrolinx's Ontario Line work.

E6.1.5 Options Analysis

Options for Rear-Lot Conversion

1. **Option 1: Continue Converting Rear Lot Customers at Current (2020-2024) Pace**

Under this option, Toronto Hydro would maintain the current pace of rear lot conversion over the 2025-2029 rate period. Areas not planned for conversion would continue to pose higher safety risk and be prone to prolonged outages, especially in extreme weather. It would also lead to more reactive replacements of assets, which tend to cost more and do not achieve any of the benefits, such as increased efficiencies and capacity to enable customers to connect new services, related to converting to 27.6 kV. At this pace, it would take until the mid 2050s to convert all remaining rear lot customers, at which point the reliability impact on customers and safety risk would be completely unacceptable given the extreme age and expected deterioration of the remaining assets. Given the current age and condition of these assets, the current pace of conversion is not sustainable and would require a much higher level of investment beyond 2029 to mitigate the increasing risk and deteriorating performance. Especially in light of recent customer feedback that indicates that timely restoration during extreme weather events is a top priority, this option is not recommended.

2. **Option 2 (Selected Option): Convert Rear Lot Customers at Moderately Increased Pace**

Under this option, Toronto Hydro plans to moderately increase its pace of rear lot conversion in the 2025-2029 rate period. This will support mitigation of safety risks and reduce the frequency of prolonged outages, as well as support modernization of the grid through voltage conversion. At this pace, it will still take until after 2050 to convert all rear lot customers and the remaining rear lot areas will continue to pose increasing reliability and safety risks. Toronto Hydro also expects that it will need to increase the pace of investment beyond 2029 to address this escalating risk as these assets age and deteriorate, but not as dramatically as it would need to under Option 1. Toronto Hydro finds this option to be a reasonable balance between residential customers' top two priorities of price and reliability.

3. Option 3: Convert Rear Lot Customers at Accelerated Pace

Under this option, Toronto Hydro would further increase the pace of rear lot conversion over the 2025-2029 rate period. At this pace, Toronto Hydro would eliminate all rear lot plant and its associated risk by the mid 2040s. This would also enable faster progress in converting the system to 27.6 kV and realizing the associated benefits, including lower costs associated with maintaining and renewing municipal stations and improved service levels for customers connecting new services or choosing new technologies such as solar panels. This is the best option for managing rear lot risk and standardizing the grid, but the additional cost cannot be justified at this time given Toronto Hydro's other investment priorities and the need to limit rate increases.

Options for Box Construction Conversion

1. Option 1: Full Voltage Conversion and Box-Framed Pole Removal beyond 2026

In this scenario, Toronto Hydro would delay the removal of the last box-framed poles from the system beyond 2026, when it could be incorporated into full voltage conversion projects. Station constraints (see section E6.1.6.2 for more detail) and other considerations have resulted in certain areas being unfeasible to fully convert to 13.8 kV by the end of 2026 as previously planned. Delaying the removal of some box-framed poles beyond 2026 presents unacceptably high safety risks to Toronto Hydro employees. The utility is committed to meeting its previously established 2026 target for box-framed pole removal. Therefore, this option is not recommended.

2. Option 2 (Selected Option): Removal of Remaining Box-Framed Poles by 2026

This option will eliminate the significant safety risks associated with box construction assets for crews and the public by the end of 2026. It will also remove capacity constraints, renew aging and deteriorating assets, improve reliability for customers, and enable the retirement of station assets that will be otherwise costly to renew or maintain. This option involves removing all box-framed poles by the established deadline of 2026, but full voltage conversion and station decommissioning for two areas will be completed later due to station constraints.

This option is recommended as it enables the fastest possible elimination of the safety risks associated with box-framed poles, while providing short and long-term benefits to customers and the utility.

E6.1.6 Execution Risks & Mitigation

Rear-Lot Conversion

Timely third-party project coordination: One program risk is the potential for a minimum five-year moratorium on new road work in areas where Toronto Hydro intends to do rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work (i.e. through utility coordination council meetings). In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer Engagement: Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot conversion, which by nature are relatively intrusive and involve construction on multiple sides of each customer property. To determine asset locations that best align to customer preferences, Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customers to voice their concerns and to work with the designer and constructor. In most cases, community meetings are held to proactively introduce residents to the project plans and educate them on construction implementation. City Ward councillors are informed of the project and often are invited to community meetings and pre-construction meetings to assist with constituent inquiries. Written letters are sent in advance to customers' homes to inform them of the project, new equipment installations and line of sight to new equipment as per applicable municipal notice requirements.

Conversion coordination: The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e. during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections require careful staging of conversion jobs over several years.

Box Construction Conversion

Station Constraints: In order to do the voltage conversion work, affected 13.8 kV stations need to have spare cell positions and 4 wire capability. If these are lacking in an area, Toronto Hydro works with stakeholders to implement them where needed. However, this can take time and may be dependent on external factors, such as Hydro One work. For two of the remaining box construction areas, Defoe-Strachan and University, this is an issue that Toronto Hydro cannot address in time to complete full box construction conversion of these areas by 2026 as was previously intended. Therefore, Toronto Hydro's strategy in these areas is to perform box-framed pole removals with and without voltage conversion, i.e. partial conversion of these areas. Where feasible, Toronto Hydro will rebuild portions of the feeders to remove box-framed poles while the system remains energized at 4.16 kV, with a provision to add 13.8 kV lines on the renewed poles in the future, once constraints are resolved. For the remaining box-framed poles that cannot be removed without conversion, the utility will transfer load to open up a few cell positions and enable some voltage conversion.[10]

Project Interdependencies: Projects in this segment have highly interdependent phases that have to be executed in a particular order. Delays in any particular phase cascade to the later phases of the project. In order to remove box frames within the established timeline, Toronto Hydro regularly reviews the execution plan to identify and resolve any emerging issues.

Customer Coordination: For the majority of the commercial customers serviced on 4.16 kV system, there is underground equipment, risers, and terminations connected to the pole. Transferring a riser and termination requires an outage to the customer to conduct work safely. Coordinating power interruptions and access with customers could delay projects. Toronto Hydro is mitigating this risk through proactive and early customer engagement.

Construction Coordination: Many of the remaining box construction assets are within high pedestrian and vehicle traffic areas which also include TTC bus or streetcar routes (see example shown in Figure 16). In this regard, mitigation involves proactive coordination and engagement with the City to create a traffic plan, especially at major intersections. Most pole installations require a single lane to be occupied by trucks and equipment and as such, inadequate coordination would jeopardize project completion in a timely manner.

[10] Note that some of this load transfer relies on energization of Copeland Station (Phase 2).

Figure 16: Area with High Pedestrian and Vehicle Traffic, including TTC Routes.

Third-Party Assets: Third-party assets attached to the utility poles, such as Rogers, Bell, and City assets, can interfere with full conversion and pole removal work. Toronto Hydro will engage owners of these assets as soon as possible to coordinate and plan their transfer to avoid delays.

E6.2 Underground System Renewal – Horseshoe

E6.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 359.8	**2025-2029 Cost ($M):** 475.7
Segments: Underground System Renewal Horseshoe	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment	

The Underground System Renewal – Horseshoe program ("the Program") manages failure risk on major underground distribution assets serving customers in the Horseshoe area of Toronto. The Program invests in proactive asset renewal and focuses on maintaining the reliability, safety, and environmental risk levels of major underground distribution assets. This program is a continuation of the activities described in the Underground System Renewal – Horseshoe program in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

The Program addresses three major underground asset classes: cables, transformers, and switches. These assets deteriorate over time due to usage, aging, and exposure to harsh environments which increases the risk of failure. Legacy asset design issues exacerbate the probability of failure for certain asset types targeted by this program.

Outages caused by asset failure on the underground system take approximately 34 percent longer to restore than outages on the overhead system, resulting in lengthy interruptions that may last up to 24 hours or longer. The failure characteristics of legacy underground cables are such that customers can experience multiple cable-related outages in a short period, leading to potentially significant declines in customer satisfaction in affected neighborhoods.

The program consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are typically addressed through rebuild projects. Voltage conversion is another

[1] EB-2018-0165, Exhibit 2B, Section E6.2

important consideration for rebuilds. For example, Toronto Hydro has a population of legacy 4.16 kV feeders in the Horseshoe that it is gradually converting to modernized 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4.16 kV is no longer an accepted system standard, when 4.16 kV asset condition and performance within an area deteriorate, Toronto Hydro will generally rebuild the area to current standards rather than replace individual assets on a like-for-like basis.

The Program's investments in the three major underground asset classes are summarized as follows:

- **Cables**: Cables are the greatest contributor to outages caused by defective equipment on Toronto Hydro's system in the Horseshoe, resulting on average in 146,000 customer hours of interruption per year. Through prioritized neighbourhood rebuild projects focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro previously had success reducing the number of customer interruptions due to cable failure, from over 200,000 per year in 2013 to approximately 105,000 in 2019. However, more recently Toronto Hydro shifted focus away from rebuild projects addressing direct-buried cables in order to address the urgent environmental risk associated with PCBs. As a result, customer interruptions (and other reliability indicators) have started trending back up, reaching 199,000 in 2022. As of 2022, there are 666 circuit-kilometres of direct-buried cable in the underground system, of which 286 circuit-kilometres are direct-buried cable in dirt, and 380 circuit-kilometres are direct-buried cable in PVC ducts. While direct-buried XLPE cable (not in duct) was previously considered the highest failure risk, direct-buried cable in PVC ducts is now also a priority as it can get clogged with dirt and get sheared due to the movement of earth, making it difficult to replace the cable inside the PVC duct. Toronto Hydro expects the entire direct-buried cable population to be a significant source of failure risk and driver of reliability outcomes as the cables continue to age over the 2025-2029 period. Over half of this cable has reached or passed its useful life as of 2022. Toronto Hydro plans to replace an estimated 340 circuit-kilometers of underground cable, including 182 circuit-kilometres of direct-buried cable over the 2025-2029 period to maintain current average reliability performance on the underground system and to help sustain improvements in the number of feeders experiencing seven or more interruptions per year ("FESI-7").

- **Transformers:** Underground transformers are typically exposed to harsh environmental conditions, and defective transformers cause approximately 17,700 hours of customer interruption per year and contribute to 21 percent of failures on the underground system. As of 2022, 26 percent of underground transformers have reached or surpassed useful life, and over 600 units have at least material deterioration. Without proactive investment, Toronto Hydro expects the number of units past useful life to increase to 39 percent (over 10,000 units) and the number with at least material deterioration to increase to 2,400 by 2029. Toronto Hydro replaces aging and deteriorated underground transformers proactively as part of rebuild projects, and will continue to do so in the 2025-2029 period. Over the 2020-2024 period, Toronto Hydro has shifted towards doing more spot replacements to support the utility's objective of reducing the number of potentially high-consequence PCB leaks. In 2025, Toronto Hydro plans to continue the replacement of the remaining underground transformers that are known to contain, or are at risk of containing, PCB-contaminated oil. Over 2026-2029, the utility will shift back towards a more rebuild-focused approach, using spot replacements for only the worst condition transformers not addressed through rebuilds. Overall, the utility plans to replace an estimated 2,478 underground transformers during the 2025-2029 period through a combination of area rebuilds and spot replacement, with the objective of maintaining average system reliability, eliminating the risk of PCB leaks, and supporting long-term risk management of the underground transformer population.
- **Switches**: Underground switches are continuously exposed to harsh environmental conditions, and their failure typically leads to prolonged outages, ranging from approximately two to 35 hours, affecting an average of 1,350 customers at a time. On average, switches have contributed to approximately 20,000 hours of customer interruption annually. Failure of these assets can also pose employee and public safety risks due to the potential for arc flashing, a risk that is higher with Toronto Hydro's remaining population of legacy air-insulated switches. The number of air-insulated padmounted switches in end-of-serviceable life condition ("HI5") is anticipated to rise from 29 in 2022 to 104 by 2029, which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field.[2] During the 2025-2029 period, the utility plans to proactively replace an estimated 116 underground padmounted switches in conjunction with area rebuild projects,

[2] Over 90 percent of the failed switches that the utility analyzed in the last five years failed prior to reaching their expected useful life of 40 years, with the highest rate of failure occurring in the 10-14 years range.)

prioritizing higher-risk air-insulated switches operating beyond useful life and/or exhibiting material degradation.

Toronto Hydro plans to invest $475.7 million in the Underground System Renewal program in 2025-2029, which is a 32 percent increase over projected 2020-2024 spending in this Program (including forecasted inflation). This pace of investment is necessary to maintain current average reliability on the underground system, sustain improvements in the number of feeders experiencing seven or more interruptions a year, and prevent asset-related risk on the underground system from increasing in an unsustainable manner over the long-term.

E6.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC"), by upgrading 106 circuit kilometres of low capacity 4.16 kV or 13.8 kV distribution lines to higher voltage capacity of 27.6 kV distribution lines.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, Direct Buried Cable replacement measure) by ○ Replacing approximately 340 circuit-kilometers of underground cable that includes 182 circuit-kilometres of direct buried underground cable that poses elevated risks to reliability; and ○ Replacing assets at and beyond useful life or showing signs of at least material deterioration (i.e. HI4 and HI5) at the end of 2029[3]

[3] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

Environment	• Contributes to improving Toronto Hydro's performance in relation to the Spills of Oil Containing PCBs measure, and reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing the remaining underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2025, pursuant to PCB regulations (PCB Regulations[4] made under the Canadian Environmental Protection Act, 1999[5], the Environmental Protection Act[6] and the City of Toronto's Sewer Use By-Law[7])

E6.2.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure Risk
Secondary Driver(s)	Environmental Risk, Safety, Reliability, Capacity Constraints/Growth

The Underground System Renewal – Horseshoe program focuses on replacing three types of assets: cables, transformers, and switches. These assets are the primary components of the underground distribution system, and will typically be replaced in accordance with current standards, generally on a like-for-like basis, unless part of a voltage conversion project.

The proposed renewal is driven by the risk and impacts of asset failures on system reliability, the environment, and public and employee safety. These risks are primarily due to two factors. The first is accelerated degradation of asset condition due to exposure to external elements, such as dirt, salt, dust, moisture, and humidity. This contributes to a loss of integrity of the physical asset, which can in turn lead to failure. Secondly, assets that are at or approaching their end of useful life have a higher probability of failure.

Table 4 provides the useful life of the underground assets in the Horseshoe area. Asset failures may lead to: (1) reliability risks, which can cause outages and directly impact customers; (2) environmental risks, such as oil spills (which may contain PCBs) that harm the environment; and (3) safety risks, resulting from arcing and catastrophic failures.

[4] SOR/2008-273
[5] SC 1999, c. 33
[6] RSO 1990, c. E.19
[7] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

Table 4: Useful Life of Underground Assets by Type in the Horseshoe

Type		Useful Life (Years)
Direct Buried Cable	*Installed in PVC Duct*	40
	Not Installed in PVC Duct	20
Cable in Concrete Encased Duct		50
Transformers	*Submersible*	30
	Padmounted	
	Building Vault	
Switches	*Padmounted*	40
	Vault	

The number of outages due to underground defective equipment has been a major contributor to overall system outages over the last 10 years, constituting almost 56 percent as shown in Figure 1. Historical investments in the Program have driven some reduction in outages due to underground defective equipment, reaching a low in 2019, but this has since started trending up again. A similar pattern has emerged for Customers Interrupted ("CI") and Customers Hours Interrupted ("CHI"), which indicate the impact of these outages on customers, as shown in Figures 2 and 3. This recent deterioration in underground defective equipment driven reliability is largely driven by cable-related outages and is at least partly attributed to Toronto Hydro's prioritization of the removal of PCB at-risk underground transformers during the current rate period. This has shifted work in the Program towards more spot replacements of transformers based on PCB-risk and away from direct-buried cable renewal. As the remaining PCB at-risk transformers are removed from the system, Toronto Hydro plans to shift back to a more balanced distribution of work that will better mitigate reliability risk.

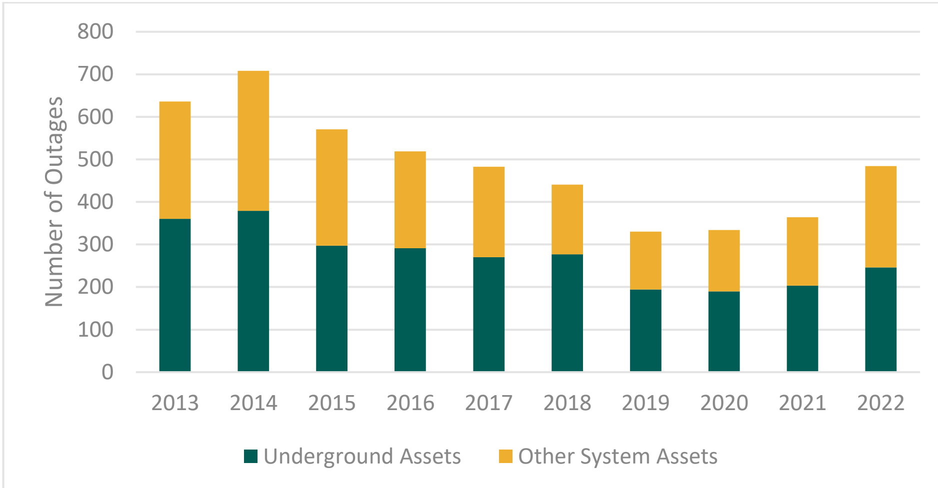


Figure 1: Ten-year Trend of Underground System Contribution to Overall System Outages

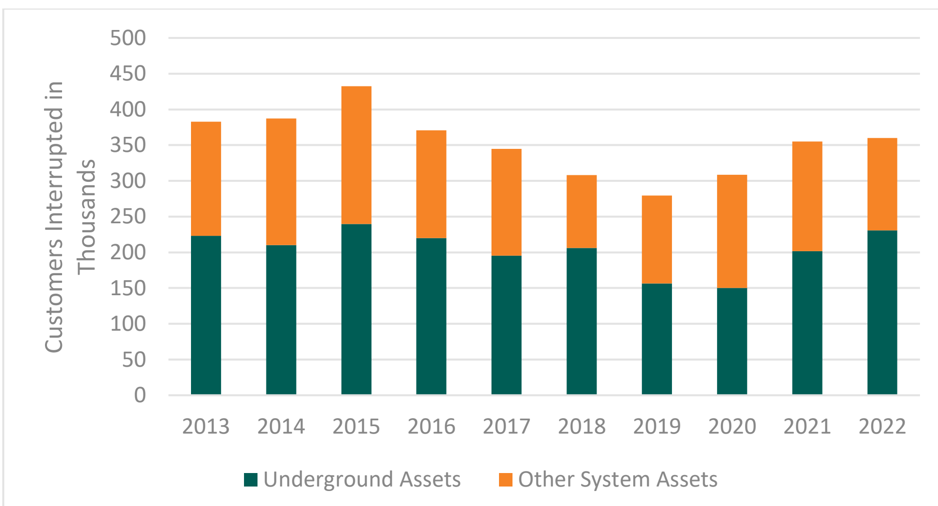


Figure 2: Ten-year Trend of Underground System Contribution to Overall System Customers Interrupted ("CI")

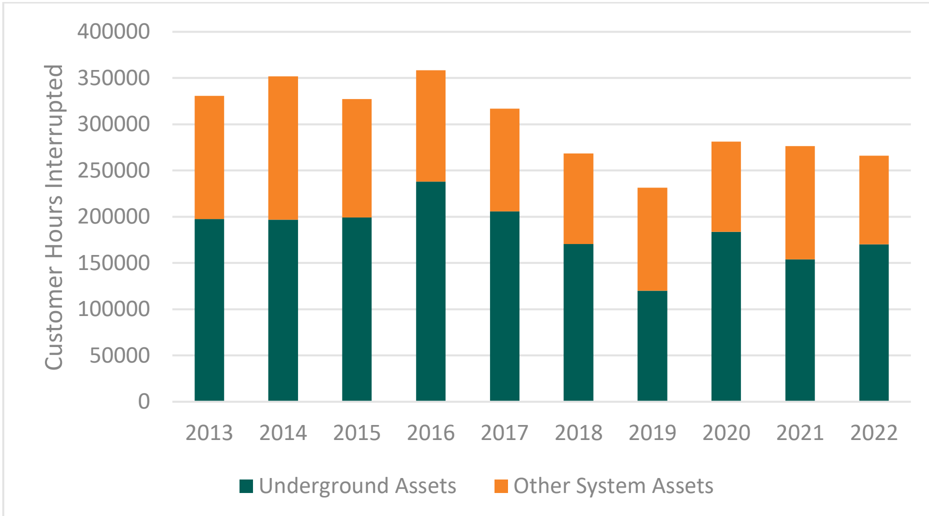


Figure 3: Ten-year Trend of Underground System Contribution to Overall System Customer Hours Interrupted (CHI)

While historical investments improved underground reliability in the Horseshoe area over 2015-2019, performance has started to backslide more recently and Toronto Hydro must increase the pace of renewal to prevent further deterioration. A significant number of assets (e.g. cables) are already past their useful life as of 2022 and the population continues to age. This increases the risk of failure, requiring Toronto Hydro to reactively replace faulted underground equipment. In general, underground assets are more difficult to replace compared to those in the overhead system, mainly because they are installed below-grade and not readily visible or accessible for fault locating.

When an underground fault occurs, controllers first check SCADA devices to determine which section of the feeder is affected. Next, crews look at fault indicators installed on various points on a feeder to locate the component that has faulted, a process that can take hours. Fault locating of direct buried cable is particularly challenging, as crews first need to perform tests to identify the general location of a fault, then dig up that location to confirm and pinpoint the actual cable fault. In some cases, crews need to dig multiple pits to identify the exact location before they can make repairs, prolonging the outage and inconveniencing customers. Operational outages to repair these assets can also expand the outage to surrounding areas thus affecting more customers.

Additionally, the nature of the work leads to significant unplanned disruptions and inconveniences for the neighbourhood and community as a whole, and often requires last minute coordination with third parties under emergency situations and tight timelines. For underground assets, this is particularly difficult where customers own the assets (such as vaults), as coordination can delay the repair work and extend the outage. In contrast, proactive replacement allows Toronto Hydro to coordinate work with third parties well ahead of the scheduled repair work.

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 340 circuit-kilometers of underground cable, 2,478 underground transformers, and 116 switches over the 2025-2029 period.

Outages on assets at 4.16 kV and 13.8 kV voltages continue to be responsible for a significant number of outages despite more than a decade of work converting to 27.6 kV. In 2013, areas fed by 4.16 kV and 13.8 kV feeders contributed to over 35 percent of the total outages on the underground system and this has increased to over 43 percent on average over the last five years (2018-2022). Any targeted underground areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. These are legacy assets which cannot be easily replaced and their configurations do not allow for expansion and provide limited options for system restoration during contingency. The overhead portion of these feeders are addressed by the Overhead Renewal program as well as the Area Conversions program.[8] Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of DERs that 4kV cannot accommodate; and,
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert both the overhead portion and the underground portion of 29 of these feeders by 2029. At this pacing Toronto Hydro expects it could complete the underground voltage conversion portion of the entire system by 2055-2060.

[8] Exhibit 2B, Section E6.5; Exhibit 2B, Section E6.1.

E6.2.3.1 Replacement of Underground Cable

Toronto Hydro plans to replace underground cable that is past its useful life along with high-risk direct-buried cable that causes poor reliability in the Horseshoe area.

Generally, two types of cables exist in the Horseshoe underground distribution system: (i) XLPE; and (ii) tree-retardant cross-linked polyethylene (“TRXLPE”). These can be installed in three ways: (i) direct buried; (ii) in direct-buried Polyvinyl Chloride (“PVC”) ducts; or (iii) in concrete-encased ducts. The majority of direct-buried XLPE cables in Toronto Hydro’s system were installed before 1990 and were fabricated using manufacturing processes that are now considered inferior. These assets were installed using a legacy type of construction methodology where cables were laid directly in underground trenches without a protective barrier.

These cables are susceptible to outages due to direct exposure to environmental conditions. Moisture is the most destructive element that affects direct-buried XLPE cable. Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called “water treeing”. Over time, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity). This causes the cable to internally short circuit and fail.[9] Additionally, direct-buried XLPE cables in PVC ducts can get clogged with dirt and get sheared by the movement of earth or other external factors, making it difficult to replace the cable inside the PVC duct as shown in Figure 4 below.

Based on Toronto Hydro’s experience with direct buried cables, following an initial failure (which is typically a sign of deteriorated insulation and electrical and thermal stresses along the entire segment), subsequent failures in the cable segment occur with greater frequency. Additionally, voltage stress applied to the cable during the fault locating process further degrades the cable insulation.

[9] Exhibit 2B, Section D2 for more details

Figure 4: Clogged PVC Ducts

Underground cable system failures that include underground cables, terminations, and other cable accessories account for approximately 73 percent of the defective equipment-related outages in the underground Horseshoe system as shown in Figure 5 below. The ten-year reliability impact of the underground cable system discussed in this Program is shown in Figures 6 to 8. After reaching a low (improved reliability performance) in 2019, the reliability impact of underground cable systems has started to trend higher again and proactive replacement of underground cable systems is required from 2025-2029.

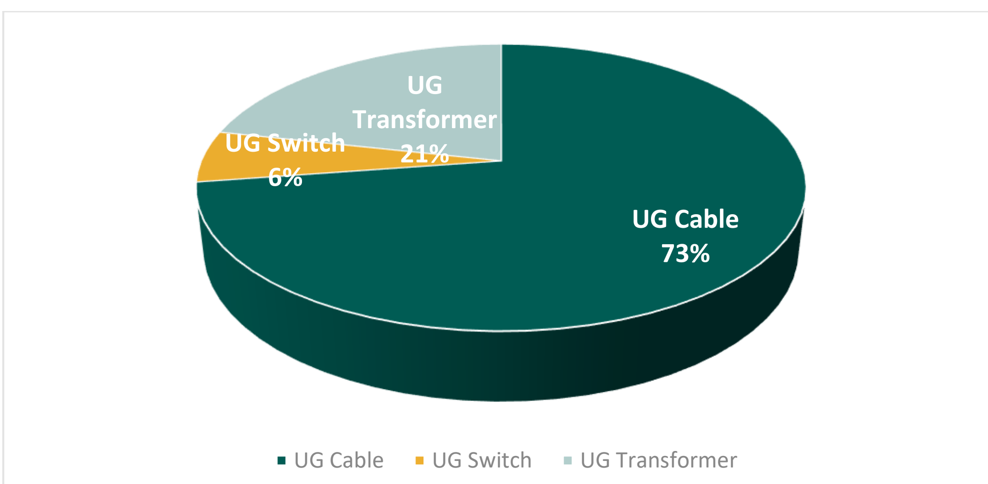


Figure 5: Underground ("UG") Equipment Failures in Underground Horseshoe System by Asset Type from 2013 to 2022

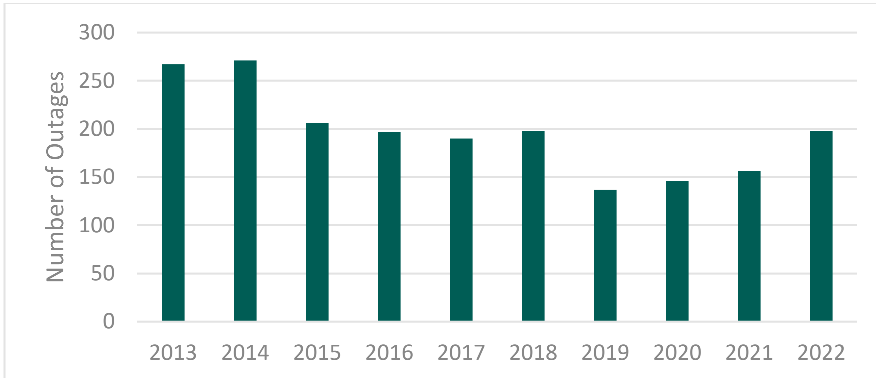


Figure 6: Ten-Year Trend of Outages due to Underground Cable Failure

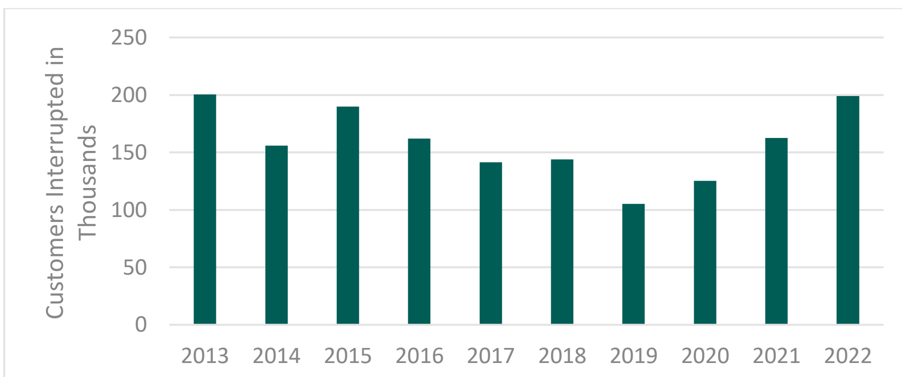


Figure 7: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures

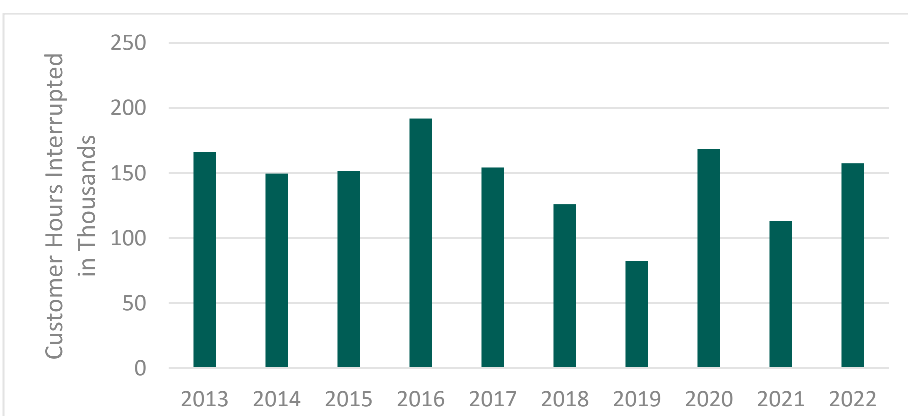


Figure 8: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

In addition to the type of cable, age is an important indicator of failure risk. Figures 9 depicts the age distribution of direct-buried XLPE cable (not in duct) in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 73 percent of this direct-buried XLPE cable in Toronto Hydro’s distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 20 years). Without replacement, the length of this type of cable at or beyond useful life will reach 215 circuit-kilometres by 2029, which represents 75 percent of the direct-buried XLPE cable in Toronto Hydro’s underground Horseshoe distribution system. This increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure and further erode the reliability improvements made prior to 2020.

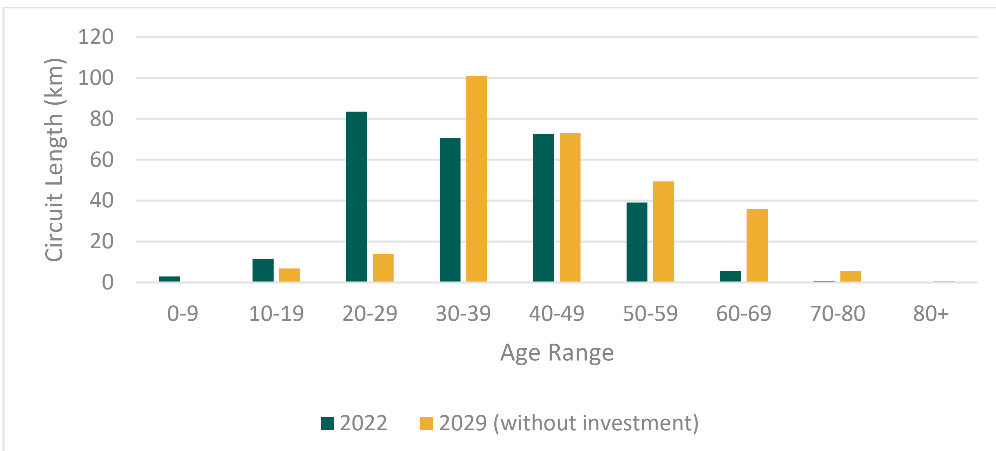


Figure 9: Age Demographics of Direct-Buried (“DB”) Cable XLPE in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Figure 10 depicts the age distribution of the direct-buried cable in duct in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 35 percent of this direct-buried cable in duct in Toronto Hydro’s distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 40 years). Without replacement, the length of this cable at or beyond useful life will reach 144 circuit-kilometres by 2029, which represents 38 percent of the direct-buried cable in duct in Toronto Hydro’s underground Horseshoe distribution system. As with the direct-buried XLPE cable (not in duct), the increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure

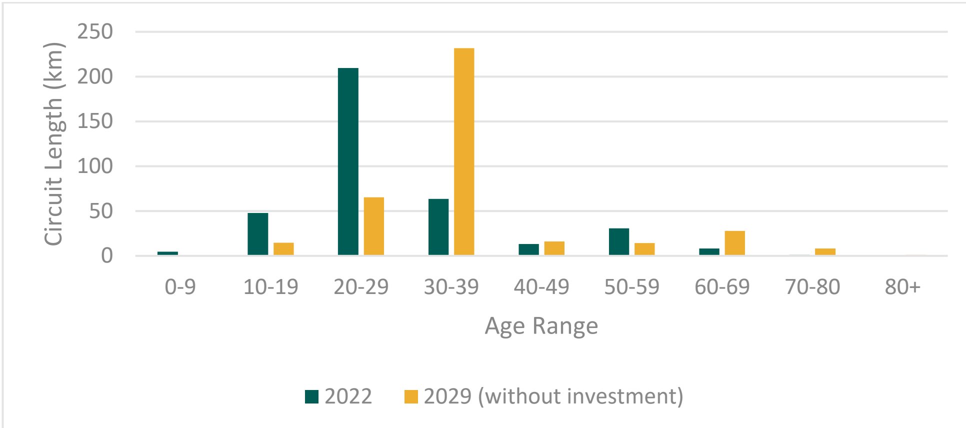


Figure 10: Age Demographics of Direct-Buried Cable in-Duct in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Although cables installed in concrete-encased ducts are more protected from environmental changes and mechanical damage, failures can still be caused by age and a variety of factors such as insulation breakdown, moisture ingress, and overload. Figure 11 shows the current age distribution of cable inside concrete-encased ducts in the Horseshoe in 2022 and in 2029 without investment. As of 2022, 9 percent of the cable inside concrete-encased ducts in the Horseshoe is at or beyond its useful life of 50 years. Without replacement, the length of cable at or beyond useful life will reach 357 circuit-kilometres by 2029, which represents 12 percent of cable installed in concrete-encased ducts. Proactive replacement of these cables is required to reduce failures and help maintain reliability on the underground system.

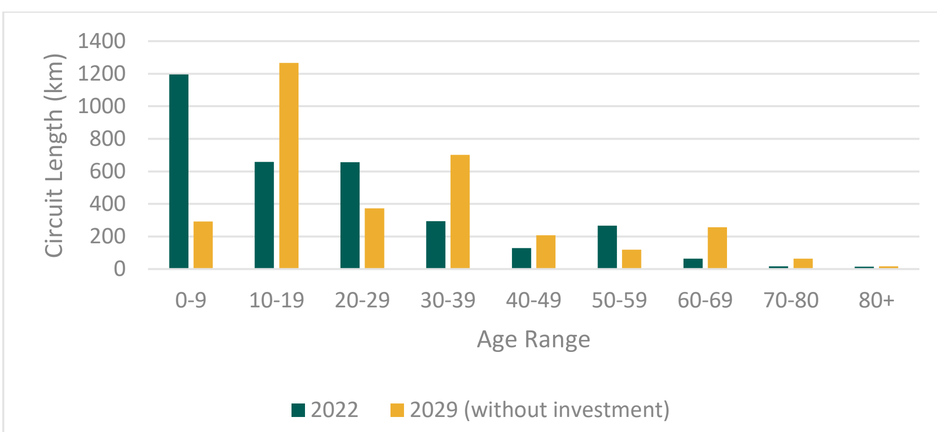


Figure 11: Age Demographic of Cable in in Concrete-Encased Ducts as of 2022 and by 2029 (without Investment)

Toronto Hydro is taking proactive measures to address the risks associated with deteriorating and legacy direct-buried cable as well as concrete-encased cable past useful life. The utility plans to replace approximately 340 circuit kilometres of underground cable, including 182 circuit kilometres of direct-buried cable (out of total of 666 circuit kilometres), through underground rebuild projects over the 2025-2029 period.

To improve reliability and public safety, Toronto Hydro plans to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil or in PVC duct. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety. Additionally, installing cables in concrete-encased ducts significantly reduces the time needed to replace faulty cables, as new cables can be pulled into existing ducts. This approach will improve reliability and reduce outage times.

Toronto Hydro has also started performing cable diagnostic testing[10] on prioritized underground cables to provide a more accurate assessment of the condition of underground cables, splices, joints and terminations using a combination of very low frequency tan-delta ("VLF TD") and/or partial discharge testing on Horseshoe feeders/segments. This is executed in two phases:

- Phase 1 consists of visual inspections, Online Partial Discharge, and infrared ("IR") scanning of the end point locations to identify any immediate deficiencies.
- Phase 2 consists of monitored withstand cable testing (Time Domain Reflectometer or "TDR", as well as either online/offline Partial Discharge and/or VLF TD testing). In some cases, Phase 2 testing can only be performed after corrective actions from Phase 1 have been addressed.

In the past, factors such as age, historical failures, and number of joints were used to determine appropriate replacement strategies for these cables. However, under this program, select subdivisions in the Horseshoe area are chosen for testing to assist with making capital investment decisions using more condition-based data and to address areas with poor reliability. During 2021 and 2022, this program provided a more accurate assessment of the condition of underground cables, splices, joints, and terminations. As shown in Figure 12, this initiative has identified a number of deficiencies and generated corrective work that has helped the utility to mitigate cable failures and associated reliability risks. As this program continues to mature, the diagnostic data available on

[10] See Exhibit 4, Tab 2, Schedule 2.

cables will continue to grow and will help Toronto Hydro predict cables at risk of degradation and identify problematic locations in the system with a higher degree of accuracy. While Toronto Hydro is currently ramping up this program, it will require a significant amount of time to test the entire underground cable population and the utility will continue to lack this additional information for a large amount of cable.

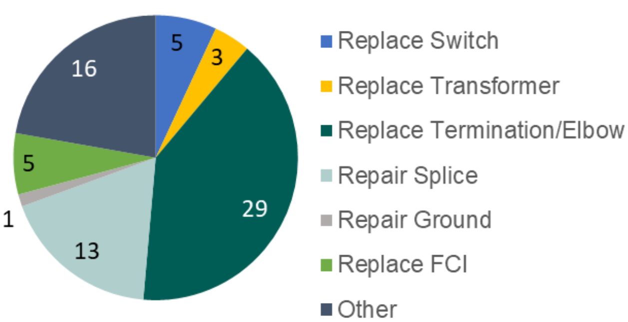


Figure 12: Type and Number of Deficiencies Identified from Cable Testing Program 2021-2022

E6.2.3.2 Replacement of Underground Transformers

Toronto Hydro plans to replace transformers that are at risk of failing and pose an environmental risk due to potential oil leaks (potentially containing PCBs). There are currently 25,753 underground transformers in Toronto Hydro's Horseshoe distribution system, with three main types: (i) submersible; (ii) padmount; and (iii) building vault. Toronto Hydro owns approximately 8,847 submersible transformers, 6,345 padmount transformers, and 10,561 vault transformers, all of which are vulnerable to deterioration from exposure to harsh environmental conditions.

Submersible transformers are located below-grade in small structures such as vaults and can be found on public road allowances or private properties. Padmounted transformers are metal-clad enclosures with lockable cabinet doors that are located on top of concrete pads, often within road allowances or on private properties. Vault transformers, on the other hand, are located above ground level in civil structures and, like padmounted transformers, supply residential areas or commercial buildings.

The harsh environmental conditions to which transformers are exposed cause them to deteriorate over time. Moisture, particularly groundwater and moisture ingress, is the most destructive element leading to the corrosion of the enclosures. Over time, precipitation and humidity can cause tank perforation, which can result in oil leakage into the environment. The oil leakage reduces transformer oil levels, causing the paper insulation to dry up. When this is combined with the heat generated due to loading, arcing can occur with the potential for a catastrophic failure of the unit. These failures pose significant risks to the public and Toronto Hydro employees as these transformers are located next to sidewalks and on private properties. A summary of the 10-year reliability of the underground transformers is shown in Figures 13 to 15. There has been an overall downward trend in the number of system outages since 2017, which is also reflected in the customer impact reliability indicators, Customers Interrupted and Customer Hours Interrupted. This improvement can be attributed to the recent focus on proactive replacement of underground transformers containing, or at risk of containing PCBs. However, in 2022 there was some worsening of transformer-related reliability and, without continuous investment in this segment, Toronto Hydro expects the reliability improvements made in recent years to be eroded and eventually reversed.

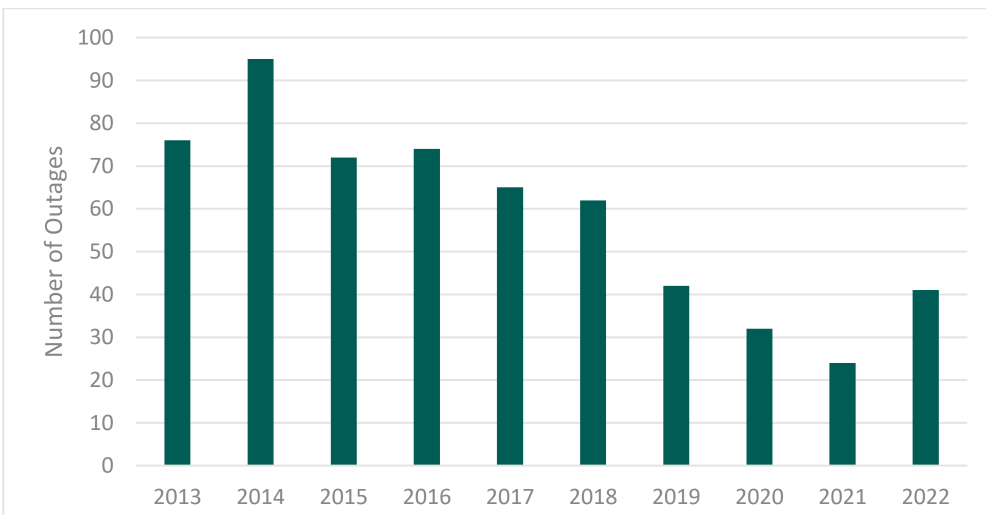


Figure 13: Ten-Year trend of Outages Due to Underground Transformer Failures

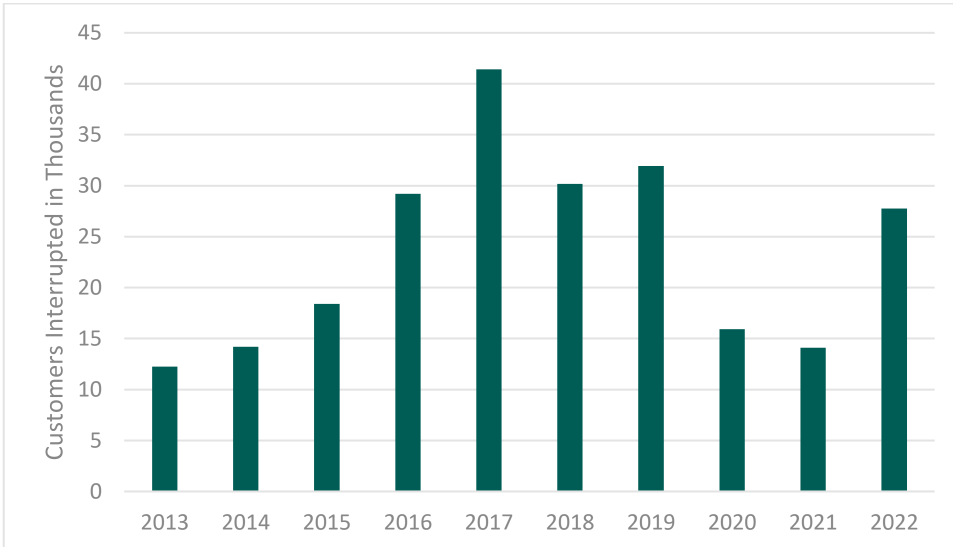


Figure 14: Ten-Year Trend of Total Customers Interrupted (CI) Due to Underground Transformer Failures

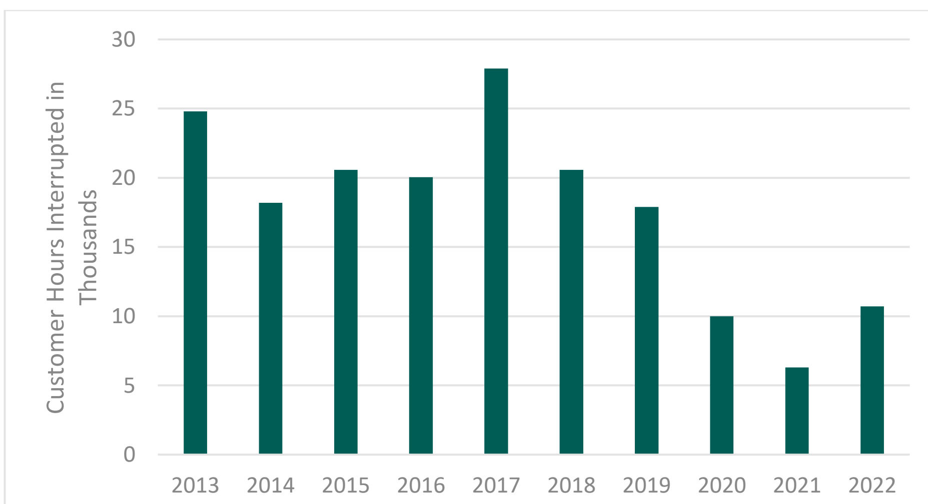


Figure 15: Ten-Year Trend of Customer Hours Interrupted (CHI) Due to Underground Transformer Failures

A number of underground transformer failures in the Horseshoe area have also resulted in oil leaks into the environment. The risk of oil leaks is particularly high for older transformers, which may contain oil with PCBs. Releasing oil, including oil containing PCBs into the environment may breach the City of Toronto's Sewer Use By-Law[11], Ontario's *Environmental Protection Act*[12] and, the federal *Canadian Environmental Protection Act*, *1999*[13] potentially resulting in penalties, or orders to perform remediation work or to otherwise address non-compliance. Toronto Hydro has been targeting underground transformers at risk of containing PCBs, which are all also past their useful life, and estimates that there will be 492 underground transformers that contain or are at-risk of containing PCBs remaining at the end of the current rate period. Toronto Hydro intends to replace all of these units by the end of 2025.

Figure 16 illustrates the number of externally-reported oil spill incidents from 2018 to 2022. The increase in reported spills from 2018-2020 is attributed to a modification of the inspection process in 2018 to improve the reporting of transformers with the potential to leak (i.e. are heavily corroded). During this time, the frequency of inspections for select submersible transformers was also increased based on the condition of the transformer from its most recent inspection. The additional inspections for the more at-risk transformers enabled Toronto Hydro to identify more oil spills, resulting in a higher number of incidents reported in accordance with Ontario's *Environmental Protection Act*[14] at Part X (Spills), and the City of Toronto's Sewer Bylaw, Chapter 681.[15]

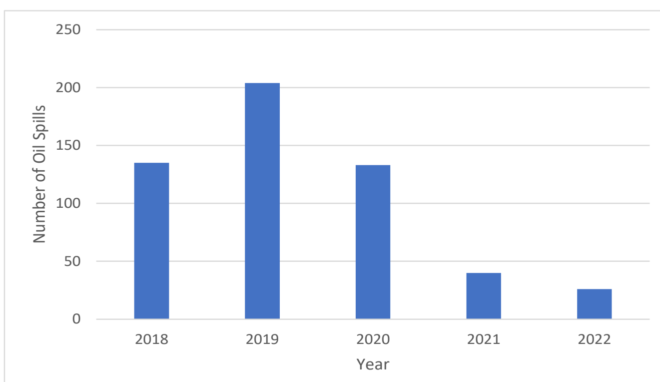
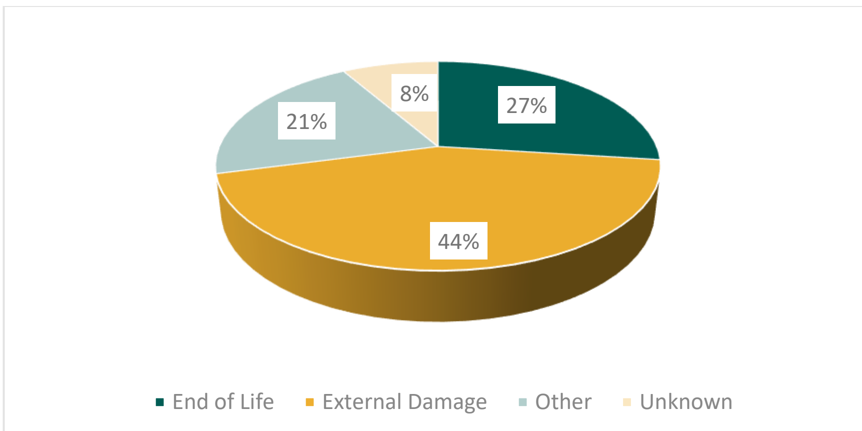


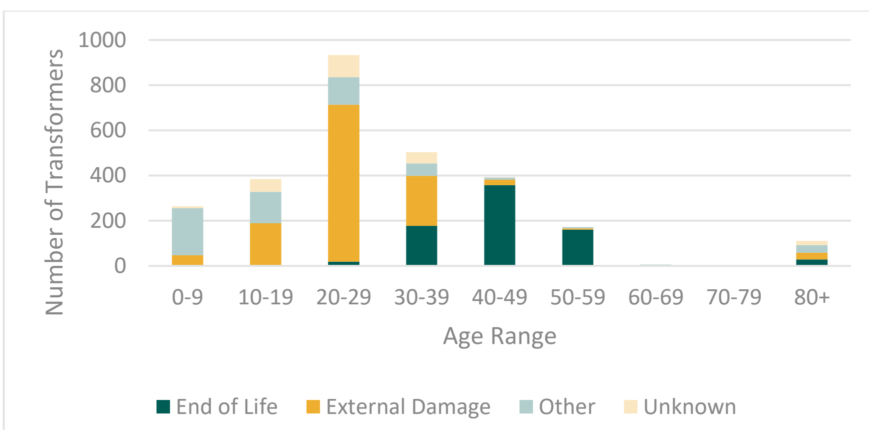
Figure 16: Number of Externally-Reported Oil Spills on Underground Transformers in Underground Horseshoe System

[11] City of Toronto, by-law No 681, Sewers, (May 15, 2023).
[12] RSO 1990, c. E.19
[13] SC 1999, c. 33
[14] RSO 1990, c. E.19
[15] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

1 Toronto Hydro investigated 2,555 underground transformer failures that occurred between 2013
2 and 2022. The results of this analysis (see Figure 17 and Figure 18) show that 27 percent of the failed
3 underground transformers failed at or beyond useful life and the number of failed units increases
4 with transformer age. Therefore, if not proactively replaced, transformers on Toronto Hydro's
5 distribution system, which are at or beyond their useful life of 30 years, are at an increased risk of
6 failing.



7 **Figure 17: Root Cause Distribution for Failed Underground Transformers from 2013 to 2022[16]**



8 **Figure 18: Age at the Time of Failure for Failed Underground Transformers from 2013 to 2022**

[16] Others, represent 44 percent which include failures such as supplier quality, lighting strikes, corrosion, overvoltage, contamination etc.

Figure 19 shows the current age distribution of underground transformers in the Horseshoe area in 2022 compared to what it will be in 2029 without investment. As of 2022, 26 percent of underground transformers in the Horseshoe area (i.e. 6,727 units) were at or beyond useful life (i.e. 30 years for padmount, submersible, and vault transformers). Without any replacement, the percentage of transformers at or beyond their useful life will reach 39 percent (i.e. 10,001 units) by 2029. An increase in the number of transformers at or beyond their useful life will increase the risk of units failing, and will erode and eventually reverse the improvements in reliability made in recent years. Additionally, without sufficient replacement, Toronto Hydro will face a backlog of transformers requiring replacement beyond 2029.

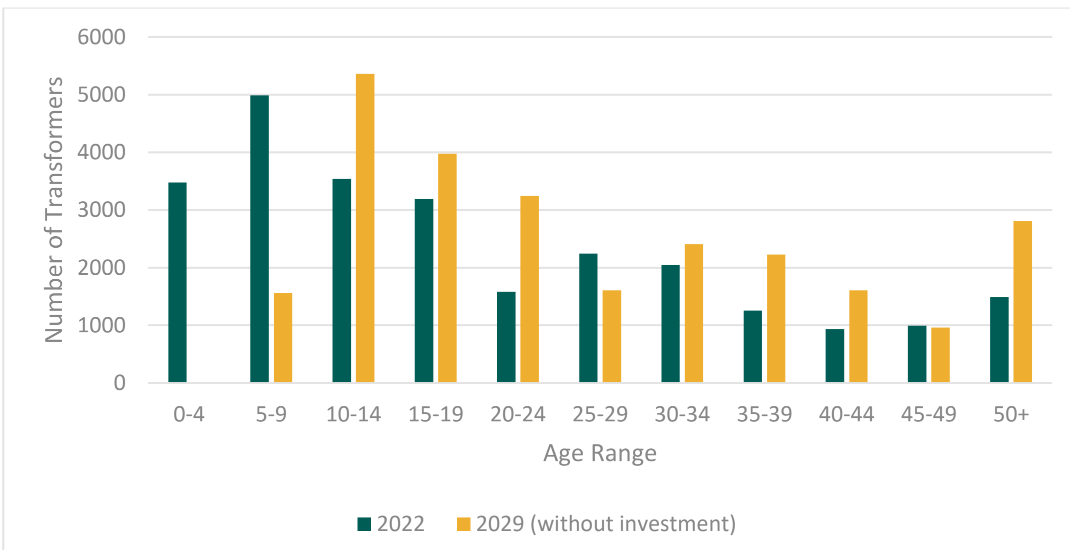


Figure 19: Age Distribution of All Transformers in Underground Horseshoe System as of 2022 and 2029 Without Investment

While age can be a good indicator of a population's current and future failure risk, asset condition assessment provides a more accurate indication of asset failure risk and the need to replace underground transformers (where PCBs are not a factor). As of the end of 2022, 639 transformers exhibit at least material deterioration (i.e. HI4 and HI5) as shown in **Error! Reference source not found.**Table 5 below. Without any capital investment, this number is expected to reach 2,400 by the end of 2029. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue to deteriorate. The asset condition profiles of the transformers as of 2022 and in 2029 (forecasted) without investment are shown in Table 5 and Figure 20.

Table 5: Asset Condition Assessment for Underground Transformers in Underground Horseshoe System in 2022 and 2029 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total	Total
	2022	2029	2022	2029	2022	2029	2022	2029
HI1 – New or Good Condition	4521	3920	7666	6939	6108	4625	18295	15484
HI2 – Minor Deterioration	1009	469	548	585	3618	1533	5175	2587
HI3 – Moderate Deterioration	476	804	130	534	494	3400	1100	4738
HI4 – Material Deterioration	215	561	120	178	225	506	560	1245
HI5 – End-of-Serviceable Life	22	489	46	274	11	392	79	1155
Grand Total	**6243**	**6243**	**8510**	**8510**	**10456**	**10456**	**25209**	**25209**

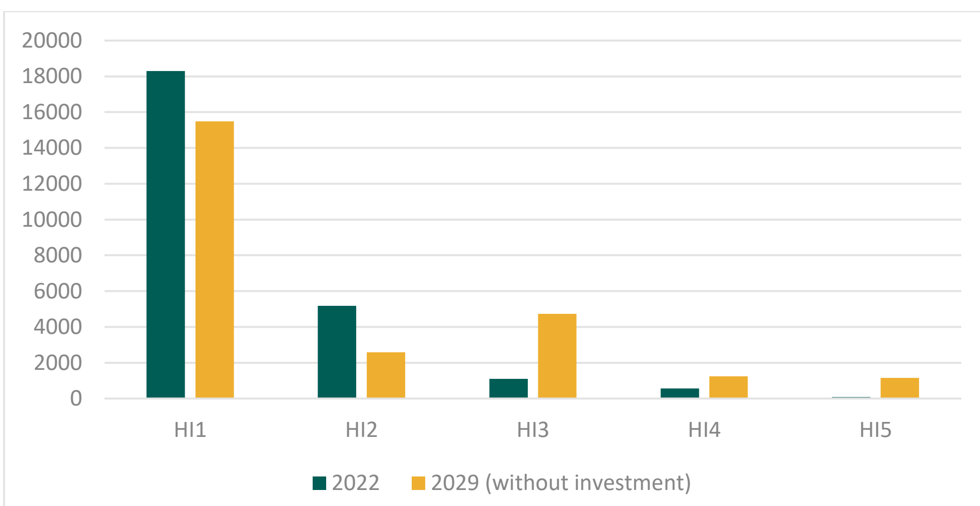


Figure 20: Asset Condition of Underground Transformers in 2022 and 2029 (without investment)

Toronto Hydro plans to replace approximately 2,500 underground transformers under this program over 2025-2029. This will be achieved through area rebuilds on 27.6 kV feeders and voltage conversions of 4.16 kV and 13.8 kV feeders, along with spot replacements of PCB transformers and transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and which are not part of any rebuild project.

E6.2.3.3 Replacement of Underground Switches

Toronto Hydro also plans to replace switches as part of area rebuild projects. There are approximately 3,138 switches in service in the Horseshoe area.

Switches are critical components of Toronto Hydro's distribution system and are used for load switching, isolation, and emergency power restoration procedures. There are two types of switches used in the underground Horseshoe system: (1) padmounted switches (either air vented or sealed with SF_6 insulation) primarily installed next to boulevards for feeder switching; and (2) vault installed switches (either air vented or sealed with SF_6 insulation) used for switching and transformer isolation within a vault. The useful life of these switches is 40 years.

Switches in Toronto Hydro's underground system are exposed to harsh environmental conditions such as contamination and moisture, which can reduce their useful life. Air-vented padmounted switches, for instance, are designed to be vented naturally through louvers under the hood of the enclosure. However, this is also a route for dust and road salt to enter the switching compartments and accumulate within the switch. Although scheduled preventive maintenance, such as inspections followed by corrective CO_2 washing, can remove excessive buildup of contaminants for a limited time, repeated CO_2 washing can contribute to the degradation of the switch's insulation strength, eventually leading to failure.

As the ambient temperature changes, the trapped moisture in the enclosure condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and may result in a flashover of the unit, potentially leading to failure.

A flashover in a padmounted switch can lead to a near simultaneous ignition of all combustible material within the compartment. This discharge of electrical energy can then spread to the other compartments of the switch, causing additional flashovers and combustion, ultimately resulting in the total failure of the unit. Figure 21 provides an illustration of how contaminants build up on a typical air-vented padmounted switch that could lead to a potential flashover.

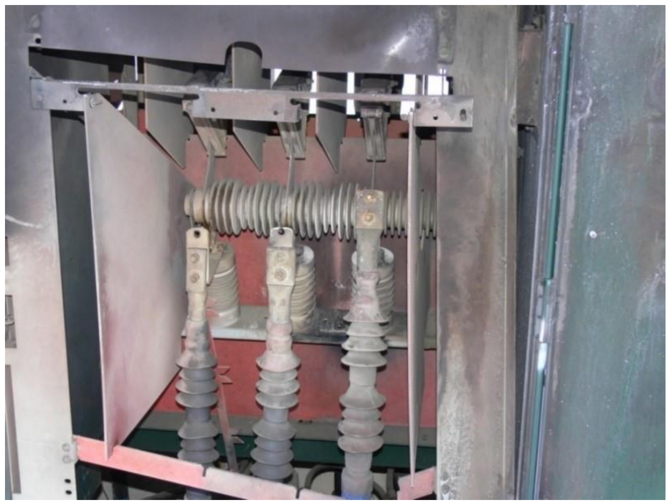
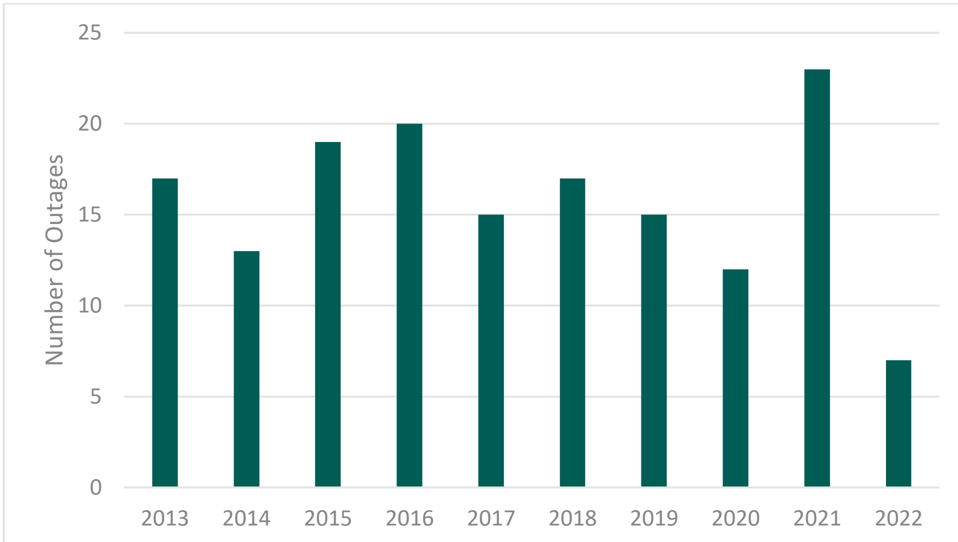


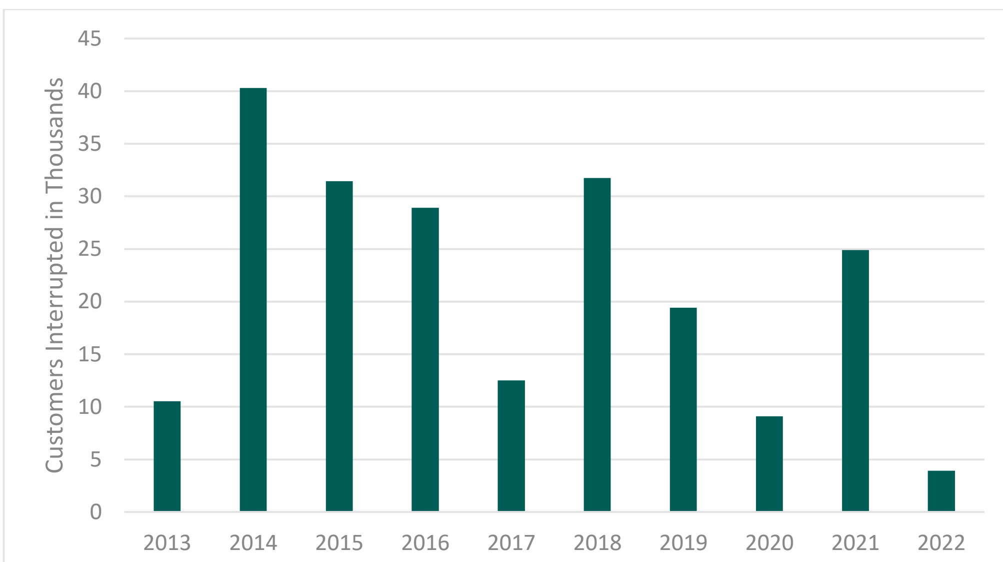
Figure 21: Padmounted switch with contaminant build-up

In Toronto Hydro's underground distribution system in the Horseshoe area, 5.8 percent of the underground outages between 2013 and 2022 were caused by switch failure. Depending upon the location of the switch, whether on the trunk or lateral portion of a feeder, a failure can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching and can lead to significant negative effect on system reliability by causing an outage, or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figures 22 to 24. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failures. However, the population of switches in service is aging and if Toronto Hydro does not continue to renew them proactively, the utility expects that the current level of reliability performance will not be sustained as failure rates increase.



1 **Figure 22: Ten-Year Trend of Outages due to Underground Switch Failures**



2 **Figure 23: Ten-Year Trend of Total CI due to Underground Switch Failures**

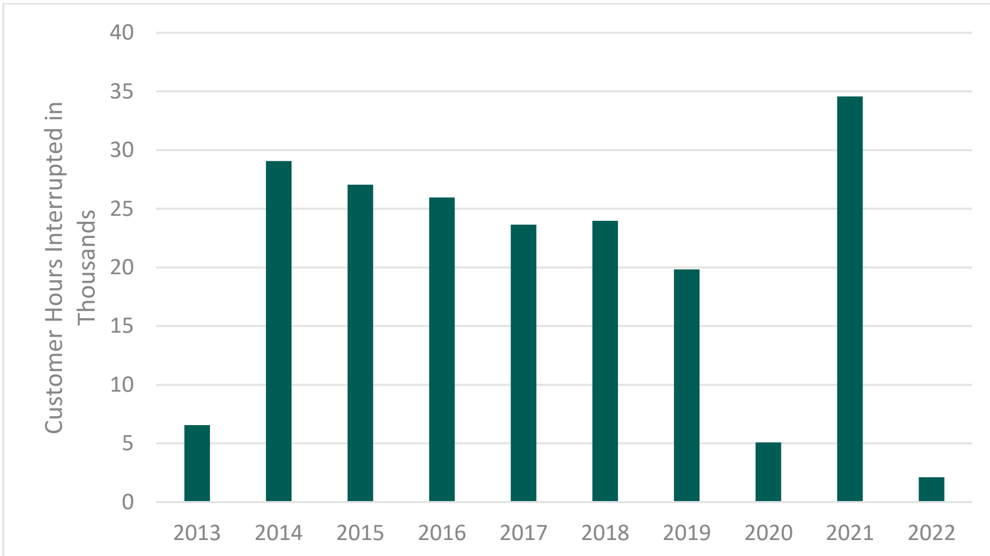


Figure 24: Ten-Year Trend of Total CHI due to Underground Switch Failure

Figure 25 and Figure 26 show the age demographics of all padmount and vault switches, which both have a useful life of 40 years. As of 2029, 86 padmount switches and 595 vault switches will be beyond useful life without investment.

Figure 25: Age Distribution of Padmount Switches in Underground Horseshoe System

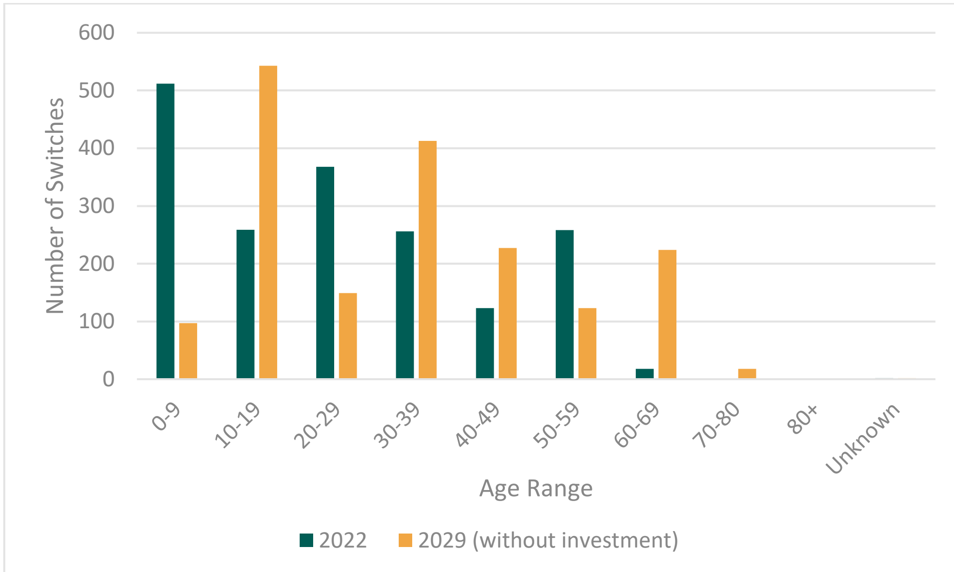


Figure 26: Age Distribution of Vault Switches in Underground Horseshoe System

Toronto Hydro's experience with padmount switches indicates that the majority of these units fail before their expected useful life. Toronto Hydro investigated 359 padmount switch failures that occurred between 2013 and 2022. The results of this analysis (see Figure 27) show that majority of padmount switches failed before the end useful life (40 years) and typical failures are attributed to external factors such as weather, contamination, and corrosion.

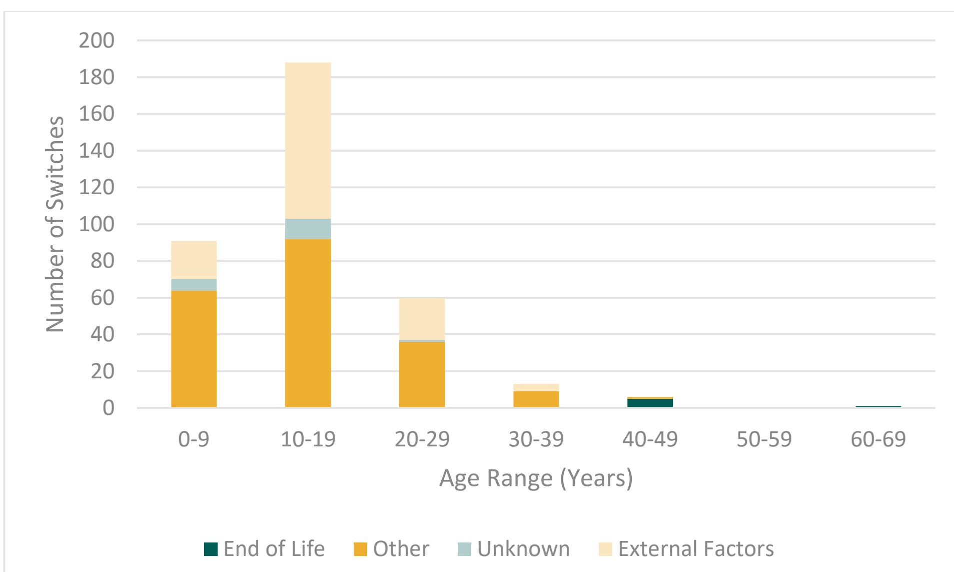


Figure 27: Age and Cause of Failure for Failed Padmount Switches from 2013 to 2022

Condition data for Air and SF6 type underground padmounted switches are shown in Table 6 and Figure 28. There are 70 padmounted switches in HI4 and HI5 as of the end of 2022 and, without investment, that number will almost double to 134 by 2029. An increased number of padmount switches with at least material deterioration will elevate the risks of units failing and therefore, without investment the recent improvements in switch-related reliability will likely erode and eventually reverse.

Table 6: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type

Condition	UG Switch Padmounted Air		UG Switch Padmounted SF6		Total 2022	Total 2029
	2022	2029	2022	2029		
HI1 – New or Good Condition	355	346	635	635	**990**	**981**
HI2 – Minor Deterioration	4	11	0	0	**4**	**11**
HI3 – Moderate Deterioration	64	2	0	0	**64**	**2**
HI4 – Material Deterioration	24	13	1	0	**25**	**13**
HI5 – End-of-Serviceable Life	29	104	16	17	**45**	**121**
Grand Total	**476**	**476**	**652**	**652**	**1128**	**1128**

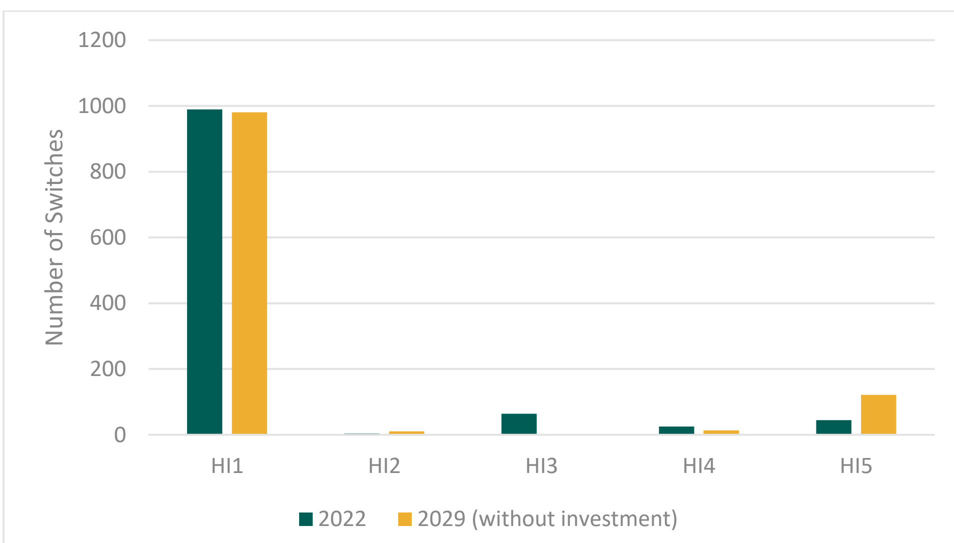


Figure 28: Asset Condition of Underground Switches in 2022 and 2029 (without investment)

To address the risks associated with air vented padmounted switches, Toronto Hydro plans to replace them with the new generation of SF_6-insulated switches. These new switches feature a stainless-steel enclosure to prevent premature rusting and degradation of the cabinet. The unit includes welded viewing windows that mitigate SF_6 gas leakage into the environment. Programmable relays are also used for downstream circuit protection, eliminating the need for on-site switch re-fusing after a fault on the branch circuit. The units have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

The new SF_6 switches also enable SCADA capability for remote sensing, leading to increased system efficiency and improving restoration time in the event of a power failure, while avoiding costs associated with crews physically operating the switch on site. Another advantage of padmounted SF_6 insulated switches is that they have the same circuit configuration and footprint as the existing air insulated padmounted units, thereby avoiding unnecessary cable and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require routine CO_2 washing to remove accumulated contaminants.

To mitigate environmental risks related to SF6 insulated gear, Solid Dielectric ("SD") switchgear is being trialed as an alternative. The SD gear shall have the same SCADA capability as the SF6 gear and shall maintain the same circuit configuration and foundation design to avoid unnecessary cable and civil construction work.

Toronto Hydro plans to replace approximately 116 padmount switches over 2025-2029 as part of area rebuild projects under this Program. The remaining padmounted switches and vault switches that have at-least material deterioration and are not part of the rebuild scope will be replaced through the Reactive and Corrective Capital program[17] upon failure as they do not present environmental risks.

E6.2.4 Expenditure Plan

Table 7: Historical & Forecast Program Cost ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground System Renewal Horseshoe	73.5	50.9	64.4	92.3	78.7	92.6	82.3	93.8	101.1	105.9

[17] Exhibit 2B, Section E6.7.

E6.2.4.1 2020-2024 Variance Analysis

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $351.8 million in the Underground System Renewal program, which is approximately $108 million lower than planned in the 2020-2024 Distribution System Plan. Toronto Hydro reduced the Program budget to support meeting the utility's capital funding limits while managing overall risk on the distribution system. In particular, this involved shifting away from direct-buried cable replacement, while still prioritizing underground transformers at risk of containing PCBs.

Over the 2020-2022 period, Toronto Hydro spent $188.8 million and installed 325 kilometres of underground cable in duct, 1,013 transformers, and 127 underground switches, as shown in Table below. Toronto Hydro plans to invest another $163 million in 2023-2024.

Table 8: 2020-2024 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge		Total
		2020	2021	2022	2023	2024	
Total Cable	*km*	114	83	128	175	63	563
Direct-Buried Cable[18]	*km*	29	32	18	13	13	105
Transformers	*Units*	307	425	281	406	361	1677
Switches	*Units*	55	20	52	18	17	162

As noted above, the utility has been prioritizing replacement of underground transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, challenges acquiring transformers has reduced Toronto Hydro's ability to ramp up the pace of replacements as intended, resulting in a notable decrease in units completed in 2022. The utility has been working diligently to mitigate the impacts of supply chain issues (see Exhibit 4, Tab 2, Schedule 15) and while the utility expects to increase the pacing in 2023, it is still on track to replace fewer transformers than originally planned. In addition, with the reduced budget and focus on PCB transformers, Toronto Hydro invested less in area rebuilds, resulting in less direct-buried cable and fewer switches replaced than proposed in the 2020-2024 DSP.

[18] Note that the Direct-Buried Cable amounts in this table are a subset of the Total Cable amounts in the row above.

More broadly, unit volume and cost variances can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2025-2029 Forecasts

Toronto Hydro plans to spend $475.7 million in this Program over the 2025-2029 period. The 2025-2029 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience with executing this type of work over recent years. The estimated volumes for major underground asset replacements during the 2025-2029 period are shown in Table 9.

Table 9: 2025-2029 Estimated Volumes (Forecast) – Underground System Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2025	2026	2027	2028	2029	Total
Total Cable	*km*	30	72	84	79	75	**340**
Direct-Buried Cable	*km*	25	38	45	35	39	**182**
Transformers	*Units*	870	352	346	429	481	**2,478**
Switches	*Units*	12	22	28	26	28	**116**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds on 27.6 kV feeders, rebuilds with voltage conversion, and spot replacements.

- **Area Rebuilds on 27.6 kV Feeders:** Area rebuild projects involve the prioritization and replacement of major assets such as cable, switches, and transformers, in areas where historical failures and deteriorated asset conditions pose particularly high risk to reliability. Area rebuilds ensures Toronto Hydro is able to coordinate work in an area and efficiently mobilize crews to minimize customer outages. By replacing entire sections on the distribution system on the feeders selected for rebuild, Toronto Hydro can ensure that customers only undergo one planned outage as opposed to numerous outages resulting from reactive work or spot replacements.

- **Area Rebuilds with Voltage Conversion:** Where a feeder identified for renewal through area rebuilds is operating on 4.16 kV and 13.8 kV voltages, it will be converted to 27.6 kV. Similar to area rebuilds, Toronto Hydro plans to select 4.16 kV and 13.8 kV for conversion based on historical performance, the number of assets that are in deteriorated condition or at or beyond useful life, and potential impact on customers supplied by the feeder for area conversion.
- **Spot replacement:** Transformers that need replacement but are not part of area rebuild projects will be addressed on a case by case basis through spot replacement projects. These projects will focus on replacing assets that are identified as having at-least material deterioration or pose environmental risks due to oil leaks. Spot replacement projects aim to reduce the likelihood of failures and mitigate the risk of negative environment impacts from oil leaks.

Once Toronto Hydro has removed all underground transformers containing PCBs, it will shift back towards an approach that includes more rebuilds focused on direct-buried cable and limiting spot replacements to only the worst condition transformers not addressed elsewhere.

Whenever possible, work under this Program is combined or coordinated with projects from other programs (such as overhead renewal and rear lot conversion) in the same area. Underground renewal projects are broken into civil and electrical phases, and those with significant amounts of civil work are broken down further into sub-phases for better manageability and coordination of resources.

Equipment in the same area and fed from the same Toronto Hydro feeders is coordinated in terms of replacement schedule and sequencing. This approach reduces disruption of supply and requires less mobilization of resources to the same area. Reduced disruption to feeders translates into fewer outages for customers, and improves project efficiencies. In addition, any voltage conversion underground work is coordinated with stations maintenance and capital work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major maintenance or renewal investments.

Once projects are scoped at a high level, they undergo a field inspection in order to validate the scope of work, identify third party conflicts, and refine estimates before design finalization. Through this process, projects identified for renewal may be subject to change, and poorly performing feeders that demonstrate higher risks may take priority.

E6.2.5 Options Analysis

Toronto Hydro considered the following options for the Underground System Renewal program. Under each of these options Toronto Hydro would seek to replace all remaining underground transformers containing, or at risk of containing, PCBs by the end of 2025 and will only replace switches proactively through area rebuilds (i.e. no spot replacement of underground switches).

E6.2.5.1 Option 1: Limited Area Rebuilds (15 feeders), Voltage Conversion (14 feeders) and Spot Replacements of PCB Transformers Only

Under this option, Toronto Hydro would rebuild 29 feeders, including the conversion of 14 feeders operating on 4.16 kV and 13.8 kV voltages to 27.6 kV. With this approach, Toronto Hydro would replace 140 km of cable, of which 98 km is direct-buried (15 percent of total direct-buried cable remaining as of 2022) and 42 km is cable in concrete-encased ducts beyond useful life. At this pace, it would take 30-35 years to eliminate all the direct-buried cable from the system, during which time customers would be exposed to increasing reliability risk as the cables continue to age. There would also be 237 km of cable in concrete-ducts beyond useful life remaining in the system by 2029 compared to 121 km under Option 2.

This option will lead to minimal improvement in cable failures wherein only limited sections of direct-buried cable and cables beyond useful life will be replaced. Given the significant contribution of cables to underground outages and the 542 km of direct-buried cable remaining and 7.6 percent of cables in concrete-encased ducts beyond useful life by 2029 under this option, the utility expects there would be higher costs and disruptions to the public and customers for reactive work.

This option also includes spot replacements of the remaining transformers containing PCBs. Although planned rebuilds will address some transformers past useful life and/or with at least material deterioration, there will continue to be a significant number remaining on the system, increasing the risks of failures and reversing recent improvements in transformer-related reliability and oil spills.

While this option's pace of investment would reduce program costs significantly, the resulting increases to reliability risk and expected impact on customers is not aligned with customer preferences, which includes reliability as a top priority.

E6.2.5.2 Option 2 (Selected Option): Area rebuilds (29 feeders), Voltage Conversion (29 feeders), Spot Replacement of Both PCB and Materially Deteriorated Transformers

Under this option, Toronto Hydro plans to rebuild 58 feeders, including 29 feeders converted to 27.6 kV. With this approach, Toronto Hydro will replace 340 km of total underground cable in the Horseshoe, out of which 182 km will be direct-buried cable (21 percent of total direct buried cable as of 2022) and 158 km will be cable in concrete-encase ducts beyond useful life. At this pace, it will take 20-25 years to eliminate all of the direct-buried cable from the system and there will be an estimated 121 km of cable inside concrete-encased ducts that is beyond useful life by 2029.

Toronto Hydro projects that under this option there will be 458 km of direct-buried cable remaining on the system and 3.8 percent of cables in concrete encased ducts will beyond useful life by 2029. Although, this is still a significant amount of direct-buried cable and end-of-life cable left in the system, it is an improvement over Option 1 and would mitigate the expected reliability impacts of that option. Toronto Hydro finds this pace of cable renewal to be the most reasonable balance between outcomes such as reliability and costs.

Under this option, Toronto Hydro plans to replace approximately 2,500 underground transformers through area rebuilds and through spot replacements of transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and are not part of any rebuild project. This will also include the remaining 492 underground transformers in the Horseshoe area that contain (or are at-risk of containing) PCBs. This option will mitigate the potential accumulation of a large backlog of transformers that are at a high risk of failure and in need of replacement beyond 2029 as well as mitigate the environmental risks associated with leaking oil.

E6.2.5.3 Option 3: Area rebuilds (30 feeders), Voltage Conversion (38 feeders), more DB cable replacement, spot replacement of remaining transformers containing PCB along with assets with at-least material deterioration at the end of 2029

Under this option, Toronto Hydro would fully rebuild a total of 68 feeders, 38 of which would be converted to 27.6 kV. With this approach, Toronto Hydro would replace 375 km of total cable, out of which 215 km is direct-buried cable (32 percent of total direct-buried cable remaining as of 2022) and 160 km is cable in concrete-encased ducts beyond useful life. At this pace Toronto Hydro would eliminate all direct-buried cable within 15-20 years and would reduce the cable inside concrete ducts beyond useful life to 119 km by 2029.

Under this option, the amount of direct-buried cable remaining in the system would be reduced to 425 km by 2029, improving expected reliability relative to the other options.

This option also includes the spot replacement of any remaining underground transformers containing PCBs along with any additional transformers remaining in the system that are projected to be HI4 or HI5 by 2029 without investment and that are not part of any rebuild project. The replacement of these remaining transformers not addressed through the rebuilds would help to reduce the risk of failures as well as to mitigate the environmental risks associated with leaking oil.

This option would ensure that Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the underground system that are supplied by 4.16 kV and 13.8 kV. While this option is the best one for mitigating reliability and environmental risk, the cost is much higher and it does not represent a balanced trade-off between risk mitigation and price.

E6.2.6 Execution Risks & Mitigation

Project execution begins with the civil phase of the underground renewal project. Electrical construction commences upon completion of the civil work. The risks associated with the Underground System Renewal program include, but are not limited to:

- Unforeseen updates and changes to existing road moratoriums imposed by the City of Toronto in areas where Toronto Hydro intends to perform underground renewal work. To mitigate this risk, Toronto Hydro will coordinate closely with the City of Toronto and its representatives, i.e. Ward Councillor, Business Improvement Area delegates.

- Unforeseen weather conditions that may affect Toronto Hydro's ability to carry out planned outages. Extreme weather conditions such as heat restrictions during summer or harsh winter storms, can also impact construction schedules. Toronto Hydro addresses this risk by closely monitoring weather forecasts and making necessary adjustments to the construction schedule to minimize the impact of adverse weather conditions.

- Third-party conflicts may require Toronto Hydro to modify its trench route due to underground space limitations, resulting in higher than estimated project costs. Toronto Hydro mitigates this risk by engaging with third parties in the design phase to ensure close coordination and alignment. This involves participation in the Toronto Public Utility Coordinating Committee meetings to identify and avoid third party conflicts.

- Some projects require work within customer owned civil structures or consent on easements from customers to install distribution assets on private property. In the case of customer-owned civil structure, the customer may have to perform civil rebuild work prior to Toronto Hydro commencing its activities, causing project delays. Toronto Hydro mitigates this risk by inspecting customer owned assets during the design phase and communicating to the customer by issuing Customer Advice Form ("CAF") for any deficiency identified. This ensures that customers are given advanced notice and have an opportunity to raise their concerns and address the civil work in a timely manner. For permits and easements, Toronto Hydro will reach out and engage customers early in the design phase of the project to account for the possibility of delays. This gives customers the opportunity to meet with the utility to discuss the details of the project and any concerns. This proactive customer engagement approach has been successful in minimizing construction delays.

- All underground projects are designed and constructed in accordance with approved Toronto Hydro's standards and specifications. However, in certain cases, deviations or special considerations are needed during design. Toronto Hydro will follow its established process for all deviation requests so that they can be assessed and approved by the standards department in a timely manner during the design phase. This process helps to prevent delay or costly rework due to operational issues during the execution of the projects.

- Longer lead time for material, especially underground transformers, can seriously impact project execution, resulting in delays or deferrals into future years. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.3 Underground System Renewal – Downtown

E6.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 80.6	**2025-2029 Cost ($M):** 165.1
Segments: Cable Chamber Renewal, Underground Cable Renewal, Underground Residential Distribution Renewal, Underground Switchgear Renewal	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety	

The Underground System Renewal – Downtown program (the "Program") addresses aging, deteriorating and poor performing underground distribution assets in the downtown core area of pre-amalgamation City of Toronto.[1] This Program continues rebuild and replacement activities for deteriorating and functionally obsolete underground assets in the City's core. Starting in 2020, most of these assets have been managed through a combination of preventative maintenance, targeted refurbishment, planned system renewal and in the event of asset failure, reactive and corrective capital and maintenance programs.[2][3][4] The average condition of these assets (in addition to other pressures discussed below) necessitates a targeted renewal strategy; targeting worst performing and highest risk areas.

The Program is designed to maintain reliability, mitigate asset failure and public safety risks within the downtown core by: (1) replacing obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene ("TRXLPE") cables, (2) reconstructing cable chambers (or components; e.g. roofs, duct banks) at risk of failure due to poor structural conditions, (3) proactively replacing end-of-life and obsolete underground residential distribution ("URD") assets, and (4) proactively replacing end-of-life and obsolete underground switchgear.

The Program is grouped into the four segments summarized below:

[1] This Program does not address network units or network vaults. Network equipment is addressed within the Network System Renewal program (Exhibit 2B, Section E6.4)
[2] See Exhibit 4, Tab 2, Schedules 1, 2, and 3 Preventative and Predictive Maintenance programs
[3] See Exhibit 2B, Section E6.7
[4] See Exhibit 4, Tab 2, Schedule 4 Corrective Maintenance

- **Underground Cable Renewal:** The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP"). This segment replaces obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene cables. Based on the age and condition of Toronto Hydro's population of lead cables, the utility anticipates a decline in reliability performance and an increase in operational and safety risks. Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $61 million over the 2025-2029 period to replace approximately 3.5 percent of 985 km paper-insulated lead-covered ("PILC") cable and 5.3 percent of 176 km asbestos-insulated lead-covered ("AILC") cable. Replacement of legacy PILC and AILC cables will allow Toronto Hydro to maintain reliability performance by proactive replacement of high risk cables. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid. These cables are a critical part of the distribution infrastructure serving large customers (e.g. major financial institutions) and other reliability-sensitive customers (e.g. multi-residential high-rises) in the downtown core. Toronto Hydro uses risk-based prioritization, which considers historical failures, age, feeder uniformity based on cable type, and the magnitude and criticality of the load served by each feeder, to direct expenditures to the projects with the greatest customer value. In addition to removing lead-based cable, Toronto Hydro plans to install approximately 5 km of fiber optic cable to enable on line cable monitoring. On line cable monitoring will provide real-time thermal profile of cables and loading data which could be used for cable risk assessment and replacement prioritization in the future.

- **Cable Chamber Renewal:** This segment involves the reconstruction of cable chambers or cable chamber components (e.g. roofs, duct banks) that are at risk of failure due to their poor structural condition. Prior to 2020, Toronto Hydro managed the reconstruction of cable chambers reactively. However, due to the growing number of failing chambers and the complexity of chamber reconstruction work, Toronto Hydro introduced a planned renewal segment in 2020. The vast majority of chambers in Health Index ("HI") band 4 (material deterioration) and HI5 (end of serviceable life) condition are located in the downtown core, where there is heavy vehicular and foot traffic and a high density of circuits running through each chamber.[5] These chambers can hold up to 29 circuits, supplying up to 3,500 customers

[5] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these

per chamber. Typically, these are chambers that supply large condominiums with many suite-metered residential customers. Chambers can also supply one or several large industrial or commercial customers. As of 2022, 592 cable chambers were in HI4 or HI5 condition and this is projected to grow to 1,113 by 2029 without investment. To mitigate this growing backlog and associated safety and reliability risk, Toronto Hydro plans to address 199 cable chambers or cable chamber components. Toronto Hydro also plans to replace 2,800 cable chamber lids to address the public safety risks in high traffic areas. The total forecast cost for this segment is $96.5 million.

- **Underground Residential Distribution ("URD") Renewal:** This segment is focused on the URD system – a unique looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto. Prior to 2020, Toronto Hydro managed the replacement of URD assets on a reactive basis. However, due to the growing number of failing URD vault roofs, severe corrosion, deteriorating and obsolete equipment, Toronto Hydro introduced a planned renewal segment in 2020. The utility plans to invest approximately $4.8 million over 2025-2029 to proactively replace end-of-life and obsolete URD assets that contribute to the deterioration of URD system reliability, namely switching and non-switching vaults, switches, and transformers. In addition, Toronto Hydro plans to install new Faulted Circuit Indicators ("FCIs") on URD feeders that experience the most outages. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by this system. The utility aims to achieve this by targeting the worst condition, obsolete, and most critical URD assets.

- **Underground Switchgear Renewal:** This segment replaces underground switchgear in customer owned vaults that feed apartment buildings, educational facilities and community centres. To date, Toronto Hydro has managed the replacement of this type of assets on a reactive basis. However, due to the growing number of deficiencies of underground switchgear where repairs are not an option and require replacement due to obsolescence, Toronto Hydro is introducing a planned renewal segment starting in 2025. The utility plans to invest approximately $2.9 million over 2025-2029 to proactively replace end-of-life and obsolete underground switchgear. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by

same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology these assets. The utility aims to achieve this by targeting the worst condition and most critical assets.

The Underground System Renewal – Downtown program for the 2025-2029 rate period is also aligned with the objectives of addressing environmental and safety risks associated with distribution assets containing PCB, lead, or asbestos. The total proposed investment for the Program in 2025-2029 is $165.1 million.

E6.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness – Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) and reduces the risk of lengthy outages on feeders serving thousands of downtown customers, including large, critical customers in the core while improving long-term system health by: ○ Replacing an estimated 35 kilometres of PILC cable that is subject to a high risk of failure. ○ Rebuilding/repairing/abandoning 199 cable chambers known to be in HI4 and HI5 condition. ○ Reducing the average number of transition joints on downtown feeders. ○ Replacing FCIs at end of service life on select URD feeders, enabling crews to quickly find faults and reduce restoration time. ○ Replacing 20 end of life and obsolete underground switchgear
Environment	• Contributes to Toronto Hydro's environmental objectives and reducing the risk of toxic exposure to the environment by: ○ Eliminating PILC cable containing oil and potentially PCBs; ○ Eliminating AILC cable containing asbestos; ○ Eliminating PILC and AILC cable containing lead; and ○ Replacing URD transformers containing oil. • Contributes to the utility's commitment to reduce greenhouse gas emissions by replacing URD switches containing SF6 gas.
Operational Effectiveness - Safety	• Contributes to the utility's public and employee safety objectives and performance by: ○ Replacing 2,800 chamber lids to reduce the risk of injury or property damage from cable chambers lid ejections;

	○ Eliminating safety hazards such as poor structural integrity and cable congestion; ○ Reducing the safety hazards related to the structural failure of cable chambers and URD vaults roofs in high-traffic areas by replacing or abandoning HI4/HI5 condition chambers, and chambers / vaults roof rebuild; and ○ Reducing the potential exposure to lead and asbestos (which are classified as Designated Substances under the Occupational Health and Safety Act6 (Ontario Regulation 490/09 Sections 5 and 10). ○ Safely handle and dispose of asbestos (and lead) as prescribed in the Ontario Occupational Health and Safety Act 7(Reg. 8338) and the Canadian Environmental Protection Act. ○ Replacing an estimated 4,000 cable splices thus reducing the risk of cable chamber lid ejections ○ Reducing the safety hazards related to arc flash incidents due to maloperation of underground switches by replacing HI4/HI5 underground switchgear.

E6.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Safety, Environmental Risk

The Underground System Renewal – Downtown program is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets had shown high reliability but have now become obsolete or pose a risk to the public and the environment. Many of these assets are vital to supply critical customers in the downtown district. These are of particular concern for both residential and large commercial customers who identify reliability as one of their top needs and the majority support investments that reduces outages as demonstrated through the customer engagement surveys.[9]

[6] RSO 1990, c. O.1
[7] *Ibid.*
[8] Control of Exposure to Biological or Chemical Agents, RRO 1990, Reg 833
[9] Exhibit 1B, Tab 5, Schedule 1

E6.3.3.1 Underground Cable Renewal

The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 DSP. This segment will focus on replacing obsolete primary PILC and secondary AILC underground cables at a high risk of failure with primary TRXLPE and secondary XLPE cable. These cables are typically found in the pre-amalgamation City of Toronto, especially throughout the downtown core.

PILC and AILC cables were initially installed in the downtown system due to their high reliability and long-life span. However, they are obsolete across the industry due to environmental and health and safety concerns (which includes the challenge of safely and skillfully working with lead). Major utilities are proactively eliminating lead cable, and only one PILC supplier remains (there are no longer any suppliers of AILC cables). Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Aged cables are showing signs of deterioration, including pin holes, cracks, and leaks.

Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5.3 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) between 2025 and 2029. The cables will be replaced based on the risk level associated with each feeder. A prioritization model has been developed by Toronto Hydro to rank primary feeder cable segments based on various factors, including historical failures, cable types, number of transition splices on feeders, age and customer base. In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections.

PILC cable consists of a conductor surrounded by oil-impregnated paper insulation, lead sheath and an optional linear low-density polyethylene jacket. There are approximately 985 circuit-kilometres of 13.8 kV PILC underground cable on the system. These cables were used as the primary service cable in the downtown core, connecting transformer stations to customers or Toronto Hydro owned distribution transformers (these transformers step down voltage and supply residential customers). Approximately 51 percent of all primary cable in the downtown core is PILC cable and approximately 49 percent is XLPE cable.

Figure 1 shows the distribution of PILC cable in the City of Toronto and the level of risk associated with them based on the type of cable, age, number of splices and reliability record. The highest risk cable segments (15 percent of total PILC cable length) are found both within and around the downtown core, while the medium risk cable segments (41 percent of total) are heavily concentrated within the core, and the Financial District in particular.

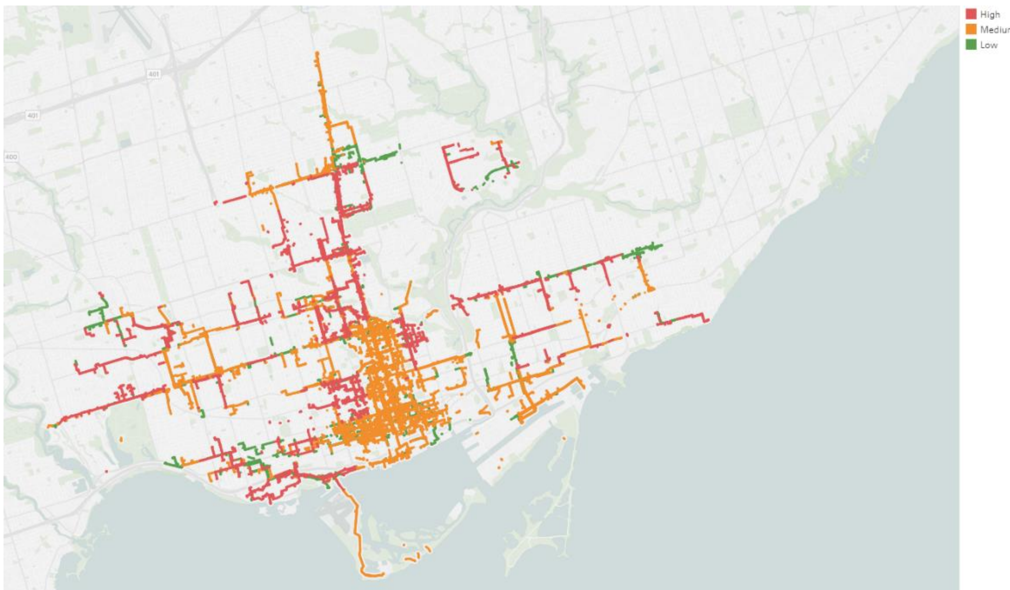


Figure 1: PILC Cable Distribution

AILC cables are found downstream of these PILC cables. They consist of a conductor (typically copper) surrounded by asbestos-based insulation and covered in a ductile lead sheath. These cables account for 40 percent of the secondary voltage connections within the secondary network system.[10]

Figure 2 represents the general distribution of all AILC cables in the city of Toronto and their level of risk based on the associated age and condition of primary assets. The majority of the AILC cable population is located in the core, whereas a small proportion is located north of the core.

[10] For more information on the Secondary Network System, please refer to Exhibit 2B, Section D2.2.3 of the Distribution System Plan.

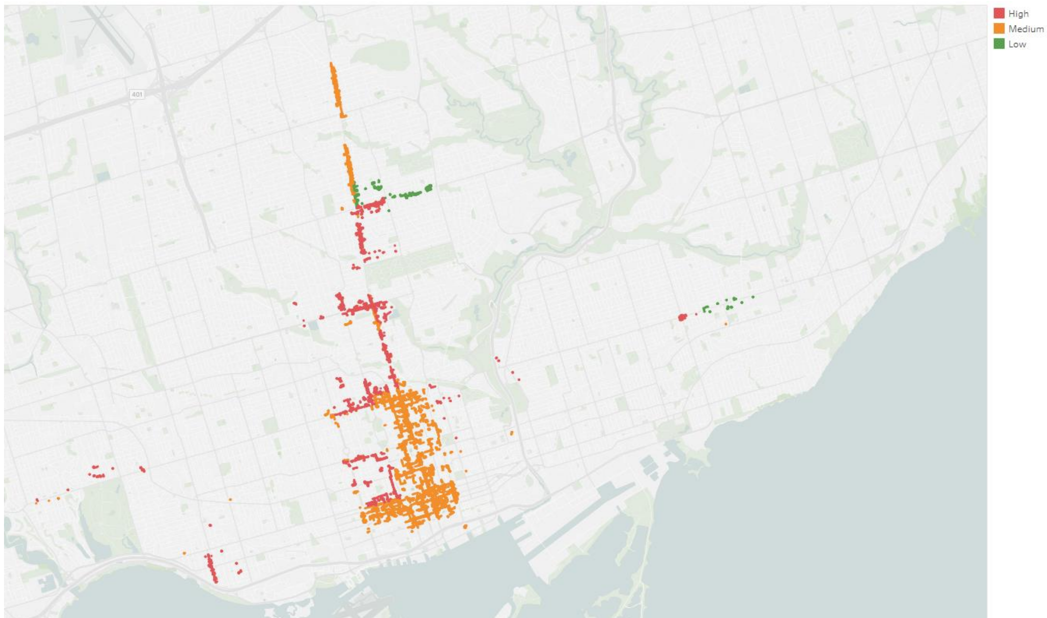


Figure 2: AILC Cable Distribution

Historically, PILC cable was used as it has good reliability record with a typical useful life of 65 years. However, the risk of failure for PILC cable increases if the PILC cable is modified. Due to the obsolescence of PILC and AILC cables, the necessary interventions and modifications to downtown feeders have unavoidably resulted in the splicing of XLPE cable into sections of PILC and AILC cable. Splicing is the process used to maintain the connectivity between two cable sections using joints for similar cable types and transition joints for different cable types. It is typically carried out when a longer cable is required, a branch is required, or part of an old cable is replaced with a new cable. This introduces non-uniformity of cable types and thus increases the risk of failure on the system as the majority of Toronto Hydro feeders with PILC and AILC cables do not consist of 100 percent PILC or AILC; instead, a mixture of cable types is common (e.g. PILC and XLPE, or AILC and XLPE).

Table 4 summarizes the programs and types of work that lead to a mix of cable types on Toronto Hydro feeders.

Table 4: Work conducted on Toronto Hydro feeders that lead to mixed cable types

Programs	Description of Work
Customer Connections (Exhibit 2B, Section E5.1)	• Customers are connected with new XLPE type cable spliced to existing PILC cable. • This also includes the addition of XLPE cable for secondary network type connections (replacement of AILC cable).
Reactive Capital (Exhibit 2B, Section E6.7)	• Cable faults or leaking cables are repaired by cutting or piecing-out faulty sections, and replaced with new XLPE cable, using splices.
Load Demand (Exhibit 2B, Section E5.3)	• Cable sections that require upgrades due to capacity limitations are replaced with new XLPE cable.
Network System Renewal (Exhibit 2B, Section E6.4)	• Circuit reconfigurations, required to achieve network stability and improved reliability, involve splicing new secondary and primary XLPE cable into existing AILC and PILC cables. • Network unit replacements include the replacement of critical AILC or PILC type cables that are connected to these units. • Cables to the most upstream cable chamber are replaced resulting in the introduction of splices.

As a result of the work noted in Table 4, lead cables become more brittle and prone to cracking, and the number of transition joints or splices increases over time. These splices create and add weak points along the cable and introduce additional failure risk to already aging cables serving many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen. As the weakest point on a feeder, a cable joint may fail primarily due to mechanical stress or water ingress.[11] A fault in the joints may also impact the conductor, insulation, or sheath. For instance, the sheath of the joints can develop corrosion due to thermal stresses of the feeder, which increases the chance for moisture to seep into the joint and consequently cause a failure.

The introduction of mixed insulation types also introduces different dielectric strengths or inconsistent magnetic fields at the joints which would result in higher losses or insulation breakdown. These transition joints (splices) are critical to the continuity of the dielectric properties and magnetic field across cable sections. They require a lead sleeve for the cable section to maintain the insulation

[11] Nemati, H.M., Sant'Anna, A., & Nowaczyk, S. (2015). Reliability Evaluation of Underground Power Cables with Probabilistic Models, *The 2015 International Conference on Data Mining,* p. 37-43.

properties of PILC cable. This is to hold the oil from oil-impregnated paper and protect insulation as much as possible. If these sleeves are compromised, this can result in drying out of the impregnated paper and compromise the insulation properties. Furthermore, as cable sections age, they begin to experience thermal, environmental, or mechanical stresses. Since XLPE and lead cables have different properties, the transition joint on any given feeder experiences the most stress. For example, the Windsor TS feeder A-81-WR supplies seven large customers, and includes five transition splices and 25 lead joints, as shown in Figure 3 below. Failure at any of these splices or joints will result in an outage while crews switch customers to backup supply, which typically takes 2 to 4 hours and subsequently about 8 to 10 hours until full power is restored.

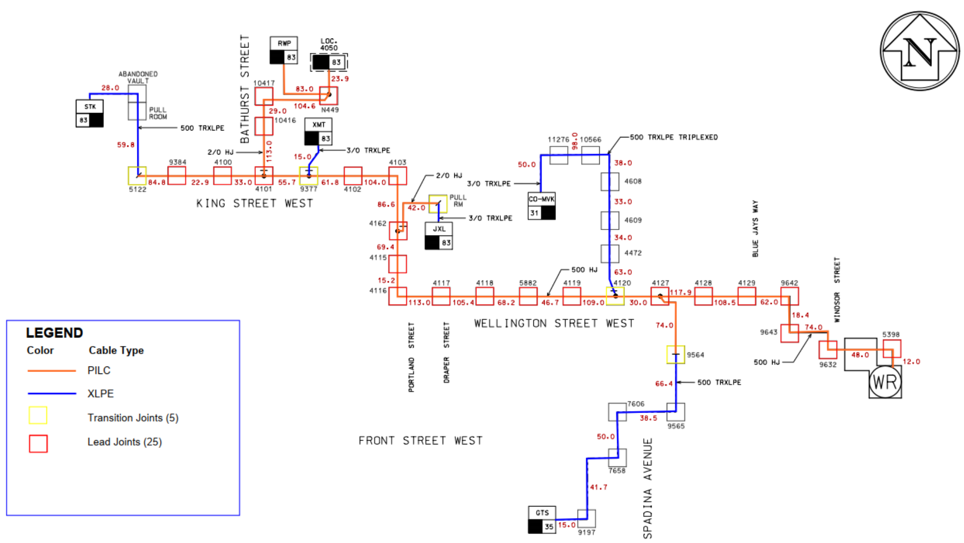


Figure 3: Schematic Feeder A-81-WR that depicts Transitional and Joint Splices

Figure 4 below illustrates examples of splices with deficiencies.

Figure 4: Sample PILC Joint with a Split Sleeve, i.e. Leaker (Left) and Collapsed Cable Splice (Right)

In addition to increased failure risk due to cable splicing, there is the risk of oil leakage from the insulation on PILC cables. Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of lead cables develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. On average, Toronto Hydro had to repair 30 such leaks per year between 2019 to 2022, a significant increase from the average of eight per year reported in the 2020-2024 DSP.

As shown in Figure 5 below, the failure rate of lead splices and transition joints per kilometre increases with the age of the feeder sections, i.e. the older the feeder cable and its splices, the higher the number of outages. The majority of these failures are due to moisture ingress, reduction in dielectric strength due to oil leaking from cracks and pinholes, as well as thermal stress.

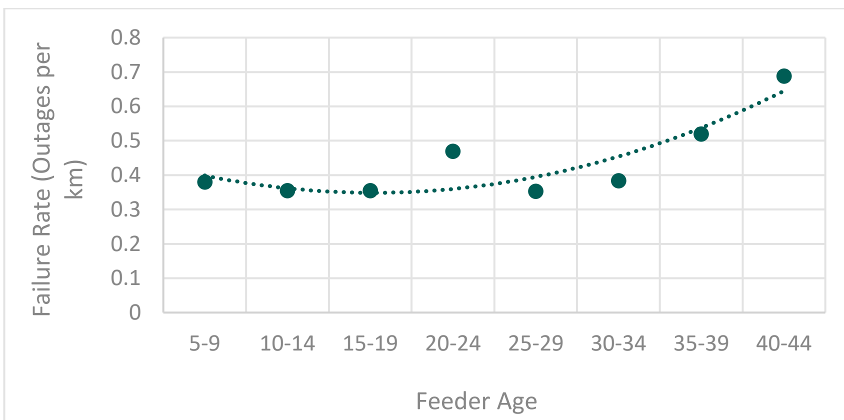


Figure 5: Failure rate of cable splices with PILC[12]

On average, there are 4 transition joints and 27 lead joints per primary feeder in downtown Toronto. By the end of 2029, given the PILC cable planned for replacement, Toronto Hydro expects to maintain the average number of transition joints at 4 and reduce the average number of lead joints to 24. Figure 6 and Figure 7 illustrate the current state of transition joints and lead joints in the system on feeders (though not all feeders are labelled therein). Figure 8 shows the comparison in number of transition splices per feeder between 2017 and 2023 for select feeders targeted for renewal over 2020-2024. The number of transition splices decreased for the four feeders already completed, while

[12] It is important to note that Toronto Hydro keeps a limited quantity of PILC cables on hand for extreme circumstances where reactive repair is required.

the fifth feeder, which has not yet been renewed, saw an increase due to work such as that listed in Table 4.

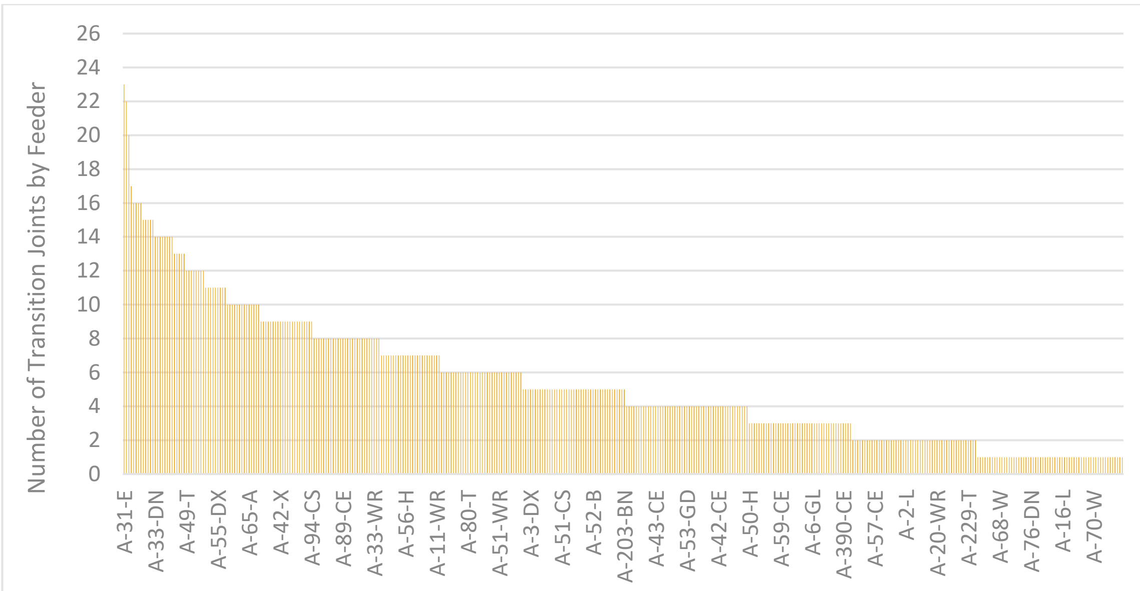


Figure 6: Transition Joints by Feeder

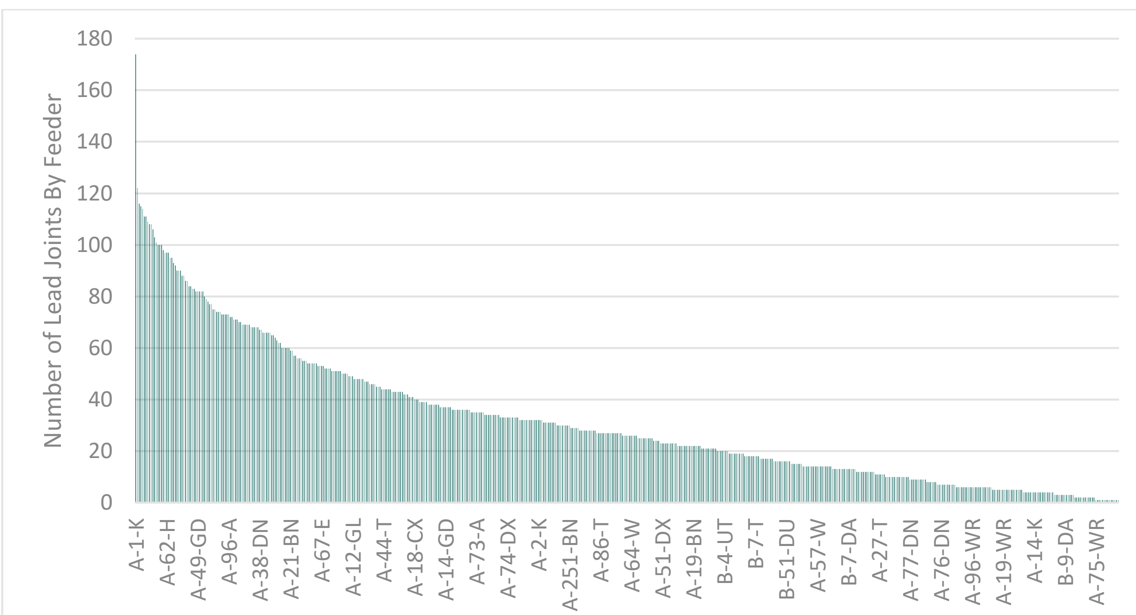


Figure 7: Lead Joints by Feeder

Figure 8: 2017 vs. 2023 Comparison of Transition Splices on feeders targeted for renewal over 2020-2024, with all except A33E now completed (A33E planned for 2024).

As shown in Figure 9, there are on average 44 reported cable or splice related failures per year, including on average 22 failures per year related to splices.

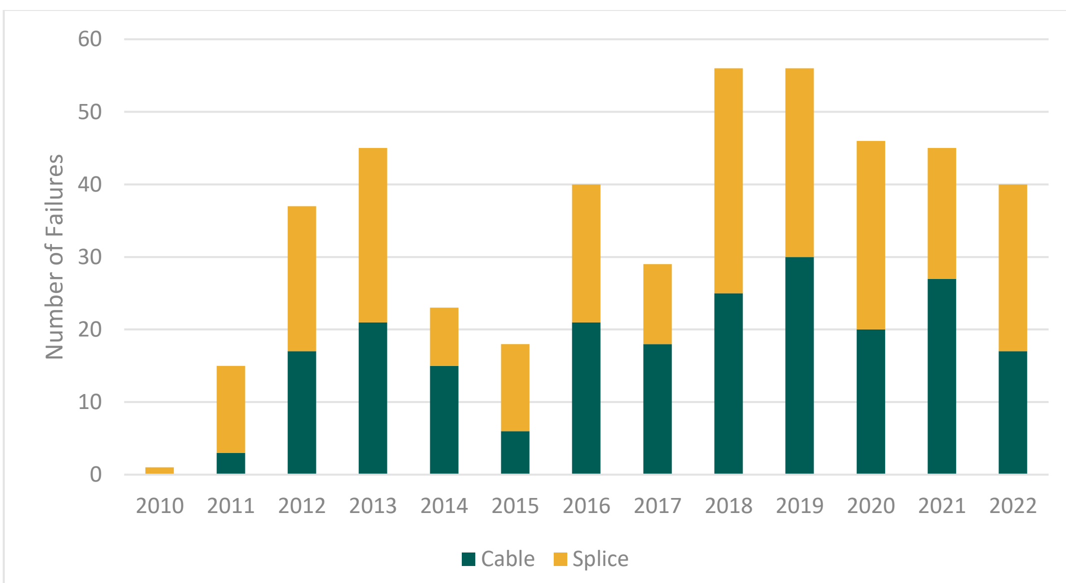


Figure 9: Number of PILC Cable/Splice Failures per Year

There were a total of 312 cable and splice failure incidents reported between 2016 to 2022 with an increasing trend of 55 incidents per year in years 2018 and 2019. The number of incidents per year has gradually reduced between 2019 and 2022 to 40 incidents per year. As per Figure 5, the number of failures per km rises with cable age. Quantitatively, this trend aligns with the qualitative observation by field personnel of the rise of failures as more splices are introduced while cable sections age.

Cable failures affect a wide range of customers, whose configuration of connection to the system depends on the feeder and the supply location and not necessarily customer type. Figure 10 below illustrates this using seven sample feeders. This segment aims to target feeders with large loads, such as A-81-WR, and introduce uniformity of cable by proactively replacing a large section of cable especially in the downtown core. This aligns with the customer engagement results where customers (especially large customers) prioritize reliability. Large multi-residential buildings are considered as large commercial customers here since minimal cable renewal investments will impact many end use customers.

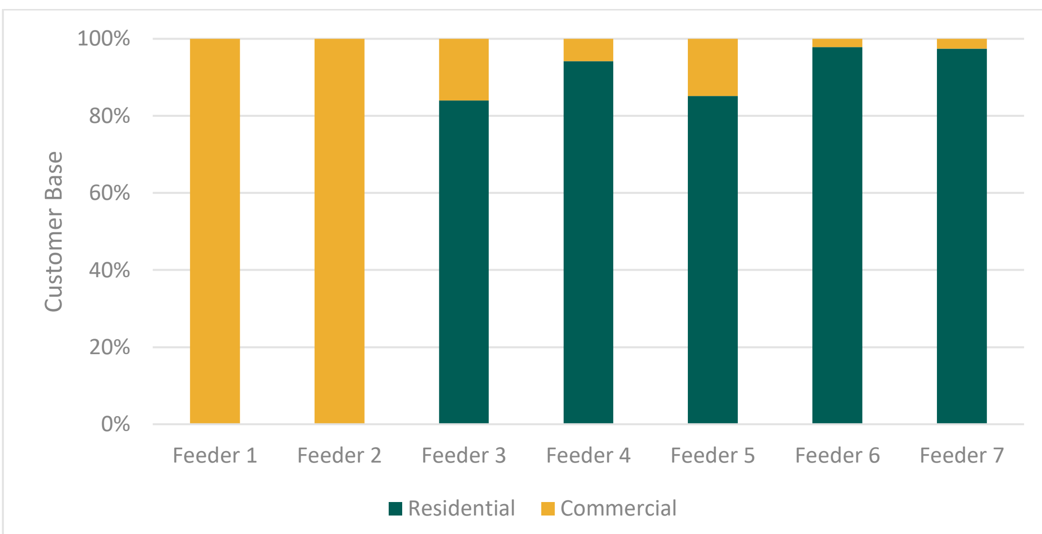


Figure 10: Composition of Customer Type of Circuits with PILC Cable

Lead-based cables (e.g. AILC and PILC) also need to be removed from the system due to a large functional obsolescence factor. Lead splicing typically requires highly qualified and trained individuals. Many utilities are facing a challenge training personnel with respect to lead splicing techniques. The skillset in the workforce is diminishing as lead cable is not actively introduced into the system. Furthermore, PILC cable is only supplied by one North American manufacturer at this time and a procurement problem may arise in the near future, while AILC cables are currently obsolete and are no longer supported by any manufacturers. Although Toronto Hydro stocks minimal PILC cable, it is not actively introduced into the system and primarily used for reactive replacements. There is also a risk in maintaining a large population of PILC cable in the long term if PILC cable becomes unavailable. This is because some segments of PILC cable cannot be replaced reactively with XLPE and TRXLPE cable due to duct or cable chamber size limitations or the condition of the underlying civil infrastructure. In recent years, due to lack of manufacturers it has been challenging to source splicing materials required for PILC joints and transition joints and as such, construction standards has been revised to limit PILC cable installation and use polymeric XLPE and TRXLPE cables where feasible. As noted above, this increases failure risk if these non-homogenous feeder types are not minimized.

These cables present both safety and environmental risks. Lead is a designated substance as per Ontario Regulation 490/09 (see section 10) and exposure should be minimized to mitigate the health risks. The risks of working with this substance alone is a potential safety hazard as lead needs to be exposed to high temperatures to complete a lead splice. This can create airborne fumes increasing the occupational and environmental exposure. Further, PILC cables manufactured prior to 1986 may contain PCBs within the oil. Toronto Hydro is committed to mitigating the risks of oil leaks containing PCBs. Leaking PILC cables also present risks to crew and public safety as the likelihood of arc flashes due to the deterioration of the insulation is high. Arc flashes are dangerous to crews and pose a safety risk to the public if leaking oil becomes ignited. Leaking oil is a sign of pending cable failure.

In addition to removing obsolete, lead-based cable, Toronto Hydro plans to install fiber optic cables in support of an online cable monitoring program. The program will utilize distributed temperature sensing technology (“DTS”) to obtain a continuous temperature profile of the fiber optic cables that are placed alongside underground cables. It will also provide partial discharge information of underground cables. Partial discharge is a common sign of insulation breakdown on underground cables and connections or weak spots in cables which eventually result in cost-intensive repairs and prolonged outages. The benefits of this technology are the following:

1. Increased observability on feeders by providing real time thermal loading of cable segments and thus allow operations and planners to assess feeder loading and available capacity for enhanced optimization of in-service assets.
2. Improved reliability as it would allow for proactive measures to be taken on cables such as identifying and replacement of at-risk cables before failure.

3. Reduce operating costs and planned outage times as it could defer offline cable testing activities.

The online cable monitoring technology depends on the presence of fiber optic cables along the cable route for monitoring and currently not all feeder routes have fiber optic cable. Through this segment, Toronto Hydro proposes installing 5 km of fiber optic cable over the 2025-2029 period in addition to the PILC cable replacement in routes where there is no existing fiber optic cable present. This would expand the fiber optic cable network and enable deployment of online cable monitoring to additional sections of the distribution system. The information provided by online cable monitoring technology could be used to enhance cable risk assessment and replacement prioritization processes in the future.

E6.3.3.2 Cable Chamber Renewal

The Cable Chamber Renewal segment will invest in the structural integrity of Toronto Hydro's high risk, poor condition (HI4 and HI5), and aging population of cable chambers by rebuilding the whole chamber or roof, or abandoning the chamber. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are approximately 10,657 cable chambers in Toronto Hydro's underground distribution system, of which approximately 74 percent are in the downtown area. These chambers hold up to 29 circuits each, supplying anywhere from 3,500 customers of different types and sizes, down to a few large industrial or commercial customers (e.g. financial institutions, hospitals).

Cable chambers have a useful life of 65 years, while chamber roofs have a useful life of 25 years, meaning that the roof will require a rebuild at least once during the useful life of the chamber as cable chambers are impacted by deterioration drivers such as road salts and vehicle loading. Figure 11 shows the cable chambers age demographic, as of 2022, for all cable chambers and roofs. Approximately 2,208 cable chambers are past their useful life and 6,643 cable chamber roofs are past their useful life.

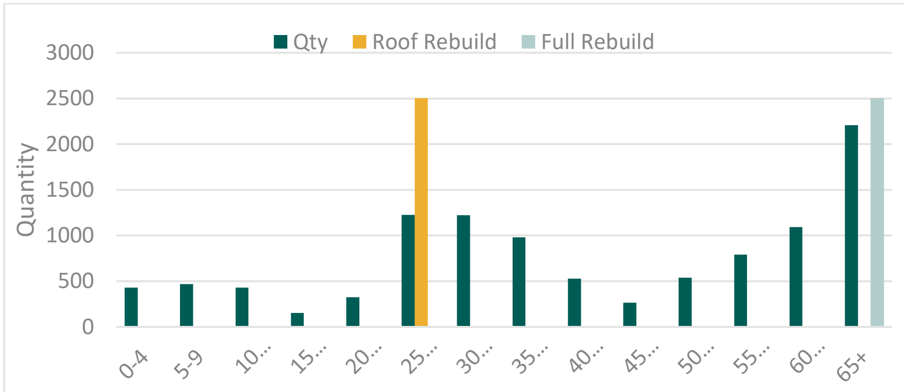


Figure 11: Cable Chambers Age Demographic

Toronto Hydro inspects cable chambers and cable chambers roofs on a planned 10-year cycle. The growing backlog of aging cable chambers is reflected in the observed condition of the assets. For many of its major assets, including cable chambers, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention.[13] Figure 12 below shows the asset condition of the 10,657 cable chambers in Toronto Hydro's distribution system as of 2022 and the projection for 2029. The data indicates that 592 cable chambers have condition classified as HI4 or HI5 and will require rebuild in the near-term. Furthermore, Toronto Hydro projects that there will be 1,113 cable chambers in HI4/HI5 band by end of 2029 without investment.

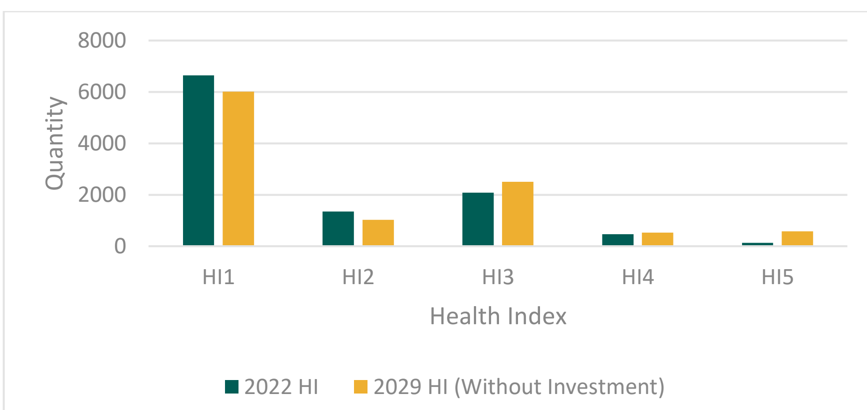


Figure 12: Cable Chamber HI Distribution (Actual and 2029 Forecast)

[13] See Exhibit 2B, Section D3, Appendix A for more details on Toronto Hydro's ACA methodology.

Depending on the severity of issues, Toronto Hydro ensures the time of rebuild is determined based on a holistic review of the structural condition of the chamber (even if it is classified as HI5). This means a cable chamber may require a reactive rebuild or temporary repairs to mitigate safety risks which would allow for a planned rebuild in the future.

Figure 13 below shows the high concentration of HI4 and HI5 condition chambers in the downtown core, where, as mentioned above, the chambers tend to carry a high concentration of circuits serving thousands of customers, or large customer loads. Should a chamber or chamber roof collapse to any extent, the equipment in the chamber could be damaged, leading to a potentially lengthy outage for the aforementioned customers.

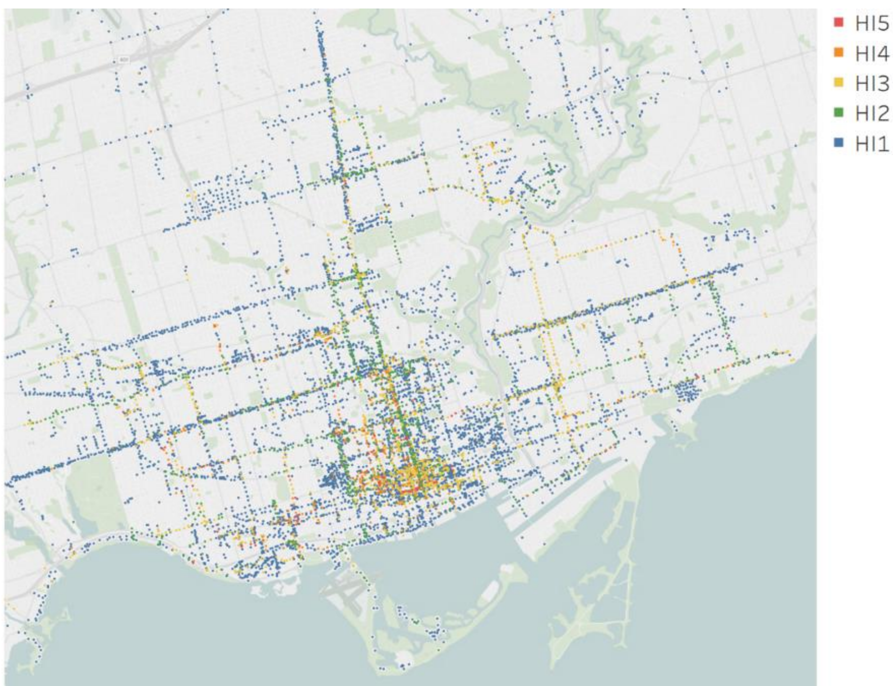


Figure 13: Cable Chamber Locations and Conditions

Of equal or greater concern is the risk to crew and public safety posed by a failing cable chamber. In areas of high vehicular or foot-traffic especially, a structurally unsound chamber or roof can create hazards to the public. The collapse of a chamber or chamber roof could have more severe consequences for the public or for crews working in the chamber. Figure 14 below shows an example of a severely deteriorated cable chamber roof.

Figure 14: Cable Chamber Roof in HI5 Condition (Left), and Roof Inside View (Right)

The images shown in Figure 14 are an example of a cable chamber with a reduced neck which is common when the City rebuilds or regrades roads. In this situation, when the asphalt was removed, a hole was discovered. This is very dangerous especially if the hole or deteriorated structure is covered by newly paved road.

Depending on the specific site, addressing a HI4 or HI5 condition chamber will include:

- **Full rebuild:** rebuilding the cable chamber civil structure, including its roof and duct banks, and involves some cable replacement; or
- **Roof rebuild:** rebuilding only the roof.
- **Cable Chamber Abandonment:** if the cable chamber is in a condition such that it cannot be brought to the current standard, it will be abandoned and a new chamber will be rebuilt beside it.

In addition to rebuilds, Toronto Hydro also plans to continue proactively replacing potentially hazardous cable chamber lids. Deteriorated cables running through cable chambers can fail, potentially causing arcing and igniting gases, which then can create a powerful shock wave. These shock waves can dislodge a chamber lid in a violent manner, ejecting it into the air and creating a serious public safety hazard. Since 2018, Toronto Hydro has recorded 26 incidents related to cable chamber lids, as shown in Figure 15. The utility is proactively replacing lids on cable chambers with an energy mitigating lid design to mitigate this ejection risk. Since 2020, Toronto Hydro has replaced 470 cable chamber lids with energy mitigating lids and plans to replace another 2,800 cable chamber lids over 2025-2029. The increased pace is required to address the safety hazard associated with the higher risk locations in a timely manner.

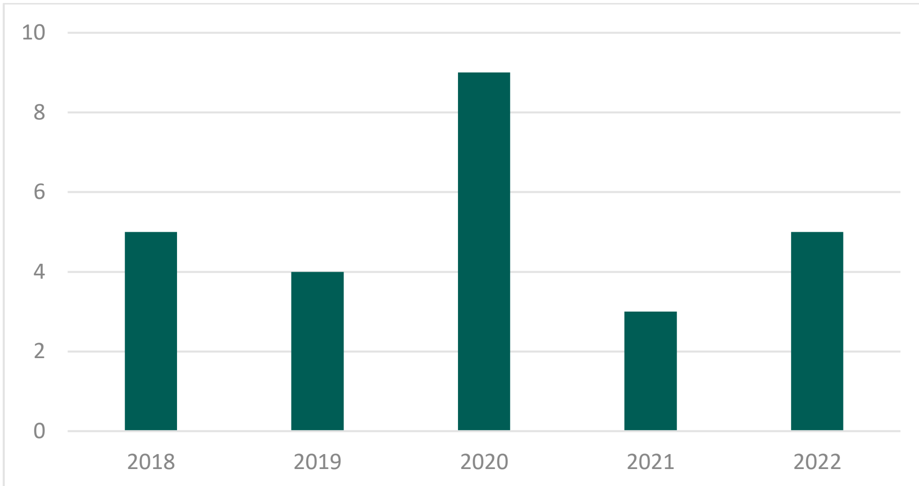


Figure 15: Number of Lid incidents

E6.3.3.3 Underground Residential Distribution ("URD") Renewal

This segment aims to replace deteriorating and obsolete URD assets that could negatively impact system reliability. These assets include: vaults, switches (including FCIs), and transformers that form part of the URD system. As per Toronto Hydro's customer engagement results, residential customers indicated that reliability is a top priority.[14] As such, specific areas of the URD system will be targeted for renewal in this segment to support maintaining the reliability performance of the URD system.

Introduced in the 1990s, the URD system was intended to replace the 4 kV overhead system supplying residential customers in the downtown area. The URD system is comprised of redundancies via main loops and sub-loops to add a level of robustness by isolating sections of the feeder.

The main underground system configurations are either radial or looped. However, system types and configurations are sometimes mixed to provide improved reliability or flexibility when repairs are required, as is the case with URD. In the URD system, primary cables, switches, and distribution transformers are placed underground while most secondary voltage connections remain overhead. This system only appears in limited areas throughout the pre-amalgamation City of Toronto, as seen in Figure 16 below.

[14] *Supra* note 9

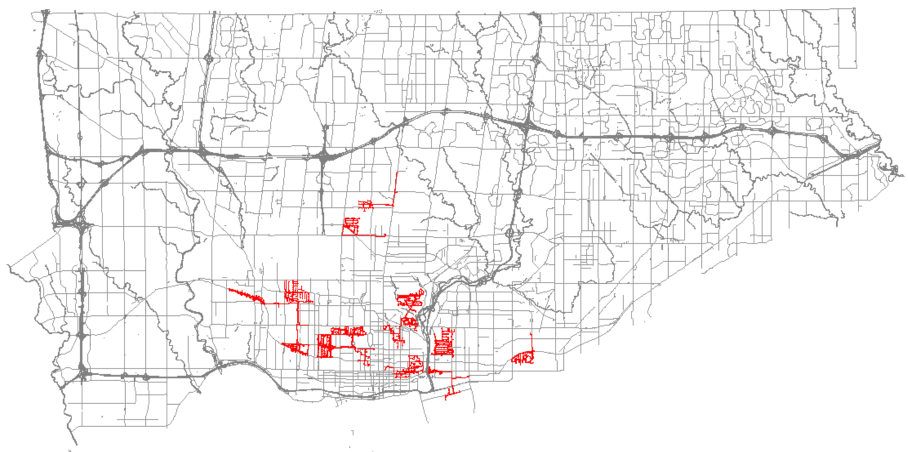


Figure 16: Map of Toronto with URD Feeders

The URD has three distinct feeder sections: (i) a main-loop; (ii) sub-loops; and (iii) branch circuits (or sub-sub-loops). Figure 17 below provides a simplified example of the configuration of a downtown URD feeder. The main loop is fed by the main feeder or standby feeder from the stations and interconnects the 600A switching vaults supplying an area, allowing for the isolation of the sub-loops and branch circuits in the event of a fault. The sub-loops start at the 600A switching vaults on the load side and end at the 200A switching vaults, where the branch circuits split off in multiple directions. URD transformers are connected to the primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

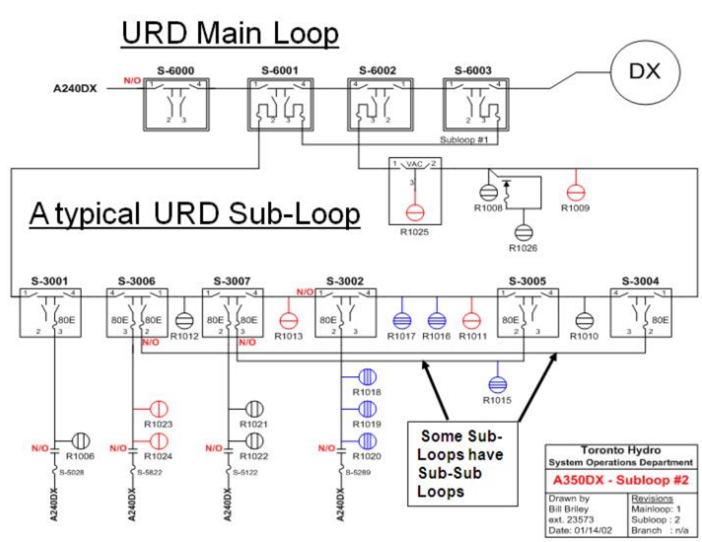


Figure 17: Typical URD Feeder Configuration

The reliability performance of URD system have been relatively stable over the last 5 years as shown in Figure 18 and Figure 19. Defective equipment was the largest contributor to annual customer reliability representing about 70 percent and 80 percent of CI and CHI, respectively. Targeted renewal of URD assets is required to support a stable reliability trend (i.e. maintain reliability performance).

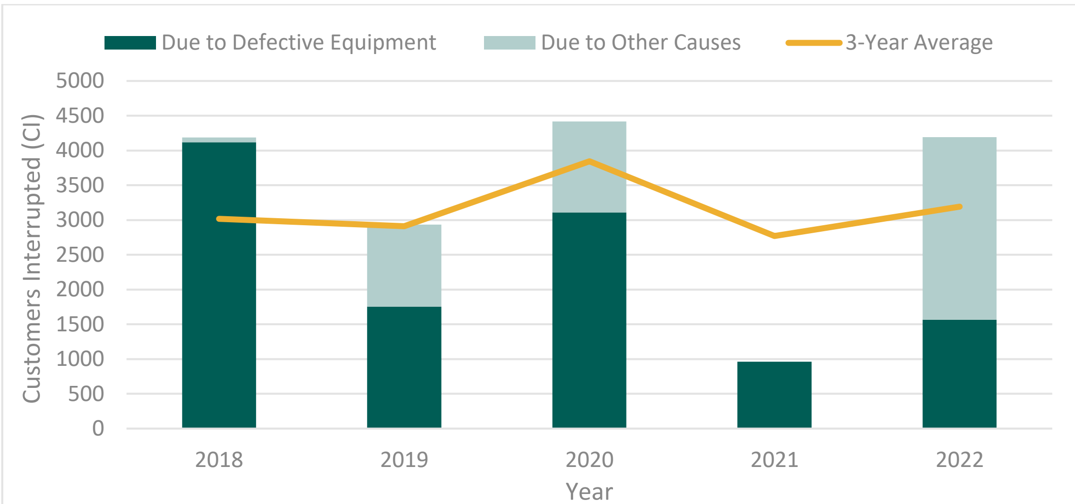


Figure 18: Customers Interrupted — URD System

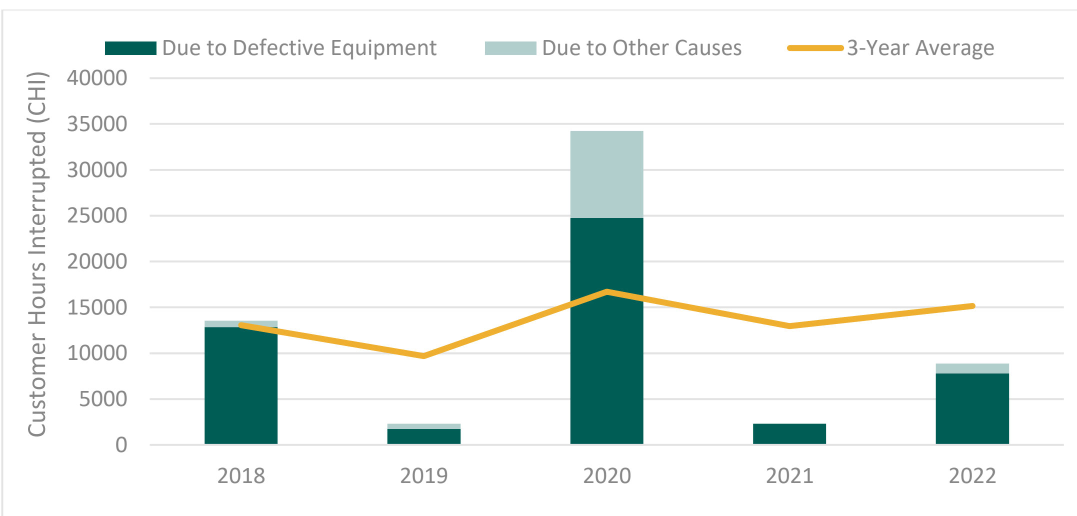


Figure 19: Customer Hours Interrupted — URD System

Figure 20 below compares the average CAIDI of URD system with 13.8 kV underground radial system over the last 5 years.[15] As can be seen from the figure, the average time to restore service in URD is

[15] Customer Average Interruption Duration Index

higher than underground radial system. This is mainly due to the fact that determining the source of an outage in the URD system can be time consuming due to the complex set-up of loops. The design of the URD includes FCIs, which help find the locations of faults in this complicated configuration so that customers can be restored in a timely manner. Of note, the average outage duration in URD system are on slightly increasing trend over the last five years. This is due to the corrosive environment in the switching vaults, where most of these FCIs are located leading to mechanical failure, and associated incorrect readings from the FCIs while fault locating.

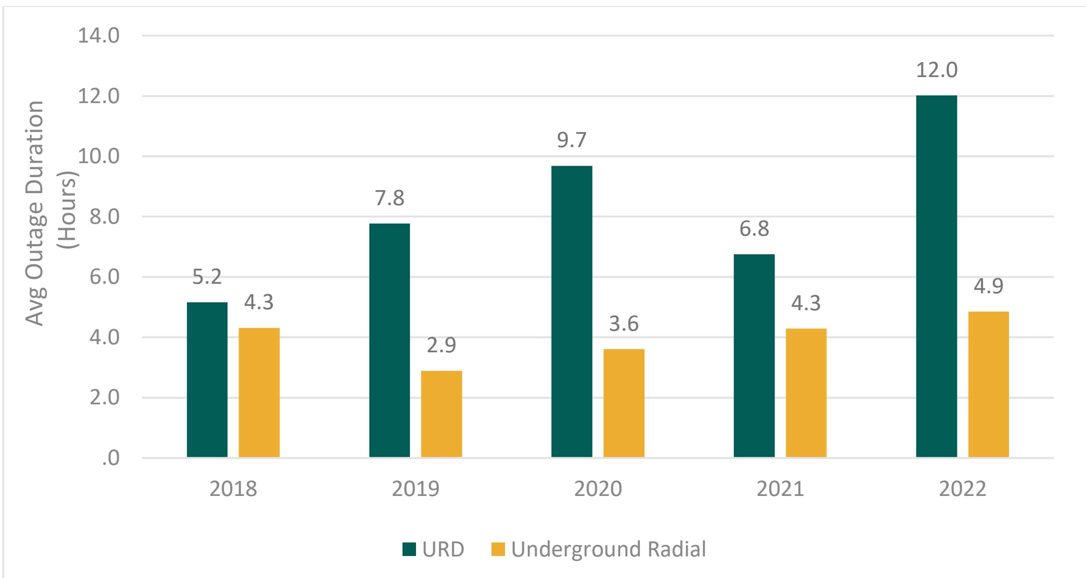


Figure 20: Average Outage Duration – URD vs Underground Radial System

Maintenance and inspection of the URD vaults are performed twice a year, one inspection for the civil condition and the other for the electrical condition. As part of this work, the vaults are inspected to ensure the integrity of the electrical equipment, structure, and security. This includes a thermograph of all electrical assets, cleaning the entire vault and reporting any vaults that require follow-up repairs. The results of the inspections show that URD switching vault equipment tends to be in poor condition due to rust on the cabinet and corrosion on the connectors. Figures 21 and 22 below provide the URD electrical and civil inspections results, highlighting the most common types of deficiencies identified and found over the past three years (i.e. 2020 to 2022).

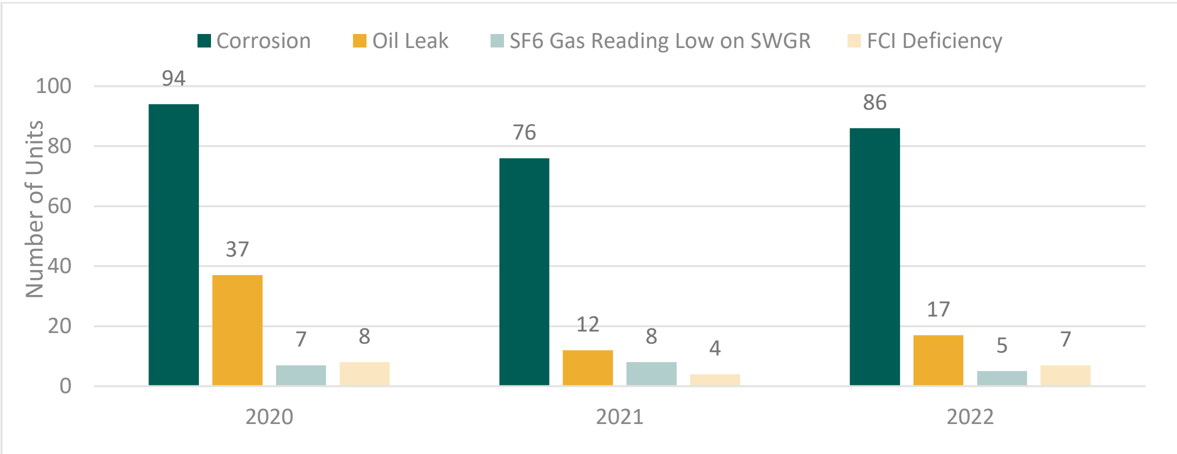


Figure 21: URD Electrical Deficiencies

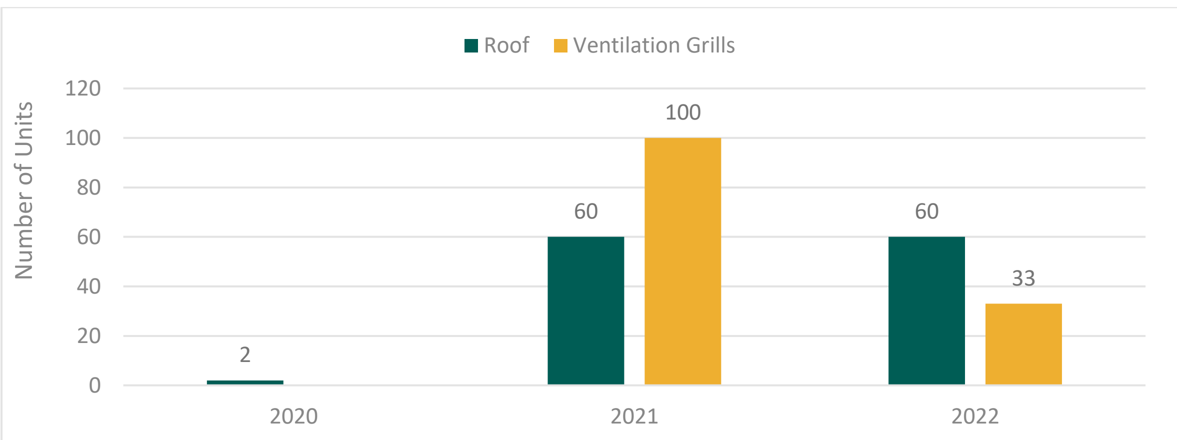


Figure 22: URD Civil Deficiencies

As per the URD electrical inspection data in Figure 21, the main issues are the recent rising number of deficient switchgears with low SF6 readings and malfunctioning FCIs, as well as corrosion of electrical equipment. As per the civil inspection data in Figure 22, URD civil deficiencies have been steadily increasing. These deficiencies increase the risk of failure of URD assets and as a result, the renewal process is driven by failure risk. The following sections describe the state of three main assets of the URD system: URD vault roofs, URD switches (including FCIs), and URD transformers while considering the above-mentioned deficiencies.

1. URD Vault Roof

Civil conditions of URD vaults deteriorate over time due to exposure to harsh environments as a result of severe weather, salt, or road construction. Some commonly found structural deficiencies caused by asset aging and environmental factors are exposed roof and wall rebar, corroded I-beams and cracked roof and walls. Such deterioration includes corrosion, spalling of concrete, and cover rusting which pose a potential safety hazard for the public and field crews. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations. This degradation of the URD vaults increases the failure risk of the assets within it. Illustrative examples of the aforementioned types of roof cracks are shown in Figure 23 and Figure 24 below.

Figure 23: URD Vault with Deficient Roof

Figure 24: URD Vault Deficient Roof Temporarily Repaired with Asphalt

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once during the life of the vault. Figure 25 below shows the age distribution of URD vaults. The majority of vault roofs of the URD vaults have reached or passed their useful life, and as such are considered for rebuild.

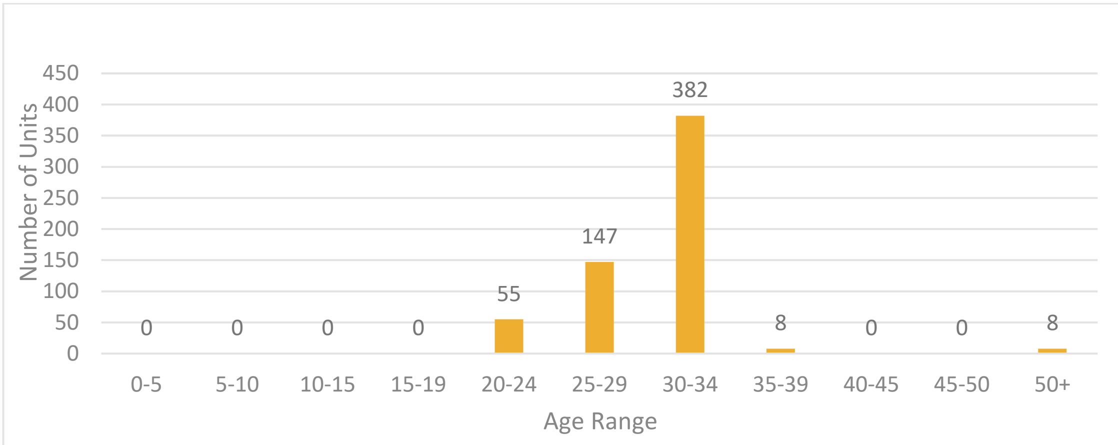


Figure 25: URD Vaults Age Distribution

Figure 26 presents the HI distribution (current and 2029 forecast) of the URD vaults. At the end of 2022, 8 of the URD vaults exhibit at least material deterioration (HI4/HI5 condition). The HI4/HI5 volume is forecasted to grow to 13 in 2029 without investment. It is important to note that the ACA model is a measure of the health of the entire vault asset, and that even vaults in HI1 or HI2 condition may have roof deterioration that needs to be addressed. To alleviate the risks posed by deteriorated vault roofs, Toronto Hydro plans to address 4 URD vault roofs between 2025 and 2029.

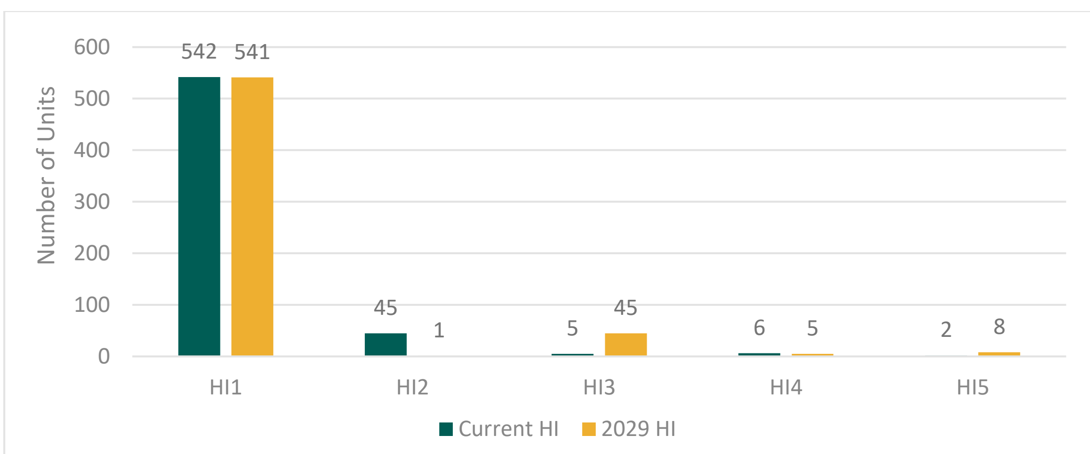


Figure 26: URD Vaults HI Distribution (Actual and 2029 Forecast)

Given the deficiencies being identified, Toronto Hydro is developing a new roof design that minimizes the amount of dirt, debris, and water that accumulate directly on electrical equipment. The new design will be similar to the compact radial distribution ("CRD") underground vault, which typically supply small retail, apartment, and commercial office buildings. In addition, the new design will improve safety by reducing the potential of tripping incidents, and create a larger opening for the replacement of electrical equipment. When rebuilding a vault roof, the electrical equipment will be assessed and upgraded to the latest standards if existing equipment is in poor condition or obsolete.

2. URD Switches

Switches used in URD are submersible, 200A and 600A, SF6-insulated switches which are operable from above grade. SF6 load break switches are designed and constructed to provide safe and reliable switching. Using SF6 for insulation and arc interruption eliminates space, weight and maintenance costs. The switch provides improved interrupting and open gap performance, while at the same time eliminating most hazards associated with vacuum or oil filled equipment. In the URD system, the switches are mounted on stands close to the vault wall for ease of operation, cabling, and space utilization.

As of the end of 2022, these switches are deteriorating in condition. A large portion do not have stainless steel enclosures and are experiencing gas leakage inherent to the former design of the bolted viewing window, as shown in Figure 27 below.

Figure 27: Example of a SF6 Switch with a "Low SF6" Reading

Due to the design and equipment specification of URD 200A and 600A switching vaults, they do not contain an available heat source, such as a transformer, that would promote air circulation. As a result, non-stainless steel switching equipment installed in those vaults are experiencing accelerated corrosion due to exposure to stagnant moisture. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations and supports or support beams. An example of a corroded support beam can be seen in Figure 28.

Figure 28: Example of Switch Supports that have rusted

The 200A SF6 switches are used to switch load as part of the sub-loop system. They also support 80E SF6 power fuses, which are used for the protection of branch circuits in the URD and are no longer manufactured. As such, there are limited 80E power fuses in Toronto Hydro inventory. A picture of the 80E power fuse is provided in Figure 29. In this regard, the switches are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are manufactured or available. Replacement of both the fuse and switchgear is required to provide the adequate protection for branch circuits.

Figure 29: 80E Power Fuse

Figure 30 presents the HI distribution (current and 2029 forecast) of the URD submersible switches. At the end of 2022, five of the URD submersible switches were exhibiting at least material deterioration (HI4/HI5 condition) and this is forecasted to grow to eight in 2029 without investment. To reduce the risks posed by deteriorated and obsolete submersible switches, Toronto Hydro plans to address four units between 2025 and 2029.

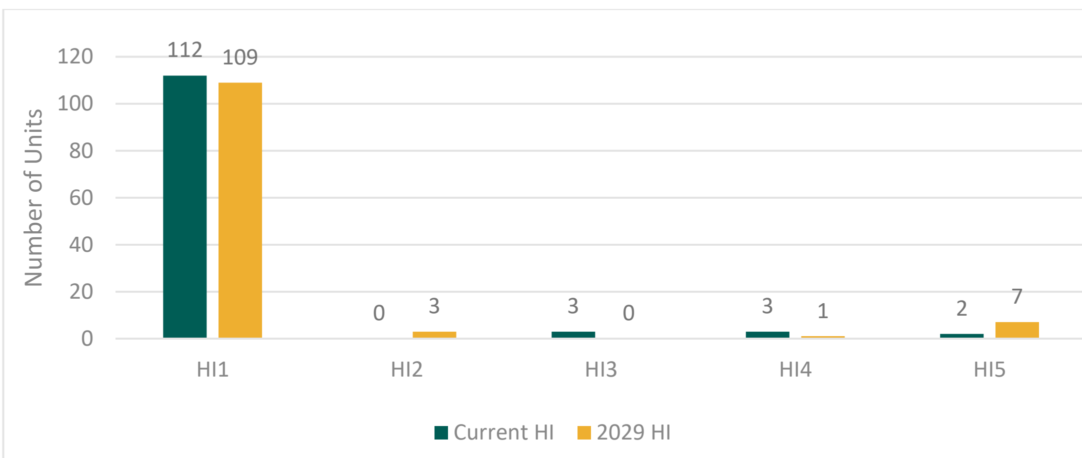


Figure 30: URD Submersible Switches HI distribution (Actual and 2029 Forecast)

In addition, several FCIs used in the URD system and manufactured as recently as 2017 are showing severe signs of corrosion. Some of the units failed to reset upon normal current restoration, giving misleading indications. Recent investigation showed broken internal wiring caused by corrosion and corroded current transformer (“CT”) laminations due to water ingress (See Figure 31 below)

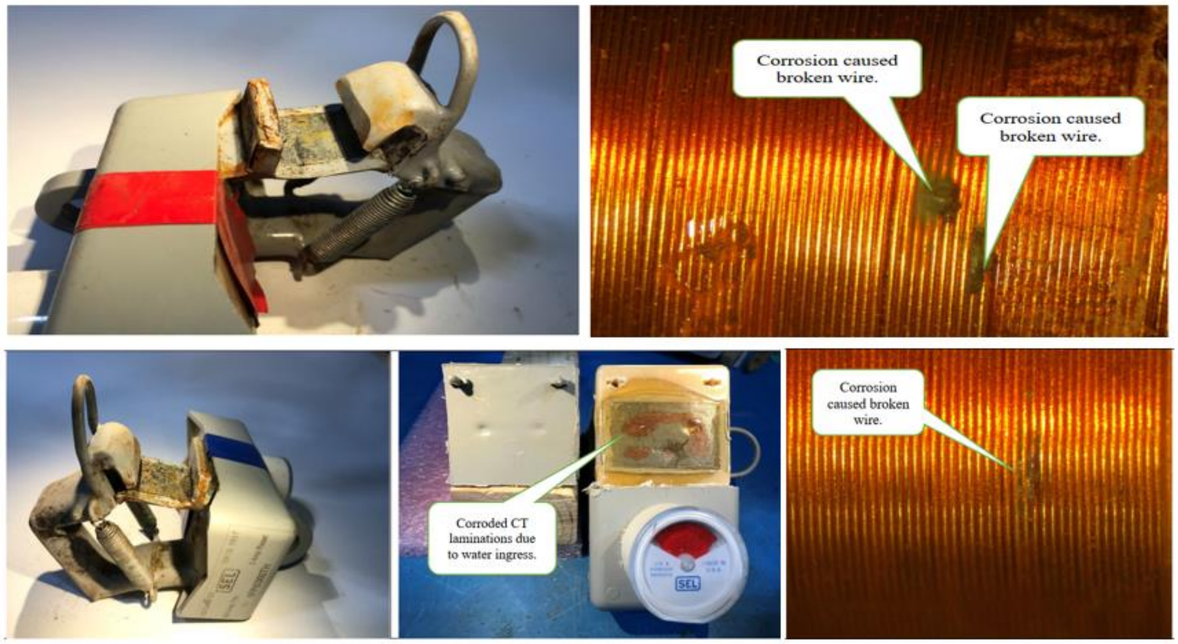


Figure 31: Teardown of the FCI units revealed water ingress caused corrosion in the CT resulting in broken wires

Given malfunctioning FCI is a contributing factor to long duration outages on the URD system, over 2025-2029 Toronto Hydro plans to replace 375 deteriorating and obsolete FCIs with the latest standards, targeting URD feeders with poor reliability performance.

3. URD Transformers

The main type of transformers used in the URD system are submersible transformers in URD vaults. The standard rating for a single phase URD transformer is 167 kVA while the three phase URD transformers range from 150 kVA to 750 kVA. URD transformers are connected to primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

URD transformers are exposed to harsh environments causing deterioration, with moisture being the most destructive element as it can lead to corrosion (see Figure 32). Corrosion of the transformer tank can lead to oil leaks into the environment and low transformer oil levels, which can lead to catastrophic failure. This presents a safety risk to the public and Toronto Hydro employees, in addition to reliability and environmental impacts.

Figure 32: Examples of URD Transformers Exhibiting Corrosion on Lids and Oil Leaks

Figure 33 shows the current and forecast (without investment) HI distribution of Toronto Hydro's URD transformers. As of the end of 2022, 12 URD transformers exhibit at least material deterioration (i.e. HI4 and HI5) and, without investment, this number is expected to increase to 92 by the end of 2029. In order to mitigate the expected increase in environmental, safety, and reliability risk of this asset population, Toronto Hydro plans to replace 17 URD transformers over 2025-2029.

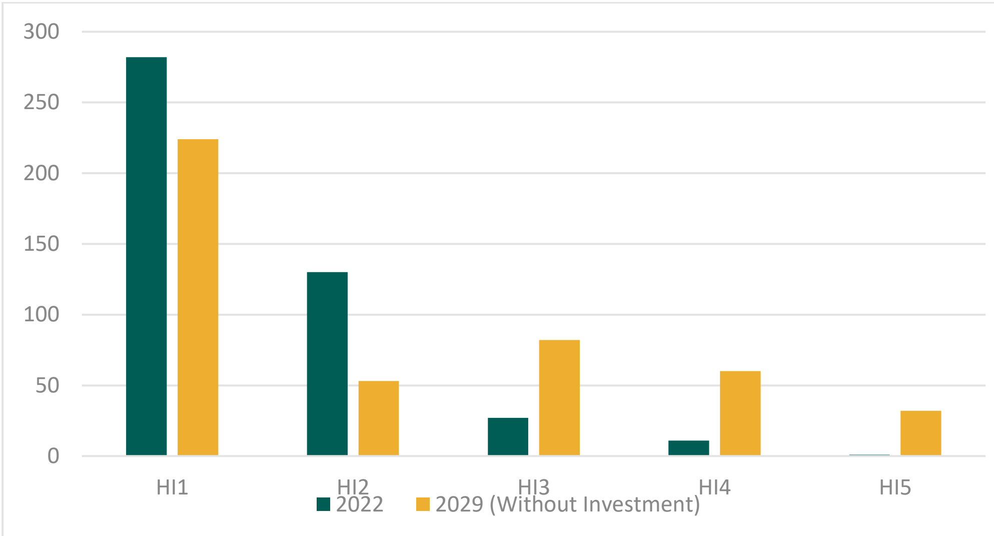


Figure 33: URD Transformer Asset Condition as of 2022 and 2029 (without investment)

As the URD vaults, transformers, and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. Toronto Hydro will replace the roof vaults with a newer design that reduces the dirt, debris, and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, the utility will replace electrical equipment such as transformers or switches within the vault with the equivalent latest standard. Toronto Hydro will also replace submersible with the new generation of SF6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet. Finally, the utility will replace FCIs prone to malfunctioning with new FCIs to speed up the outage restoration process.

E6.3.3.4 Underground Switchgear Renewal

The Underground Switchgear segment is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets have shown high reliability but have now become obsolete or pose a risk to the public. This segment aims to reduce failure and safety risks associated with legacy underground switchgear (see Figure 33) that are obsolete, past their useful life, in poor condition, and prone to failure. Failure can occur due to various factors such as age or repeated use over time, which results in breakage or failure to operate.

Figure 34: Example of Legacy Switchgear

In the 1960s and 1970s Toronto Hydro installed large transformers with underground switchgear in customer-owned vaults. Toronto Hydro owns this equipment, which feeds apartment buildings, educational facilities, and community centres. This underground switchgear is air insulated and used to provide primary supply to transformer vaults from two incoming primary feeders (one normal and one standby). Toronto Hydro has stopped installing this type of switchgear and considers them to be functionally obsolete equipment designs as they are no longer produced or supported by the manufacturer. The existing switchgear population is aging and becoming harder to maintain as spare parts for equipment repairs are not available, making it a challenge for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts precludes long term maintenance as a viable option to extend the service life of these assets.

As of 2023, there are 484 underground switchgear installed in the system. Figure 35 shows the current (2022) and forecast (2029, without investment) ACA for this asset group. The data indicates that six underground switchgear are categorized as having HI4/HI5 conditions and will require replacement in the near-term. While this is a relatively small number of assets (about one percent of these switchgear) with at least material deterioration, this is expected to grow significantly to 89 units (18 percent) by the end of 2029 without investment.

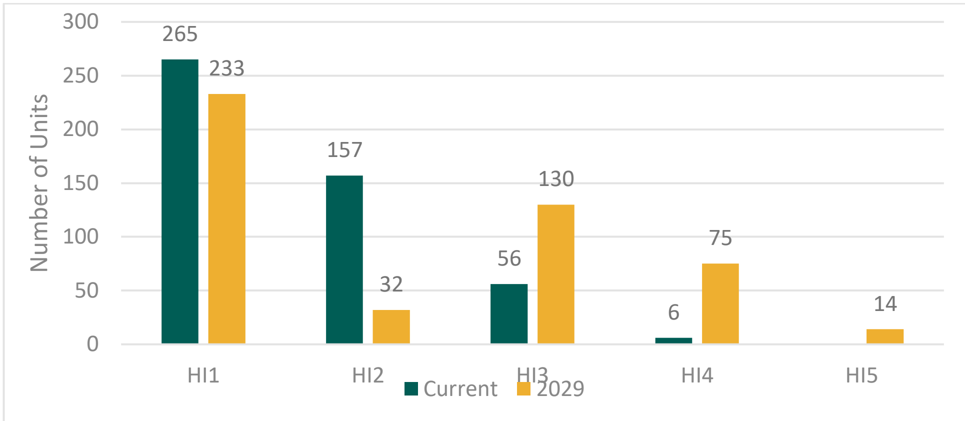


Figure 35: Underground Switchgear ACA distribution

Over the past five years from 2018-2022 work requests related to legacy switchgear have risen from 75 in 2018 to 257 in 2022. While much of this increase is due to the lowest priority work requests (P4), which require monitoring to ensure the issue does not worsen, higher priority work requests (PI and P2) have also been higher in recent years, as shown in Figure 36 below.

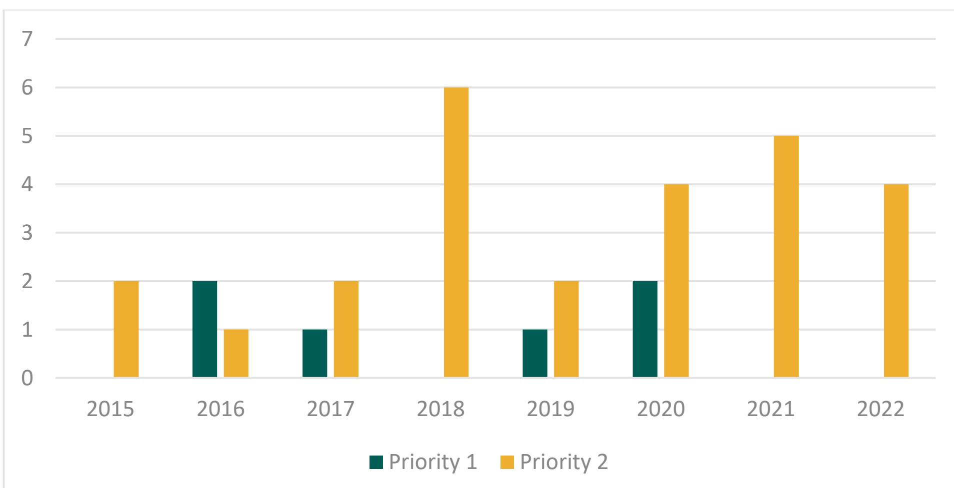


Figure 36: Underground Switchgear related Work Requests (High priority requests)

In the event where switching is required to isolate a customer or move the customer from one feeder to its standby, failed or defective legacy switchgear units may not operate as intended. This failure will result in either the delay of planned work until the switchgear is repaired or, in the event of a failure of the normal feeder, the customer will be without power for a prolonged duration as the switches are not useable. Customers supplied from the transformer vault with underground switchgear will be affected with the longest outage, but other customers on the feeder will be impacted as well due to the additional time required to isolate the faulted switchgear.

Failing legacy switchgear assets can potentially put the safety of customers and Toronto Hydro employees at risk. The inherent safety risk of switches not properly opening or failing to close entirely create an arc safety risk. Although no arc safety incidents have yet to be reported, as these switchgear age and further work request desk issues are recorded, the likelihood of having an arc safety incident will increase. Some of these legacy underground switchgears are non-submersible and could be damaged by water ingress into the vault as recorded by two incidents in 2018 and 2019. Since 2017, there have been three incidents related to underground switchgear failure, with the worst incident resulting in over 10 hours of interruption on average per customer. Even though the frequency of these events is low, the impact can be long duration outages for all customers on the feeder. Toronto Hydro plans to replace 20 of these switchgear over 2025-2029 to mitigate these risks.

E6.3.4 Expenditure Plan

To address the needs of the underground assets in downtown Toronto, Toronto Hydro plans to invest $165.1 million over the 2025-2029 period. Each segment entails a unique investment strategy as discussed in the following subsections.

Table 5: Forecast Program Costs ($ Millions)[16]

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1
URD Renewal	-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8
Underground Switchgear Renewal	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7
Total	**7.1**	**8.5**	**20.2**	**29.4**	**15.3**	**20.5**	**26.0**	**32.3**	**41.3**	**45.0**

[16] Note that costs associated with former streetlighting assets are embedded in the costs of the segments.

E6.3.4.1 Underground Cable Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $36.9 million in the Underground Cable Renewal segment as shown is Table 6, which is approximately $52.8 million lower than planned in the 2020-2024 DSP. Over the 2025-2029 period, Toronto Hydro plans to spend $61.0 million to replace legacy PILC and AILC cable, an increase of 65 percent over the 2020-2024 period.

Table 6: Underground Cable Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5

Over 2020-2022, Toronto Hydro spent $18.5 million and installed 14 circuit-km of primary TRXLPE cable in duct and approximately 6 circuit-km of secondary cable in duct, as shown in Table 7. Toronto Hydro plans to invest another $18.4 million in 2023-2024 to install 16 circuit-km of primary TRXLPE cable in duct and 1.4 circuit-km of secondary XLPE cable in duct. The expected total PILC cable replacement for the 2020-2024 period exceeds the 2020-2024 DSP planned volume of 27 circuit-km by 3 km, while the expected AILC cable replacement is 44 circuit-km less than the planned volume of 53 circuit-km.

The variance in AILC cable is attributed to the prioritization of PILC over AILC cable replacement and a lack of colocation between the two. Toronto Hydro plans projects according to the priority of primary PILC feeder cables and any AILC cable along the route are identified for replacement at the same time for efficiency. This segment was a new segment for the 2020-2024 period and as project areas were selected, the utility discovered that there was lower than expected colocation between AILC cable and high priority primary PILC cables. AILC cable is mainly present in the secondary network system and some segments of AILC cable are being replaced through the Network System Renewal program.[17] Toronto Hydro has adjusted the forecast AILC volume for 2025-2029 based on this experience it has gained over the 2020-2024 period.

[17] See Exhibit 2B, Section E6.4.

The total expected 2020-2024 spending for this segment of $36.9 million is less than half of the $89.7 million forecast in the 2020-2024 DSP. Toronto Hydro reduced the segment budget significantly to support meeting the utility's capital funding limits,[18] but was still able to meet and slightly exceed the planned PILC cable replacement volume. The unit cost for PILC cable replacement over 2020-2022 was lower than the estimated unit cost in the 2020-2024 DSP due to the following:

- Civil work is costly and challenging to execute due to congested underground infrastructure, the City of Toronto's own infrastructure renewal plans, and other development projects. Therefore, as projects are developed from high level scoping to project development to detailed design, Toronto Hydro evaluates alternate options such as utilizing available civil infrastructure on the other side of the road or another parallel road to defer costly civil work and ensure the executability of projects. Over 2020-2022, Toronto Hydro successfully leveraged these alternatives to limit the amount of civil work needed and keep the average unit costs below the original estimates from the 2020-2024 DSP.
- Projects requiring more civil work require longer lead-up time due to additional design and permitting requirements. Since this was a new segment in 2020, the majority of the projects that the utility has been able to execute so far have not had significant civil work as they could move more quickly to the execution stage. Therefore, the historical unit costs for from 2020-2022 are not expected to be fully representative of future costs as they include mostly electrical costs only. As more projects are executed in future years, the average unit cost is expected to be closer to the estimated unit cost in the 2020-2024 DSP.

Toronto Hydro plans to invest $61 million in 2025-2029 to replace 35 circuit-km of primary PILC cable in duct, 9.3 circuit-km of secondary AILC cable in duct and 5 kilometers of fiber optic cable.

Table 7: 2020-2029 Volumes (Actual/Bridge/Forecast) – Underground Cable Renewal

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PILC Cable (km)	0.8	2.9	10.4	12.4	3.8	5.2	6.4	6.8	7.5	9.0
AILC Cable (km)	0.0	1.6	4.3	1.4	0.0	1.4	1.7	1.8	2.0	2.4
Fiber Optic Cable (km)	0.0	0.0	0.0	0.0	0.0	5.0[1]				

[18] See Exhibit 2B, Section E4 for more details.

Note 1: Toronto Hydro plans to install a total of 5 km of fiber optic cable units over the 5 year period and will determine the yearly allocation during project scoping based on infrastructure criticality and accessibility, feeder loading, and the feasibility of connecting to the existing fiber network.

The Underground System Renewal – Downtown program prioritizes at-risk cable segments based on historical failures, the number of splices on feeders, age, and customer base. Toronto Hydro will use this in conjunction with complementary cable testing data to validate the volume of cable replacement required. This is considered to be a best practice in the industry and is used by utilities such as Consolidated Edison (ConEd) in New York City for their PILC cable replacement program.[19] For cables where inspection and maintenance information is limited, studies have shown that this method is condition driven and a reliable alternative to traditional methods for asset ranking based on asset age, failure history, or asset 'health indices' .[20]

Toronto Hydro has determined that approximately 4.6 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2025-2029 period. This 4.6 percent amounts to 44 circuit-km of PILC, and will trigger replacement of approximately 5.3 percent of the existing AILC population (9.3 circuit-km) connected downstream of PILC cable.

Toronto Hydro plans to install 5 km of fiber optic cables to enable on line cable monitoring in locations where no fiber optic cables currently exist. It should be noted that fiber optic cable network already exists on some sections of the downtown core and could be used to deploy online cable monitoring where applicable. Toronto Hydro will select locations to expand this fiber optic cable network based on the existing fiber optic network, the criticality of the route (e.g. number of feeders and key account customers served by the feeders), the difficulty in accessing or maintaining cables on those sections (e.g. rail crossings or under water tunnels), and colocation with a feeder identified for underground cable renewal work in the 2025-2029 plan.

Based on actual and forecast costs for 2020-2024 projects, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.2 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2025-2029 segment cost of $61 million.

[19] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, "online", http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf

[20] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

E6.3.4.2 Cable Chamber Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro expects to invest a total of $40.1 million in the Cable Chamber Renewal segment as shown is Table 8 below, which is approximately $11 million higher than forecast in the 2020-2024 DSP. The higher spending is primarily due to a higher volume of lid replacement and higher than estimated unit costs.

Over 2025-2029, Toronto Hydro plans to increase spending in this segment to $96.5 million to address 199 cable chambers at risk of failure and 2,800 potentially hazardous cable chamber lids, as shown in Tables 8 and 9 below.

Table 8: Cable Chamber Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1

Over the 2020-2022 period, Toronto Hydro spent $16.4 million to rebuild 10 cable chambers, complete 15 roof rebuilds, and replace 459 cable chamber lids with energy mitigation lids. Toronto Hydro plans to invest $23.7 million in 2023-2024 to replace 830 cable chamber lids, rebuild 22 roofs and 17 cable chambers, and complete 2 cable chamber abandonments. The total number of cable chambers addressed (excluding lids) is less than the proposed volumes in the 2020-2024 DSP as the average cost for cable chamber rebuilds, lid replacements and roof rebuilds has significantly increased compared to what was originally estimated in 2018.

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, it had no actual costs or experience executing this work proactively to base its estimates on, as it was a new segment starting in 2020. Therefore, the estimates did not fully account for certain factors such as the need to replace obsolete PILC and AILC cables, the requirement to take outages to do full rebuilds in certain circumstances, and the full impact of working in congested areas downtow and requirements from the City that some of this work be performed only during weekends and at night. These factors were further exacerbated by the COVID-19 pandemic and unusually high escalation in labour and material costs over this period.

Table 9: Cable Chamber Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Chamber	4	1	5	9	8	3	4	9	15	15
Cable Chamber Roof	7	3	5	19	3	14	26	28	30	30
Cable Chamber Abandonment	0	0	0	1	1	3	5	5	6	6
Cable Chamber Lid	105	162	192	650	180	400	450	550	700	700

Toronto Hydro's spending plan for this segment for the 2025-2029 period includes the following breakdown:

- 2,800 cable chamber lid replacement (approximately $14,350 per unit)
- 46 cable chamber rebuilds (approximately $450,000 a unit)
- 128 cable chamber roof rebuilds (approximately $80,000 each unit)
- 25 cable chamber abandonments (approximately $25,000 each unit).

Toronto Hydro has applied these unit costs to planned unit volumes to develop the 2025-2029 segment cost of $96.5 million. Unit costs are based on recent experience planning and executing cable chamber renewal projects.

Reconstructing a cable chamber requires breaking into or reconstructing portions of duct bank. As such, the cable chamber renewal segment includes the cost of reconstructing a portion of a duct bank along with cable replacement within the cable chamber. Required electrical work within a cable chamber, road or sidewalk repair, and road restoration are also incorporated into the cost. In developing the cable chamber renewal segment costs for 2025-2029, Toronto Hydro now assumes that outages are not required for cable chamber roof rebuilds, but are required for full rebuilds of cable chamber when there are non-standard cables in the chamber which needs to be changed. If the cable chamber does not meet standard requirements, the civil structure will be rebuilt to meet current standards.

Based on inspection records, 592 cable chambers have been identified to be in HI4 and HI5 condition and another 521 are projected to become HI4 or HI5 by 2029 without investment. Toronto Hydro is increasing its investment in this segment to address 199 cable chambers and mitigate this increasing backlog and the associated safety and reliability risk. Cable chamber rebuilds are highly complex projects, as they require not only civil resources but also electrical resources, permits from the City to dig into streets, management of the high volume of downtown vehicular and pedestrian traffic, and extensive coordination between various stakeholders. The new chamber has to conform to current standards and the size may have to be enlarged to minimize congestion of the cables inside and to accommodate more cables for future needs. In light of these needs, a cable chamber rebuild requires a detailed design. The proposed pace is moderate and accounts for the above challenges and resourcing considerations, as well as the length of time civil deficiencies can be managed before renewal is required

Toronto Hydro mainly prioritizes cable chambers based on the condition of the civil infrastructure as well as the types of customers and thermal loading of feeders. As Toronto Hydro has gained experience planning and executing these projects and has a better understanding of the required costs, it expects to be able to ramp up the pace of investment over 2025-2029. Also based on recent project experience, when planning a cable chamber, the utility will also inspect adjacent chambers in the area and consider any intervention in tandem such that all required work can be completed together. Toronto Hydro will also review the location for possible challenges, such as interference with TTC or other utility infrastructure.

E6.3.4.3 URD Renewal

The URD Renewal segment aims to replace end-of-life and obsolete URD assets that contribute to the deterioration of system reliability. These assets include: vaults, switches, and transformers that form part of the URD system. In addition, THESL plans to install FCIs on select URD feeders that will be prioritized based on reliability performance in order to mitigate the risk of long duration outages.

Table 10 below provides the year over year breakdown of URD Renewal investment including the actuals (2020-2022), bridge (2023-2024), and forecast (2025-2029).

Table 10: URD Renewal 2025-2029 Segment Costs ($ Millions) — URD Renewal

Actual			Bridge		Forecast				
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8

The total (actual and bridge) 2020-2024 expenditure of $3.5 million is slightly higher than the 2020-2024 DSP forecast of $3.3 million. Over the 2020-2022 period, Toronto Hydro spent approximately

$1 million and completed three roofs rebuilds and replaced two submersible switches and one URD transformer. Toronto Hydro plans to spend approximately $2.6 million over 2023-2024 to renew seven submersible switches, five transformers, and seven vault roofs.

Table 11: URD Assets Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
URD Submersible Switches	0	0	2	1	6	9
URD Transformers	0	0	1	0	5	6
URD Vault Roof	0	1	2	1	6	10

Toronto Hydro spent slightly more than planned, while completing fewer roof rebuilds and switch replacements (but additional transformer replacements) due to the following reasons:

- Installation of new 200A switch was a pilot initiative, which also required a new vault roof design. As such, there was a significant learning curve in completing designs and obtaining approvals. Pilot projects related to new technologies are susceptible to risk due to uncertainties. The COVID-19 pandemic added another layer of complexity, for example increasing the lead time of the new 200A submersible switches, which affected project execution and timing.
- The unit cost of URD assets was higher than the originally estimated cost, which were estimated using comparable standards as Toronto Hydro had no previous experience with this work and the actual standards had yet to be developed at the time. This was further exacerbated by externally-driven escalations of labour and material costs over the 2020-2022 period. The higher units costs contributed to fewer units completed in order to limit overspending.

Toronto Hydro plans to invest $4.8 million over 2025-2029 to support maintaining URD system reliability and long-term asset risk levels. With this level of funding, the utility estimates that it can renew four submersible switches, 17 transformers, and four vault roofs, and replace 375 old and obsolete FCIs with the latest standard, as shown in Table 12. However, the number and mix of assets addressed are subject to change as Toronto Hydro prioritizes projects and develops detailed scopes. For example, the utility will prioritize projects based on the condition of civil roofs, as deficient roofs pose an immediate risk to the public and employees. Assets such as URD switches and transformers within these vaults will be replaced on an as-needed basis according to the latest available inspection records.

Table 12: URD Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
URD Submersible Switches	1	1	1	1	0	**4**
URD Transformers	3	3	3	3	5	**17**
URD Vaults (Roof Rebuild)	2	1	1	0	0	**4**
FCIs	0	100	100	100	75	**375**

E6.3.4.4 Underground Switchgear Renewal Expenditure Plan

The underground switchgear renewal segment aims to replace end-of-life and obsolete underground switchgear assets that contribute to the deterioration of system reliability and pose safety risks. Table 13 below provides Toronto Hydro's annual forecast 2025-2029 expenditures to address the critical underlying issues of the underground switchgear assets in Toronto downtown.

Table 13: Underground Switchgear Renewal 2020-2029 Segment Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Switchgear	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7

There are no historical expenditures associated with this program. Toronto Hydro plans to spend $0.1 million in 2024 for design work related to projects to be executed starting in 2025. Over 2025-2029, the utility proposes investing $2.9 million to replace four switchgears per year. The forecast costs are based on bottom-up estimates (i.e. labour and material requirements) to install a compact radial design standard, which is used in new building vaults.

Switchgear replacement projects may also include replacing transformers depending on the condition of the existing transformer and the feasibility of connecting it to the new standard switchgear. The planned pacing is the practical rate that Toronto Hydro is realistically able to achieve given available resources, while benefiting customers through reduced interruptions and safety risks. The utility will prioritize switchgear based on the condition (current and future HI), inspection and maintenance history, and historical reliability.

Table 14: Underground Switchgear Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
Underground Switches	4	4	4	4	4	**20**

E6.3.5 Options Analysis

E6.3.5.1 Underground Cable Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would replace 3.2 percent of PILC cable (31.7 circuit km of 985 km) and 1.7 percent of AILC cable (3 km of 176 km) cables. This reduced pace is aligned with a 35-year timeline for removal of all remaining PILC and AILC cable (when considering cable replacement work done in other programs).

As mentioned in section 3.1, PILC and AILC cables are becoming obsolete across the industry due to environmental, health, and safety concerns. The longer it takes to remove these legacy cables from the distribution system, the greater the risk that Toronto Hydro will not be able to properly maintain the remaining population due to a lack of manufacturer support. In addition, approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old and these aged cables are showing signs of deterioration. Cable splices as a result of reactive replacement of failed PILC and AILC cable, which also increase failure risk, will also increase if these cables are not proactively replaced. This will negatively impact reliability for customers in the downtown area and drive up reactive spending.

Under this option, Toronto Hydro would also not invest in any installation of fiber optic cable, limiting the implementation of on line cable monitoring in the downtown area and the associated benefits described in section E6.3.3.1.

2. Option 2 (Selected Option): Sustainment pacing of PILC and AILC Cables

Under this option, Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) and install 5 km of fiber optic cable over 2025-2029. This option will replace PILC cable at a pace aligned with a 30-year timeline to remove all PILC cable when considering the cable replacement work done in other programs.

Under this option, Toronto Hydro would mitigate the failure risk on the downtown distribution system and maintain reliability. As mentioned above, non-uniformity (i.e. cable splicing) increases the risk of failure. Therefore, by replacing the highest risk cables, the utility will increase the uniformity of cable types in the system (i.e. by replacing the non-uniform cable with XLPE cable), which will help maintain reliability on the system. The installation of fiber optic cable would enable Toronto Hydro to extend the reliability and asset optimization benefits from online cable monitoring.

In addition to maintaining reliability, this option will reduce the risk of oil leakage from the insulation on PILC cables and therefore reduce the need for service interruptions on customers to address these leaks.

3. Option 3: Accelerated Replacement of all PILC and AILC cable over 25 years

Under this option, Toronto Hydro would replace PILC and AILC cables in its distribution system at a pace aligned with a 25-year timeline for full removal when considering the cable replacement work done in other programs.

This would allow the utility to more proactively address the environmental and safety issues associated with the continued use of PILC and AILC cables. It would also mitigate the risks associated with a single supplier (i.e. procurement risk). Furthermore, it would address reliability risks and provide downtown customers with improved reliability.

However, this option is estimated to cost approximately 1.5 times the cost of the proposed plan and does not represent a reasonable balance between price and other outcomes such as reliability. It would also require that additional resources be allocated to this segment, which may be a challenge given other priorities.

E6.3.5.2 Cable Chamber Renewal

1. Option 1: Reduced Pace (Lid Replacements)

Under this option, Toronto Hydro would proactively address 199 cable chambers that represent approximately 35 percent of the projected HI4 and HI5 population by 2029 (without investment), which is consistent with Option 2. Toronto Hydro considers this to be the lowest reasonable number of cable chambers that should be addressed over 2025-2029 to address safety and reliability risks. It is also a pace that realistically accounts for the challenges in planning and executing this work and the required resources.

However, under this option Toronto Hydro would only replace 1,400 chamber lids at risk of ejection (approximately 12 percent of the population) with energy mitigation lids. Toronto Hydro finds that the safety risk due to the significant number of potentially hazardous cable chamber lids that would remain in the system is too high and therefore this option is not recommended.

2. Option 2 (Selected Option): Sustainment Pace

Similar to Option 1, under this option Toronto Hydro plans to proactively address 199 cable chambers that represents approximately 35 percent of projected HI4 and HI5 population by 2029 (without investment). The utility considers this to be the minimum number of cable chambers that should be addressed to sustainably manage the asset population and mitigate the growing backlog of deteriorated structures and associated safety and reliability risk. The proposed pace is moderate and accounts for the challenges and resourcing considerations associated with this work as well as the length of time civil deficiencies can be managed before renewal is required.

However, compared to Option 1, the proposed plan also includes the replacement of twice as many (2,800) potentially hazardous cable chamber lids (approximately 25 percent of the population) with energy mitigation lids. This would address all of the high risk locations and most of those considered a medium risk for lid ejection, mitigating the safety risk to a much more acceptable level.

3. Option 3: Accelerated Pace

Under this option, Toronto Hydro would address all at-risk (i.e. HI4/HI5) cable chambers and replace 5,000 cable chamber lids with energy mitigating lids. Although, this would significantly reduce safety and reliability risks associated with deteriorated cable chambers, this pace would require significantly more spending and resources and could pose execution challenges. Road moratoriums within Toronto's downtown core may further challenge Toronto Hydro's ability to execute the work at an accelerated pace in the short- to medium-term. Toronto Hydro finds that this is not an appropriate balance of benefits and costs and would potentially be infeasible to execute and therefore this option is not recommended.

E6.3.5.3 URD Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would address select deteriorating URD assets at a reduced pace to manage deterioration. The investments would target the following:

- Replace approximately 25 percent of URD switches and 15 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 25 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 150 FCIs on the URD feeders with the most outages.

Although this option would be cheaper and mitigate asset failure risk to some extent, it could still negatively impact URD reliability performance and increase safety [and environmental] risk and the deterioration of asset health. Reactive replacement and rebuild of URD assets would likely increase. Deteriorated civil condition of URD vault roofs can potentially compromise the electrical equipment within the vault and also increase the safety risk for Toronto Hydro employees when they enter the vault. Failing or deteriorated switches and transformers can release harmful environmental contaminants such as oil and SF6 gas and pose safety risks, in addition to impacting reliability performance. Finally, faulty FCIs can lead to prolonged outages, which customers have indicated a are a priority.

2. Option 2: (Selected Option) Sustainment Pace

Under this option, Toronto Hydro plans to proactively rebuild URD vault roofs and replace deteriorating and obsolete submersible switches and poor condition transformer at a modest pace. The investments would target the following (subject to detailed prioritization and planning of projects):

- Replace approximately 50 percent of URD switches and 40 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 30 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 375 FCIs on the URD feeders with the most outages.

As URD vaults, transformers, and switches deteriorate, they need to be addressed proactively to reduce failure risk and mitigate the associated. Under this option, Toronto Hydro would invest a moderate incremental amount over Option 1 that better supports maintaining the reliability, environmental, and safety risks and longer-term sustainability of the URD system. This option is recommended because it provides the best balance between risk and cost compared to the other options.

3. Option 3: Accelerated Replacement of URD Assets

Under this option, Toronto Hydro would replace a larger population of the obsolete 200A switches and install FCIs across all URD feeders. Toronto Hydro anticipates that while this pacing option would better address reliability risk in the URD system, this strategy would also require significantly higher spending and does not represent an appropriate balance of price and reliability aligned with customer priorities. Therefore, this option is not recommended.

E6.3.5.4 Underground Switchgear Renewal

1. Option 1: Reactive Replacement Approach

This option entails continuing to operate the legacy underground switchgear units as is and replacing them only reactively upon failure. Failure rates have slowly increased in recent years and would likely continue to increase, which poses a challenge as there is no longer manufacturer support and spare parts are not available. Accordingly, maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

2. Option 2 (Selected Option): Replacement of Underground Switchgear at Proposed Pace

Toronto Hydro's plan addresses safety risks associated with deteriorating legacy switchgear units and would improve reliability and safety of the system. The utility expects the replacement of legacy switchgear units to avoid some of the customer impacts and costs associated with in-service asset failures, such as customer interruptions and emergency repairs and replacement. At the proposed pace of 4 units per year, 20 of the 89 units forecast to have at least material deterioration by 2029 would be replaced and their associated safety and reliability risks addressed. Those remaining units not replaced by 2029 or ones not replaced in a timely manner will continue to pose a higher risk of failure until they are replaced. However, this is the recommended option as it is expected to result in an acceptable, but not ideal, reduction in the number of at-risk units at a reasonable level of spending.

3. Option 2: Replacement of Underground Switchgear at Accelerated Pace

Under this option Toronto Hydro would replace legacy switchgear units at an accelerated rate of 8 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating legacy switchgear units. At this pace, Toronto Hydro would replace almost half of the 85 units projected to have at least material deterioration by 2029. This would reduce the number of legacy switchgear units operating at elevated risk of failure, however, it would also cost twice as much as Option 2 and is therefore not the recommended option.

E6.3.6 Execution Risks & Mitigation

A key execution risk affecting the Underground System Renewal – Downtown program is external dependencies. In the downtown area, coordination with third parties (e.g. City of Toronto, TTC) has been an on-going requirement. Toronto Hydro invests substantial efforts to ensure effective inter-agency coordination.

Toronto Hydro ensures that optimal routes are chosen based on criteria, such as the avoidance of busy intersections and paths where utilities reside. Often, projects require construction of new civil assets such as duct banks or cable chambers. It is expected that these projects may be delayed without effective coordination. To mitigate risks, these projects will be planned well in advance.

Additionally, road moratoriums have the potential to delay projects in the downtown core. To mitigate this risk, Toronto Hydro will plan and schedule work accordingly.

Underground Cable Renewal will prioritize at-risk cables dynamically as testing data, and cable replacement data become available. This means cables that are deemed low-risk one year, may be high risk in another year. As such, dynamic planning will be required, targeting the highest risk assets based on the best available information, i.e. feeders that are statistically more likely to fail. However, this approach may result in disruptions to project scheduling and planning. Efforts will be made well in advance to coordinate multiple projects at the same time so projects are deferred or advanced accordingly.

The successful roll out of new URD assets, including URD submersible switches will depend on the results of a field trial that is currently underway. The plan is to incorporate lesson learned and make any changes before standardizing the product. In addition, since all URD assets are located in residential neighbourhoods in the downtown core, coordination with the relevant customers is critical. Toronto Hydro will abide by residential community by-laws such as noise levels placed by the City of Toronto and coordinate with all stakeholders as necessary.

There may be unforeseen conditions or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plant prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Finally, as has become evident over recent years, supply chain pressures and disruptions can drive up material costs and impact timelines. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.4 Network System Renewal

E6.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 116.1	**2025-2029 Cost ($M):** 123.4
Segments: Network Unit Renewal; Network Vault Renewal; Network Circuit Reconfiguration	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Financial Performance	

The Network System Renewal program (the "Program") addresses deteriorating and functionally obsolete underground network system assets serving primarily small to medium-sized customers in the pre-amalgamation City of Toronto. These customers reside in the City's core and are often sensitive to outages.[1] For example, sensitive customers that are served by this part of the system include commercial businesses, GO Transit, and hospitals. The Program is designed to maintain reliability and mitigate public safety risks by: (1) replacing non-submersible and deteriorated network units, (2) replacing network vaults in deteriorated condition, and (3) reconfiguring and re-cabling sub-optimal grid networks.

The Program is grouped into the three (3) segments summarized below and is a continuation of the network renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan, with the exception of Legacy Network Equipment Renewal which was completed in the current rate period.[2]

- **Network Unit Renewal:** This is a continuation of planned replacement of network units at risk of failure. As network unit condition deteriorates, the risk of failure increases, and with it the likelihood of consequences such as lengthy customer outages and vault fires. This segment will target deteriorated units, predominantly non-submersible units. The non-submersible units are susceptible to water ingress and elevated failure risks even when in

[1] As discussed in Exhibit 2B Section D2.2.2, the underground network system is the most reliable configuration available among Toronto Hydro's distribution schemes, and is therefore an ideal option for customers who are sensitive to outages and concerned about reliability.

[2] EB-2018-0165, Exhibit 2B, Section E6.4. Over 2020-2024 Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB").

good condition. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index scores. Without intervention, the utility projects that 149 units will be materially deteriorated ("HI4") or at end-of-serviceable life ("HI5") by 2029 and that 50 percent of its network units will be at or beyond useful life by 2034. The utility plans to replace 130 network units between 2025 and 2029. This rate of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population. Toronto Hydro plans to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.

- **Network Vault Renewal:** This is a continuation of Toronto Hydro's efforts to rebuild or decommission poor condition network vaults. These civil structures were generally built in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Toronto Hydro must proactively address structurally deficient vaults in order to mitigate risks to public safety, employee safety, and system reliability, and to maintain the long-term viability of the distribution system. If the proposed work is not completed, the number of network vaults in HI4/HI5 condition is forecasted to increase from 91 to 137, or approximately 29 percent of the vault population, by 2029. During the 2025-2029 period, Toronto Hydro plans to eliminate immediate structural deficiencies of 38 high-risk vaults identified through the Asset Condition Assessment ("ACA") process as having at least material deterioration ("HI4"). Due to the complexity of this mostly downtown work, the rate of planned replacement is less than optimal. However, at the pace of renewal, Toronto Hydro will see a slight increase in the assets in material deterioration or end-of-serviceable-life (HI4 or HI5 condition by the end of 2029, relative to 2022.

- **Network Circuit Reconfiguration:** This is a continuation of Toronto Hydro's plan to mitigate the impact of multiple contingency failures on the network system. This segment involves reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. The result will be minimized customer interruptions, improved planning, modeling, and operational flexibility, and enhanced ability of the network system to operate under extreme events (e.g. multiple contingency outages). Toronto Hydro plans to reconfigure the parts of three secondary networks over the 2025-2029 rate period, an investment that is expected to deliver long-term reliability and resiliency benefits for network customers in the downtown area.

Toronto Hydro plans to invest $123.4 million in the Network System Renewal program over the 2025-2029 rate period, which is approximately a 6 percent increase over projected 2020-2024 spending on this Program (including forecasted inflation). This level of investment is necessary to maintain public and Toronto Hydro employee safety, and the service levels that downtown customers rely on and expect from the network system.

E6.4.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's Network Units Modernization measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Replacing 130 network units at highest risk of failure due to poor condition or vulnerability to flooding; ○ Eliminating structural deficiencies of 38 high-risk vaults that are placing enclosed equipment at risk; ○ Replacing older non-submersible or submersible network units with those equipped with sensors to monitor vault conditions and enable quicker response to adverse network conditions; ○ Reducing average restoration time during a full network outage by reconfiguring networks to support all or most of the load; ○ Reducing customer interruptions by a third during second contingency events, by reconfiguring networks to improve operability under multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by eliminating network units at high risk of failure and vulnerable to vault fires or oil spills.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's modernization and safety objectives by: ○ Minimizing the risk of catastrophic transformer failures by replacing network units most at risk due to deteriorated condition or exposure to higher-risk environmental factors; ○ Eliminating potential trip and falling debris hazards at 38 vaults with significant civil deterioration.

Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Reducing the need to dispatch crews in multiple contingency scenarios by reconfiguring the network to support all or most of the network load; and ○ Supporting reduction in summer peak reading inspections by enabling monitoring and control of network units (see Network Condition Monitoring and Control program).[3]

E6.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Safety, Environmental Risk, Reliability, System Efficiency

Toronto Hydro's network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive downtown customers. The Network System Renewal program aims to replace network assets at risk of failure due to deteriorating conditions. The failure of these assets negatively impacts reliability and the effective operation of the network system and potentially increases the risk to public safety and Toronto Hydro's crews.

Toronto Hydro's low voltage secondary network distribution system includes the following assets:

- Network Units that consist of primary switches, network transformers, and secondary network protectors, which are assembled into a single unit;
- Network Vaults, which contain the aforementioned equipment; and
- Secondary Cables, which connect the aforementioned equipment and provide service connections to customers.

The Network System Renewal program is needed to replace those assets that are at risk of failure in order to mitigate the associated safety, environmental, and reliability risks and to maintain the service levels that downtown customers rely on and expect from the network system.

[3] Exhibit 2B, Section E7.3

E6.4.3.1 Network Unit Renewal

The Network Unit Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 rate application. This segment aims to reduce failure risks associated with network units that are obsolete, in poor condition, and prone to failure. The goal of the segment is to replace the most at-risk units, as indicated by the above criteria, before they fail and potentially cause safety or environmental incidents such as fires or oil leaks.

Although replacements are prioritized based on condition, the network units that are replaced are typically legacy "non-submersible" designs characterized by "ventilated" (see Figure 1) or "semi-dust-tight" protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. These units also typically contain electro-mechanical relays that are not capable of remote condition monitoring or control. They are replaced with units that are of a submersible design (see Figure 1), containing microprocessor relays, and are capable of meeting the requirements for Toronto Hydro's Network Condition Monitoring and Control program.

Figure 1: Snapshot of a Ventilated Network Unit (L) and Submersible Network Unit (R). The black protector is of a submersible design, which prevents water ingress.

1. Failure Risk and System Efficiency

Two main failure modes can impact a network unit. The first is flooding of the network vault that may damage the protector mechanism causing the unit to short, or fail to operate. The second is an internal transformer failure that is typically caused by low oil, moisture ingress, or age-related insulation deterioration. To maintain network system reliability, network units need to be both routinely maintained and proactively replaced when they are at an increased risk of failing. Maintenance of network units is summarized in Exhibit 4, Tab 2, Schedule 2. Not replacing deteriorated network units in a timely manner can lead to equipment failures, and in turn cause interruptions to customers, oil leaks of 1,000 litres and more, and potential vault fires that may impact (including by expelling smoke) busy arterial roads in the downtown core of Toronto.

Replacing deteriorated or non-submersible units located in areas prone to flooding with submersible protectors that feature watertight cases can help address failure risks. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index information. Toronto Hydro has over 1,900 network units of which roughly 30 percent have non-submersible protectors, which are legacy designs used prior to the installation of the first submersible units in 2003. As a result, virtually all units older than 20 years are ventilated or semi-dust-tight.

Figure 2 shows the current age distribution of submersible and non-submersible network units. With a useful life 35 years, as of the end of 2022, approximately 22 percent of the network unit population is at or beyond useful life. Without any capital investment, this number is projected to increase to 27 percent by 2029 and to 56 percent by the end of 2034. Not investing at a steady pace of asset renewal will not only increase reliability risks on the distribution system but also increase the need to ramp investments in the future and associated complexity involved in replacing a large number of units over a short period. This could result in more outages and higher safety risks due to failure.

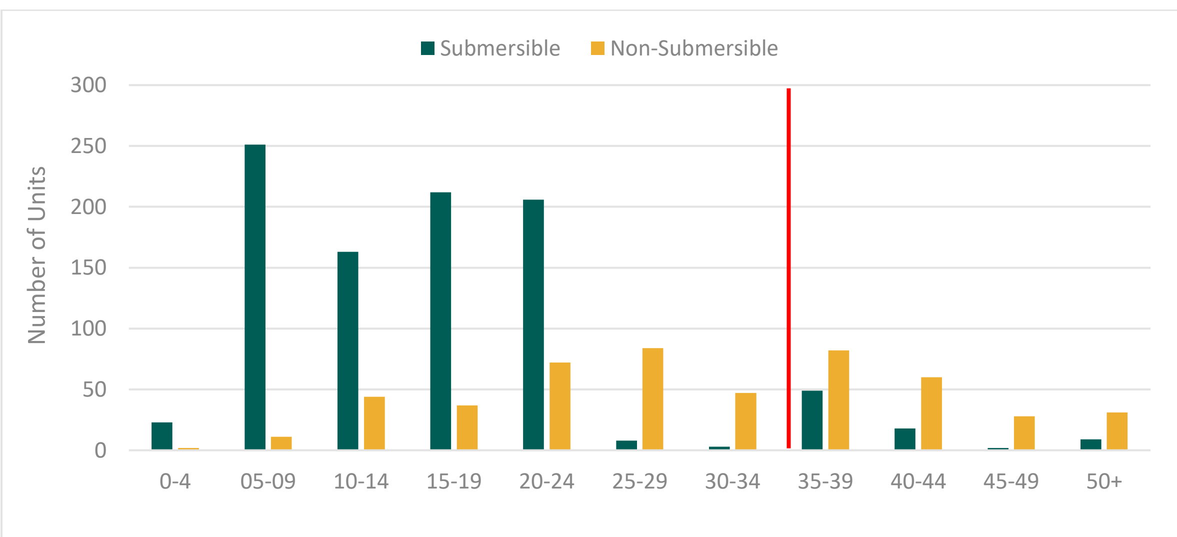


Figure 2: Network Unit Age Demographics

Based on 2022 ACA data, the current and estimated 2029 health index distribution (without proposed work) for network units is shown in Figure 3. HI4 means "material deterioration" and HI5 means "end of serviceable life". It is expected that HI4/HI5 numbers will increase from 43 units (in 2022) to 149 units in 2029. The network unit renewal segment plans to replace 130 units at an average rate of about 26 per year over the 2025-2029 rate period to address deteriorating and high failure risk units.

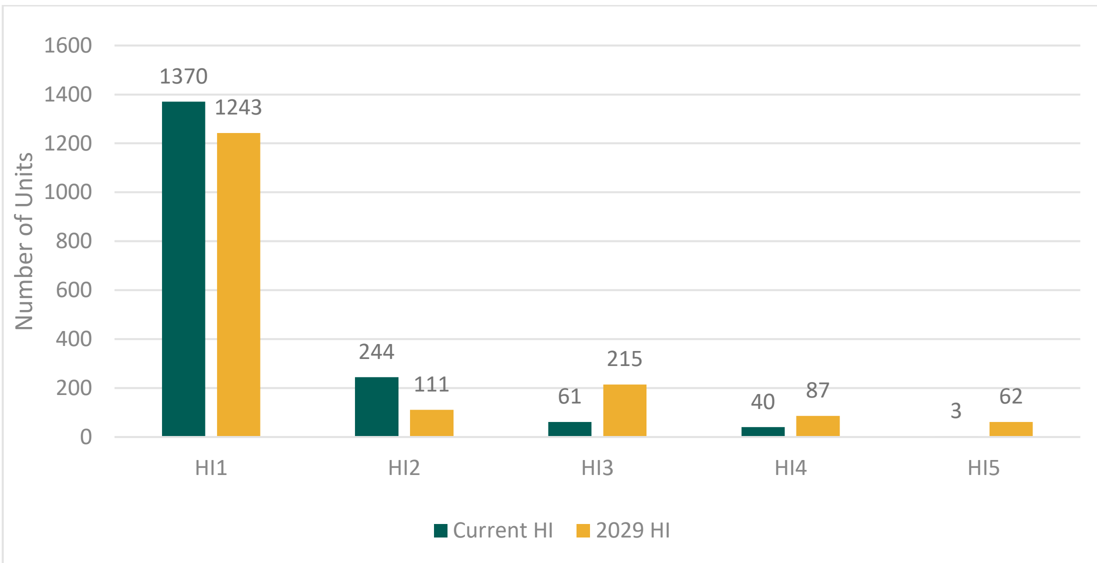


Figure 3: Network Transformers Condition Demographics – Current and Forecasted HI (without Renewal)

2. Safety and Environment

Failure of deteriorated network units can result in both safety and environmental incidents. From a safety perspective, catastrophic failures may cause damage to surrounding property and put the public at risk of injury, especially given that network vaults are typically installed under sidewalks with significant pedestrian traffic. From an environmental perspective, corroded and deteriorated network units may result in oil leaking within a vault, and the possibility of oil escaping through vault drainage systems into the environment. Between 2020 and 2022, Toronto Hydro has experienced 82 oil leaks from network transformers. As network transformers typically contain more than 1,000 litres of oil, oil leaks have the potential to lead to serious environmental consequences. Figure 4 shows the distribution of the 82 network transformer oil leaks experienced by volume of oil leaked.

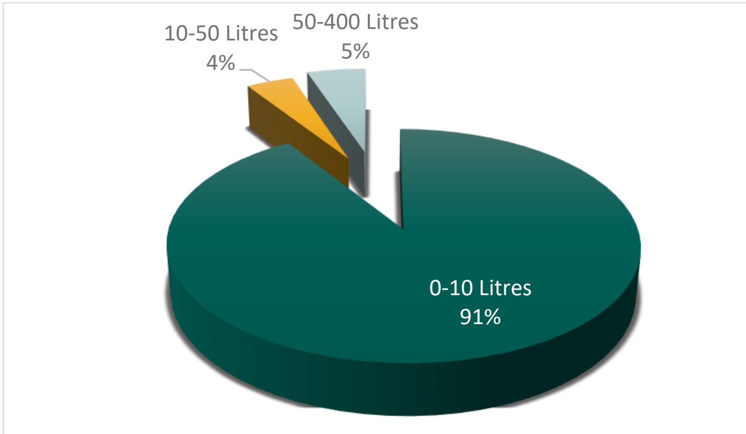


Figure 4: Network Transformer Oil Leaks (2020-2022)

Oil leaks are mitigated by replacing deteriorated units and units operating in environments which place them at elevated risk.

E6.4.3.2 Network Vault Renewal

The Network Vault Renewal segment is a continuation of the network vault rebuild and decommissioning activities detailed in Toronto Hydro's 2020-2024 rate application. Many network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in Toronto's busy downtown core. Today, these assets have many critical structural issues and Toronto Hydro plans to address the worst of them based on condition data. The aim of this segment is to reduce failure risks resulting from vault structural deficiencies that can negatively impact the reliability and effective operation of the utility's distribution system as well as safety risks to the public and Toronto Hydro crews.

3. Failure Risk

Vault structural deficiencies are mainly caused by old age and exposure to adverse environmental factors. Currently, Toronto Hydro has about 470 network vaults, predominantly in the downtown core, supplying the network system. Figure 5 shows the age distribution of all network vaults with reference to the useful life of both the overall vault (60 years) and the roof (25 years).

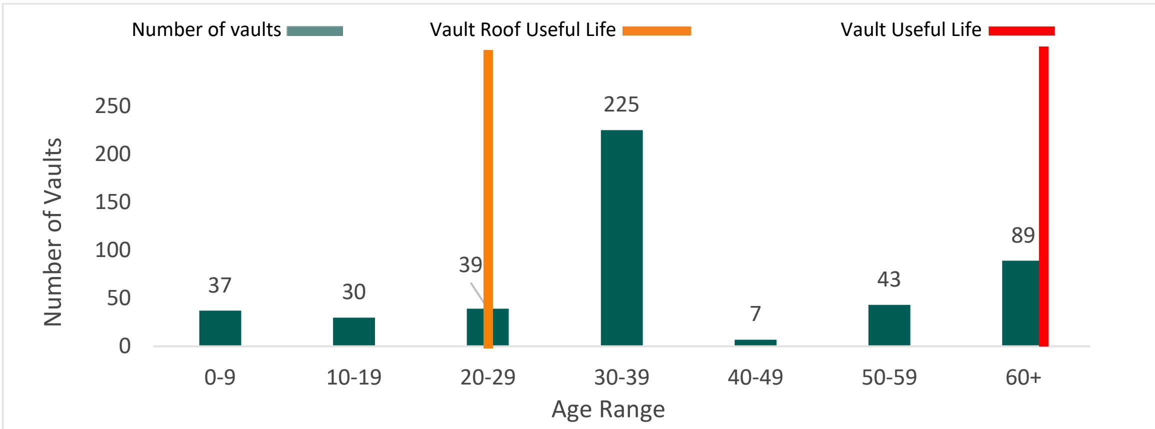


Figure 5: Age Distribution of Network Vaults

The vast majority of vault roofs have reached the end of their expected useful life of 25 years. Additionally, over 28 percent of the vault civil structures will reach the end of their expected useful lifespan (of 60 years) within 10 years. ACA results show that some vaults are deteriorating at an accelerated pace and require repairs even though they have yet to reach their expected lifespan. The increased use of de-icing salts in recent years is contributing to this accelerated aging. Figure 6 shows that as at the end of 2022, 91 (19 percent) of Toronto Hydro-owned network vaults exhibit at least material deterioration (HI4/HI5) and are clear candidates for work under this renewal segment. This number is forecasted to grow to 137 (29 percent) in 2029 if the proposed work is not completed. In addition to the 23 network vaults planned for renewal in 2023-2024, Toronto Hydro plans to address 38 network vaults between 2025 and 2029 to alleviate the risks posed by deteriorating vaults.

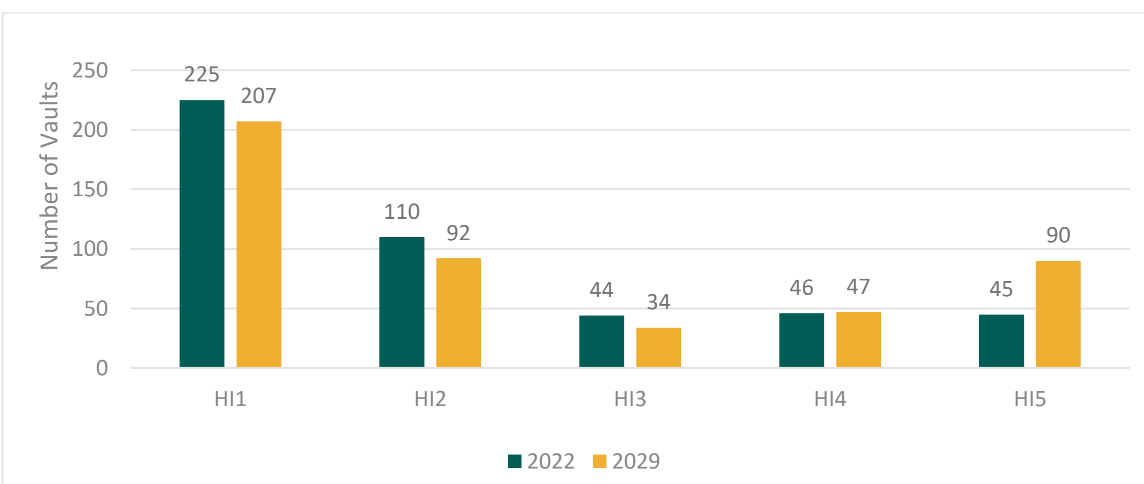


Figure 6: Current, 2025 and 2029 Health Scores for TH-owned Network Vaults

Some commonly found structural deficiencies caused by asset aging and environmental factors are described in Table 4.

Table 4: Vault Structural Deficiencies and Impacts

Deficiency	Impact
Exposed Roof Rebar	Failure risk that can lead to roof collapse, damage to equipment and safety hazard to the public and Toronto Hydro crews.
Exposed Wall Rebar	Failure risk may result in collapse of the vault walls, potentially leading to damaged equipment, costly repairs, safety hazards, and power outages.
Corroded I-Beams	Failure risk due to age and environmental factors can lead to collapse of the roof structure.
Cracked Roof	Exposes electrical equipment to leaking water and accelerated corrosion which may result in catastrophic failure.
Cracked Walls and Floor	Increases risk of failure causing flooding and damage to equipment which may result in large outage.

Examples of these deficiencies are shown in Figure 7, Figure 8, Figure 9, and Figure 10 below.

Figure 7: Roof and Wall with Exposed Rebar

Figure 8: Corroded I-beams

Figure 9: Cracked Roof and Wall

Figure 10: Deteriorated Vault Floor

4. Reliability and System Efficiency

As discussed above, there are several failure modes and deficiencies that may lead to structural failure within a vault. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets within the vaults, thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids and up to 3,000 customers (50 MVA) for the large network grids in the downtown core. The outage can last from several hours to a few days, depending on the location, the severity of the fault and, the network distribution system being impacted.

If a vault roof is not replaced on time, removing it later to replace faulty equipment can cause it to collapse, making it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to the customers fed by that feeder. To maintain reliable service to interruption-sensitive downtown customers, it is imperative that these assets be renewed before they fail.

5. Safety

Table 5 highlights different safety risks to the public and Toronto Hydro crews resulting from deteriorated network vaults. There are two main types of risks to the public. First, the risks of slips, trips, and falls stem from cracking and structural shifting of vault roof structures. Second, complete failure of roof elements can expose the public to energized electrical equipment.

Table 5: Safety Risk & Descriptions

Safety Risk	Description
Slips, Trips & Falls	A deteriorated vault roof may result in uneven grading on sidewalks or walkways and lead to slips, trips, or falls, which could cause injury to members of the public or Toronto Hydro crews.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of the vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The risk posed by cracking and structural shifting can be controlled by a maintenance program that patches or grinds down hazardous structural elements as needed. However, once a vault reaches the point where major structural deficiencies cannot be addressed by maintenance, three different options are available:

- **Decommissioning vaults** (see Figure 11) that are no longer needed as a result of load displacement. The typical cost to decommission a vault is approximately $150,000 to $180,000 and it takes approximately one month to perform the work;
- **Rebuilding the vault roofs** (see Figure 12) where severe structural deficiencies have been identified, but which are located on network vaults that are otherwise structurally sound. The typical cost of rebuilding a vault roof is up to approximately $360,000 and it can take approximately three months to perform the work;
- **Rebuilding entire vaults** (see Figure 13) that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned but require more extensive repairs beyond a vault roof replacement. The typical cost for

rebuilding a vault is up to approximately $1.8 million, which includes the average costs for both civil and electrical work. This work can take between 18 and 24 months to complete.

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best course of intervention for any given vault location.

Figure 11: In-Progress Vault Decommissioning

Figure 12: Temporary Roof during a Roof Rebuild

Figure 13: Completely Rebuilt Vault

For the 2025-2029 Network Vault Renewal segment, Toronto Hydro plans to address the immediate structural vault deficiencies of 38 high risk vaults identified through Toronto Hydro's ACA process as having at least material deterioration. In addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required.

E6.4.3.3 Network Circuit Reconfiguration

Toronto Hydro plans to reconfigure large network grids so that either: (i) sufficient grid flexibility is introduced to enable the sustainment of second contingency events; or (ii) sufficient customer loads are automatically dropped during second contingency events to allow the remainder of the grids to continue operating reliably.

A reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. The network grids targeted for reconfiguration between 2025 and 2029 have six feeders on average and an average of 30 MVA. This segment is a continuation of the work under the same program, as described in the 2020-2024 rate application. In a second contingency event, instead of losing all 30 MVA, the reconfigured networks would only lose about 10 MVA. This equates to a 67 percent reduction in interrupted load.

The Network Circuit Reconfiguration segment uses a number of different methods to address the problems and risks associated with multiple contingency events. The methods used depend on the configuration of the network and the requirements needed to reconfigure it into a robust system that supports second contingency. A single reconfiguration project may utilize multiple methods including:

- **Splitting grid into spot vaults:** This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events.
- **Splitting grid into enhanced mini-grids:** This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Upsizing transformers:** The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overload and would require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Changing primary feeder connections to network transformers:** This option improves diversity in the feeders supplying the network, thereby making it more resilient to multiple contingency events.

- **Reinforcing existing secondary network grid cabling:** This option ensures secondary cabling is not overloaded during multiple contingency events.

6. Failure Risk

Network Circuit Reconfiguration mitigates the impact of failures. The risk of network system outages has increased over time due to:

- **Evolving Operating Practices:** The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment so that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. However, a small number of transformer failures resulted in vault fires. The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which may leave insufficient remaining contingency capacity to sustain the network grid.
- **Multiple Contingency Events:** Operation of the network system under multiple contingency scenarios imposes challenging requirements on operating personnel. First, a network expert must analyze the grid to identify critical overload conditions and propose customer load reductions and necessary reactive tasks, all within restrictive time limits. If an expert is not immediately available at the control center, power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations.
- **Reach of the Secondary Network Distribution System:** The secondary network distribution system represents approximately 10-15 percent of downtown Toronto's peak load. Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread, including many radial supply loads on the same feeders. Often major portions of station switchgear, with up to about 50 MVA of customer load (equivalent to approximately 25,000 residential customers), must be interrupted following such events.

For a typical network with no more than six primary feeders, a widespread forced outage due to a second contingency event would cause about 30 MVA of load to be dropped for four hours to prevent equipment overload. In recent years, these events have occurred approximately once every three years. A reconfigured network grid should be able to sustain a second contingency incident without requiring the entire network to be dropped. This should typically result in a two-thirds reduction in interrupted load.

7. Reliability and System Efficiency

The network system in Toronto was designed for first contingency operation. Under any first contingency event, power system controllers do not need to take any action to ensure continued reliable supply to network customers. On the other hand, multiple contingency events would require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a network cascade failure. As previously mentioned, Network Circuit Reconfiguration enables a network to sustain a second contingency incident without requiring the entire network to be dropped. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement in terms of system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, isolation and repair of failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration is expected to reduce the workload required to stabilize the network and restore customers, allowing for restoration work to begin at the earliest opportunity, thereby minimizing the time required to restore the network to normal operation.

Table 6 below identifies the networks targeted for reconfiguration in the 2025-2029 rate period. Over 2025-2029, Toronto Hydro will complete reconfiguration for the parts of three networks that are carried over from the 2020-2024 and 2015-2019 rate periods. All networks targeted will be reconfigured after they have been updated with monitoring and control through the Network Condition Monitoring and Control program.[4] Through Network Condition Monitoring and Control alone, it is expected that around one-third of total network load will be preserved during second contingency events. A reconfigured network will typically preserve approximately two-thirds of the total load during these events (representing an additional one-third savings during second

[4] Exhibit 2B Section E7.3

contingency events on networks already updated with condition monitoring and control). The synergies between these two programs are expected to allow many customers to be sustained even during rare third contingency events.

Table 6: 2025-2029 Targeted Networks for Reconfiguration

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year
A-North Phase 2	9	22	15	2025
GD Phase 2	9	25	20	2026
CE-South South Ph2	8	16	7	2027

The networks to be reconfigured during this filing period represent around 10 percent of the major network system load. Multiple contingency events occur approximately once each year and the existing network system can successfully manage approximately two-thirds of these events.

8. Functional Obsolescence

The existing secondary grid network distribution system was initially designed for pure network loads and not the mixed network and radial loads that exist today. Network feeders are designed such that they can be highly loaded since loads are automatically redistributed across all other network feeders in case of an outage. However, because radial feeders cannot be loaded as highly, due to the need for them to pick up load during contingency scenarios affecting adjacent feeders, the overall utilization of a mixed feeder is reduced. Furthermore, because of the presence of radial loads on a mixed feeder, the capacity to operate the network under multiple contingencies becomes insufficient. Enhancement of secondary network grid flexibility is necessary to adapt to this new reality.

E6.4.4 Expenditure Plan

To address the critical underlying issues of the network assets in downtown Toronto, the utility plans to invest $123.4 million in the Network System Renewal program during the 2025-2029 rate period. Table 7 below provides Toronto Hydro’s annual Historical Years (2020-2022), Bridge Years (2023-2024) and forecasted 2025-2029 expenditures for each of the Program segments.

Table 7: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Network Equipment Renewal (ATS & RPB)[5]	1.9	1.3	0.8	0.3	-	-	-	-	-	-
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-
Total	**15.0**	**22.1**	**32.0**	**28.6**	**18.4**	**13.7**	**14.8**	**30.5**	**31.2**	**33.2**

E6.4.4.1 Network Unit Renewal

Table 8 below provides the year over year breakdown of Network Unit Renewal investment spending including the actual historical spending from 2020-2022, the bridge years from 2023-2024, and forecasts for 2025-2029.

Table 8: Historical and Proposed Investment Spending ($ Millions) — Network Unit Renewal

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2

Toronto Hydro invested $26.9 million in network unit renewal between 2020 and 2022, replacing 82 deteriorated and non-submersible units as shown in Table 9. An additional 84 network units were replaced reactively. The utility plans to invest a total of $53.2 million by the end of 2024 to proactively replace an additional 95 network units over 2023 and 2024 to minimize failure risks.

Table 9: Network Units Replaced — Actual/Bridge vs Planned

	Actual	Bridge	Total

[5] Over 2020-2024, Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining ATSs and RPBs.

	2020	2021	2022	2023	2024	2020-2024
Actual / Planned	20	30	32	44	51	177

The higher segment cost, while completing fewer units was mainly driven by:

- Increased amount of legacy cable removal and upgrade work completed while changing out network units. Many of the targeted units are in vaults where Asbestos-Insultated Lead-Covered ("AILC") secondary cable containing asbestos and lead are present and/or have primary Paper-Insutated Lead-Covered ("PILC") cable that terminates at the network units. While the Underground System Renewal – Downtown targets the proactive replacement of AILC and PILC cables, Toronto Hydro replaces these legacy cables as part of network unit renewal projects to improve work execution efficiency. [6]
- Similarly, where appropriate, Toronto Hydro spent more than expected to install certain Network Condition Monitoring & Control ("NCMC") equipment and perform the necessary wiring while replacing network units to improve overall efficiency.
- Material cost increases driven by raw material price increases.
- Project execution challenges including constraints related to moratoriums, coordination issues between stakeholders, and scheduling feeder outages resulted in delay in work execution for some projects. In some instances, civil work was needed to be completed prior to unit renewals.

Over the 2025-2029 rate period, Toronto Hydro plans to spend a total of approximately $51.2 million on this segment to replace deteriorating and high failure risk units. The utility forecasts 149 network units will have at least material deterioration (HI4/HI5) by 2029 and that 27 percent of the total population is expected to be at or beyond useful life. Of these, Toronto Hydro plans to replace 130; an average rate of 26 units replaced per year between 2025 and 2029. While the pace of renewal over the DSP period is lower relative to 2020-2024 pacing, Toronto Hydro forecasts that the proposed pace of renewal is required to mitigate further increases in risk. In addition, THESL has incorporated the results of customer engagement to pace the Network Unit renewal investment.

[6] Exhibit 2B, Section E6.3.

The replacement of units with the highest failure risk is projected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. In addition, newer units will be equipped with new features (e.g. monitoring capabilities to enable faster response to developing problems and submersible protectors).

To minimize costs and use resources efficiently, Network Unit Renewal projects will be combined with other Network System Renewal projects, where possible. In addition, work on at-risk units fed from a common feeder will be planned to be executed in the same year. The asset condition data collected from inspections will be leveraged to prioritize the high failure risk units within the asset class. Severely deteriorated and non-submersible units located in areas prone to flooding will be given the highest priority. Projects can be reprioritized if an urgent need is discovered.

E6.4.4.2 Network Vault Renewal

The Network Vault Renewal segment rebuilds vaults and vault roofs. From 2020 to 2022, Toronto Hydro spent $30.9 million to rehabilitate (or decommission) 20 vaults. Toronto Hydro expects to spend $19.0 million to address 23 vaults. Table 10 below provides the year over year breakdown of Network Vault Renewal investment spending including the actual historical spending from 2020-2022 and the bridge year estimates for 2023-2024. Table 11 provides a breakdown of the number of units attained in 2020-2022 and planned to be completed in the bridge years from 2023-2024.

Table 10: Network Vaults Renewals - Actual/Bridge ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0

Table 11: Volumes Actual/Bridge

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	
Vault Rebuild	9	3	4	8	9	43
Roof Rebuild	0	0	3	5	1	
Vault Decommission	0	1	0	0	0	

First, it should be noted that year-over-year fluctuations are primarily due to costs associated with particular vaults. Costs for civil work tend to vary significantly between projects as such projects tend to impact third-party infrastructure in close proximity. Furthermore, civil construction projects are impacted by timing and constraints imposed by other major City work, such as the Eglinton Crosstown LRT.

Between 2020-2024, Toronto Hydro has increased pacing and will proactively rebuild 10 additional network vaults than planned in 2024 in order to further reduce safety risks to Toronto Hydro employees and the public. Related to this, the costs for vault rebuilds have increased. This can be attributed to certain factors such as City permits only allowing more expensive nighttime work to be completed at certain locations, as well as the costs of civil work tending to vary greatly as projects are heavily impacted by the City and other utility infrastructure in the vicinity.

Furthermore, over the 2020-24 rate period, Toronto Hydro has completed an increased amount of legacy cable removal and upgrade work that was completed in the course of building new network vaults. A number of the targeted vaults contained AILC secondary cable, containing asbestos and lead, and/or have PILC cable that terminates at the network units. In the same vein, additional civil work was completed at certain locations to replace existing two units network vault by building two single unit vaults. This approach helps to save one network unit from catastrophic failure in case of a vault fire; only one network unit will be impacted rather than both units.

Moreover, the supply chain issues originating from the beginning of the pandemic proved to be a significant challenge for Toronto Hydro. As a result of factory closures in early 2020, freight costs and delivery times were heavily impacted and increased significantly. Furthermore, lockdowns worldwide, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, capacity issues, and material cost increases driven by raw material price increases were are all present throughout the 2020-2024 rate period.

Without intervention, Toronto Hydro forecasts that 137 network vaults will have at least material deterioration (HI4 and HI5) by 2029. Toronto Hydro therefore plans to spend $69.0 million to address 38 of the highest risk vaults during the 2025-2029 rate period (i.e. approximately seven vaults per year), which is in line with the 2020-2024 pace of renewal for these assets. A focust on replacement of units with the highest failure risk is expected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. Table 12 below provides the proposed year over year breakdown of units to be addressed from 2025-2029.

Table 12: Proposed Number of Units - Network Vault Renewal

Year	2025	2026	2027	2028	2029
Vault Rebuild	3	3	7	7	7
Roof Rebuild	0	0	3	2	3
Vault Decommission	0	0	1	1	1

Through this work, Toronto Hydro expects to improve safety and maintain reliability by removing potential trip and falling debris hazards and reducing the risk that any structural deficiencies could lead to damaged equipment. Where applicable, Network Vault Renewal work is combined with overlapping work in the other Network System segments to minimize resource requirements and costs. In addition, projects requiring civil construction work are coordinated with planned City road work to reduce costs associated with routing civil infrastructure around road moratoriums and road cut repairs.

E6.4.4.3 Network Circuit Reconfiguration

The Network Circuit Reconfiguration segment mitigates the impact of multiple contingency events on Toronto Hydro's network system. Throughout 2020-2022, Toronto Hydro spent $7.6 million on this segment and expects to spend $1.4 million over 2023-2024. Table 14 below provides the status of planned network circuit reconfiguration work for 2020-2024. This also includes the carryover work from the 2015-2019 rate period.

Table 13: Historical & Forecast Network Circuit Reconfiguration Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-

Table 14: Summary Status of Planned Projects 2020-2024

Network	Completion Year	CapEx ($ Millions)	Comments
Hammersmith Network Preparation	2021-2022	6.5	Carry Over Projects form 2015-2019 Rate Filing Period
Hammersmith Loc 4141 Ci			

Hammersmith Network Conv			
LOC 4174 Vault Rebuild to CC			
Carlaw E Network			
GD Phase 1	2021	0.88	Actuals: 2020-2022
A-North Phase-1	2023	1.7	Bridge Years: 2023-2024
CE-North (Carry Over)	2024		
CE-South Phase 1	2024		
GD Phase 2	2026	3.2	Forecast: 2025-2029
A-North Phase 2	2025		
CE-South Phase2	2027		
WR-West Phase 1	Beyond 2029		
WR-West Phase 2			
CS-West Phase1			
CS-West Phase2			

The variances between planned vs actual historical work, or planned vs forecast bridge years work for this segment has been due the following reasons:

- A large portion of the capital expenditures were dedicated to the completion of the carryover work from the 2015-2019 rate period including Hammersmith and Carlaw East Networks (approximately $6.5 Million).
- Material costs have increased significantly due to the COVID-19 pandemic and related supply chain issues, which resulted in increased raw material prices.
- Additional labour costs incurred due to overtime work mandated by the City's work zone coordinator, additional splicing work required on GD Phase-1 due to complexity of network and for handling of TTC cables and gas main found in the proximity of the cable chambers involved in reconfiguration process.
- Increased amount of legacy cable removal and upgrade work completed while reconfiguring the network secondary, as explained in Exhibit 2B, Section E6.3.
- At certain locations unanticipated civil work was completed during project execution due to location requirements.

Toronto Hydro plans to spend $3.2 million to reconfigure parts of three networks over the 2025-2029 rate period. Table 15 below lists the targeted networks for 2025-2029, these three networks are carried over from 2020-2024 rate period. These phases correspond to parts of the five largest networks and Toronto Hydro expects that the reconfigurations will help to improve outage restoration times and reduce the risks associated with second contingency events for downtown network customers.

Table 15: Planned Network circuit reconfiguration Projects for 2025-2029

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year	CapEx ($ Million)
A-North Phase 2	9	22	15	2025	3.2
GD Phase 2	9	25	20	2026	
CE-South Phase2	8	16	7	2027	

To minimize costs and resource requirements, Network Circuit Reconfiguration projects are combined with overlapping work in the other Network System Renewal segments, where applicable. Reconfiguration work can vary significantly from one network to another and this continues to hold true during the 2025-2029 rate period, where the four targeted networks service some of the largest loads with complex configurations.

E6.4.5 Options Analysis

E6.4.5.1 Options for Network Unit Renewal

Toronto Hydro considered the following options for addressing high failure risk network units.

9. **Option 1: Reduced Pace**

Under this option, Toronto Hydro would only target the 42 network units expected to be in at least “material deterioration” (HI4/5) by the end of 2029. While this option would mitigate reliability risks over the 2025-2029 rate period, with over 50 percent of network units expected to be at or beyond useful life by 2034, a reduced pace of asset renewal would result in a higher risk of power outages due to failure risk in the next decade. Therefore, to manage failure risk in the long term, Toronto Hydro would need to invest more to replace higher volumes of work in the next period at a higher cost. This would also reduce efficiency as it may require higher amounts of reactice and emergency work. As such, this option is not viable given the risks posed by these assets which include catastrophic failure due to poor condition; flooding; employee and public safety risks as well as environmental risks (e.g. oil leaks).

10. Option 2: Moderate Pace (Selected Option)

This option would address safety risks associated with deteriorating network units that would deliver reliability and efficiency benefits for the network system. At a pace of 26 units per year, 130 network units would be replaced and their associated safety, environmental and reliability risks addressed. These would address some legacy, non-submersible units in at least material deterioration thus minimizing the risk of failure due to flooding. Under this option, the utility expects the replacement of network units would result in avoided direct and indirect costs associated with asset failures across both periods, including but not limited to the cost of customer interruptions, emergency repair and replacement across the 2025-2029 rate period and beyond.

With over 50 percent of the network units expected to reach or go beyond useful life by 2034, the pace under this option would be expected to mitigate the risks associated with deteriorating and non-submersible network units and improve efficiency of the network system. However, units not replaced by 2029 or in a timely manner would continue to pose a higher risk of failure with the potential to cause fires or oil leaks until they are replaced. Some legacy, non-submersible units without material deterioration at an elevated risk of failure due to flooding, would also remain unaddressed.

This option is recommended as it reflects an appropriate trade-off between mitigating safety and environmental risks, reliability impacts, resource constraints, and program cost both in the short-term and in the future.

11. Option 3: Accelerated Pace

Under this option Toronto Hydro would replace network units at an accelerated rate of 40 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating and high failure risk network units. At this pace, Toronto Hydro would replace all of the 149 units forecast to have material deterioration (by 2029) and address an additional 51 units forecast to be at or beyond useful life in the next decade. While this option would minimize the number of network units at elevated risk of failure and would enable the utility to balance the number of units replaced across the 2025-2029 and 2030-2034 rate periods, it would cost roughly 1.5 times more than the proposed plan. As Customer Engagement results note that customers are supportive of Toronto Hydro's current pacing, this option cannot be justified. Additionally, this pace would not align with the utility's resources and system constraints. For these reasons, Option 3 is not a feasible strategy.

E6.4.5.2 Options for Network Vault Renewal

Toronto Hydro considered the following options for addressing network vaults in poor condition.

12. Option 1: Reduced Pace

In this option, Toronto Hydro would address immediate structural deficiencies of high-risk network vaults identified through the ACA process as having at least material deterioration ("HI4") at a reduced pace. The investment would only target about 22 network vaults (approximately 52 % of network vaults projected to reach HI4/HI5 from 2025 to 2029) thus it will significantly increase the backlog of HI4/HI5 vaults in the system that exists at the start of the 2025-2029 rate period. This option would not replace vaults at either the rate at which the HI4/HI5 population grow by each year, or the rate at which vaults on average reach normal lifespan.

This option is not viable as the multitude of issues discussed throughout the narrative, including structural failure may lead to failure of the equipment housed inside the vaults. Furthermore, safety risks (e.g. tripping, falling debris and fire hazards) for both the public and Toronto Hydro crews would be elevated. Major structural issues cannot be addressed through maintenance work.

13. Option 2 : Moderate Pace (Selected Option)

In this option, Toronto Hydro would proactively address the 38 network vaults which have at least material deterioration (HI4) at a modest pace to reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. At a pace of approximately 7 network vaults per year, this option would maintain the number of network vaults projected to reach HI4/HI5 at the level expected for 2025 but would not eliminate the backlog of HI4/HI5 vaults expected at the start of 2025. Based on historical experience, Toronto Hydro projects this pace to be achievable and would help mitigate the forecasted rise in the number of network vaults with material deterioration over the 2025-2029 rate period. Although Toronto Hydro would address the highest risk vaults, there would still be over 85 network vaults that have at least material deterioration (HI4) at the end of 2029. The backlog of these vaults would continue to pose elevated safety and reliability risks. However, this option would be expected to mitigate risks to an acceptable degree at a pace of work that would be realistic to achieve and at a reasonable cost.

14. Option 3: Accelerated Pace

By accelerating the pace of network vault renewal, Toronto Hydro would address the network vaults at an accelerated rate of 9 vaults per year to achieve faster reduction of safety and reliability risks associated with deteriorated and high failure risk network vaults. At this pace, Toronto Hydro would address more than the 42 network vaults forecast to have at least material deterioration (from 2025 to 2029) and would also slightly reduce the backlog of HI4/HI5 vaults discussed in above options. Reliability and safety risks of deteriorated network vaults would be reduced faster and to a greater degree than option 2 above but it would cost approximately 1.3 times more than the proposed pace for this segment. As Customer Engagement results note that customers are generally supportive of Toronto Hydro's current plan pacing, this would not be justifiable. In addition, this pace poses issues with resource and outage management resulting in delays of other planned work needed for the system. Therefore, this is not a recommended option.

E6.4.5.3 Options for Network Circuit Reconfiguration

15. Option 1: Reduced Pace (Selected Option)

This option for the 2025-2029 rate period would address three networks with reduced pace at a cost of $3.2 million. This would include completion of the GD Phase-2, A-North Phase-2, CE-South Phase-2. It would reduce the workload required to stabilize the networks and restore customers following multiple contingency events and reduce the time required to restore the networks to normal operation. The networks targeted under this option service large loads and have complex configurations, which means that they would benefit the most from reconfiguration.

There would be no additional network circuit reconfigurations work planned other than the carryover work from the last rate filing, detailed in Section E6.4.4.3. This will carry the risks of dropping other entire networks under 2nd contingency events into future years. It is the lowest cost option to complete the specified portion of carry-over work and improve the operability of three major networks under 2nd contingency events.

16. Option 2 : Moderate Pace

Under this option, Toronto Hydro would require $4.1 million to complete the projects mentioned in Option 1 plus CE-South Phase-2 network addition. This strategy would attain a total of 4 networks reconfigured rather than partially completed. Historically, network circuit reconfiguration projects have taken a long time to design and execute due to complexity of the secondary system in the downtown core. This can be attributed to the fact that a lot of civil infrastructure may need to be inspected to ensure that the proposed secondary cable reinforcements can be accomplished. Furthermore, as civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly. External to the program budget, Toronto Hydro spent $6.5 million to address carryover of work from the 2015-2019 rate period (See: Section E6.4.4.3). While this option would reconfigure two additional networks, it would cost roughly 1.5 times more than the proposed pace as well as not aligning with the utility's resources and system constraints. For these reasons, Option 2 is not recommended.

17. Option 3: Accelerated Pace

The improvement option would require $5.22 million to complete all five major networks. These networks are George & Duke, Windsor-West, Terauley-North, Charles-West, Cecil-South and Terauley-East. As reconfiguration projects have historically taken a long time to design, attempting to fit more projects within this 5-year period poses a feasibility risk. All major networks, covering large geographic areas of the downtown core, reside in areas of the city with aging infrastructure. As civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly, outside the budget of the program. Toronto Hydro estimates that this would require approximately double the financial and labour resources per year compared to the selected option and is therefore not recommended.

E6.4.6 Execution Risks & Mitigation

The Network System Renewal program is subject to the risks facing downtown underground programs and projects. For all segments, these risks include summer feeder restrictions. More specifically, many downtown network feeders have summer feeder switching restrictions imposed to prevent overloading cables and equipment during peak loading periods. To mitigate this risk, projects are scheduled to avoid the summer period if the feeders involved are restricted (i.e. do not have capacity). If a feeder is newly restricted in the project year, the project timeslot could potentially be exchanged with another project. If a restricted feeder supplies a vault being planned for rebuild, then the work may only be conducted during off-peak hours, and this may hinder project execution. Toronto Hydro's Load Demand program for the 2025-2029 rate application(see Exhibit 2B, Section E5.4 of the Distribution System Plan) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during summer peak times are minimized.

Each segment may also be subject to its own set of additional risks as discussed below:

- The City and Toronto Hydro's customers often have special events scheduled that can be negatively impacted by a major construction project. Toronto Hydro communicates with stakeholders and customers to establish an agreeable timeline in accordance with system priorities. Should a conflict arise, the project timeslot could potentially be exchanged with another project to allow the overall Program to proceed without negative impact.

- As part of Network safety enhancements, the unit cost of Network units will likely increase in the next few years. Some of the safety enhancements under consideration are:
    - External upper link boxes on protectors
    - New style antlers on protectors
    - Ethernet ready protector relay
    - Pro link style disconnect switches

- The removal of a network unit may cause the remaining network units to experience overloads. Toronto Hydro manages this risk by scheduling the replacement of problematic network units outside of the peak loading periods of the particular vault. For example, work on vaults supplying schools or buildings with electric heat may best be scheduled during the summer.

- City moratoriums and the Metrolinx subway expansion may impact execution timelines. Although existing City moratoriums are considered when planning vault renewal projects, it is possible that new moratoriums may be subsequently introduced. To mitigate this risk, Toronto Hydro reviews all new moratoriums and adjusts its work plans accordingly. Projects, such as the expansion of the transit system in Toronto, pose unique challenges. When such projects are in the execution phase, the City or Metrolinx may impose moratoriums that suspend all other work until critical phases of transit projects are completed. In addition, transit construction may require relocation of Toronto Hydro assets that impacts the Vault Renewal program. To mitigate this risk, Toronto Hydro communicates with Metrolinx on a continual basis to identify, monitor, and resolve conflicts.

- For the Network Circuit Reconfiguration segment, additional risks are posed by structures at the end of their useful lives and customer-owned civil structures. Projects in this segment typically involve the installation of new cabling within existing cable chambers and duct structures. There is a risk that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational benefits, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

- There also may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro’s work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Since the pandemic's beginning, supply chain disruptions have grown to be a significant challenge for Toronto Hydro. Freight costs and delivery times have significantly increased as a result of factory closures in early 2020, lockdowns in various nations across the world, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, and capacity issues. It is expected that by 2025-2029, capacity constraints and labor shortages should ease, taking some of the pressure off supply chains and delivery times. To mitigate this risk, Toronto Hydro’s procurement department will work closely with our suppliers and monitor manufacturing and delivery times closely to maintain project completion dates.

E6.5 Overhead System Renewal

E6.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 218.9	**2025-2029 Cost ($M):** 358.4
Segments: Overhead System Renewal, Overhead Infrastructure Resiliency	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness – Safety, Financial Performance	

The Overhead System Renewal program (the "Program") manages failure risk on Toronto Hydro's overhead system through the replacement of end-of-life and functionally obsolete assets that are in poor condition or otherwise require replacement to mitigate safety and environmental risks.

Additionally, the 2025-2029 iteration of this Program reintroduces the undergrounding or relocation of parts of Toronto Hydro's overhead system that are particularly vulnerable to external causes of failure or hard to access.

The Program is grouped into the two segments summarized below:

- **Overhead System Renewal:** This segment is a continuation of the Overhead System Renewal program outlined in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1] This segment addresses three major asset classes that are sufficiently critical as to require proactive lifecycle management strategies: (1) pole-top transformers; (2) poles and pole accessories; and (3) overhead switches. The probability that these assets will fail – causing negative impacts to safety, reliability, and the environment – increases as these assets age and deteriorate.

  The Overhead System Renewal segment consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are

[1] EB-2018-0165, Exhibit 2B, Section E6.5

typically addressed through rebuild projects. Voltage conversion is another important consideration for rebuilds. For example, Toronto Hydro has a significant population of deteriorating, legacy 4 kV overhead lines that it will gradually convert to modernized 13.8 kV or 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4 kV is no longer an accepted system standard, the deterioration of 4 kV asset condition and performance within an area will generally trigger a rebuild of the area to current standards.

Outside of rebuild project areas, any transformers at risk of containing PCBs greater than 2 ppm, will be addressed through targeted spot replacement projects. These projects do not involve the replacement of all assets in a continuous area.

A summary of this segment's investments in the three major overhead asset classes is as follows:

- **Pole-top Transformers:** One of the main drivers of poor performance in the overhead system is defective equipment. Through the focused renewal of PCB containing transformers (which are also past useful life and therefore at higher risk of failure) in recent years, Toronto Hydro has reduced the number of transformer-related customers interrupted and customer hours interrupted from over 10,000 customers interrupted and 6,000 customer hours interrupted and per year on average to 4,133 customers and 4,360 customer-hours interrupted per year on average over the last five years (2018-2022). This focused renewal has also reduced the proportion of overhead transformers past useful life from approximately 14 percent in 2017 to approximately 8 percent at the end of 2022. However, without further intervention, that number will return to 17 percent by 2029. By replacing all remaining PCB transformers by the end of 2025 and then shifting to steady transformer replacement through rebuilds of high-risk and poor performing areas, Toronto Hydro can ensure that the overhead transformers past useful life and the associated reliability and environmental risks remain within a reasonable range over 2025-2029 and beyond.
- **Poles and Accessories:** Pole failures can lead to extensive and prolonged service disruptions, as well as pose safety risks for utility crews and the public. Poles and pole accessories have contributed to over 30,700 customer interruptions and 18,000

customer hours interrupted per year on average over the past five years. Poles are frequently exposed to various severe weather conditions, and may become vulnerable to internal rot, decay, and infestation. These conditions, combined with the fact that approximately 23 percent of Toronto Hydro's wood poles are beyond their useful life as of 2022, make these poles more susceptible to failure. Approximately 9 percent of wood poles are already showing signs of material deterioration (as of 2022) and, without intervention, this proportion is forecast to increase to 30 percent by 2029. Toronto Hydro plans to replace a total of approximately 8,300 wood poles and associated accessories over the 2025-2029 period to reduce the aforementioned failure and safety risks.

- **Overhead Switches**: Overhead switches are constantly exposed to harsh environmental conditions. Their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. On average, overhead switches contributed to 37,070 customer interruptions and 20,263 customer hours interrupted annually between 2018 and 2022. Approximately 18 percent of gang operated switches and 33 percent of inline disconnect switches have reached the end of their useful life as of 2022. Toronto Hydro plans to replace a total of 510 overhead switches through rebuilds of areas with high concentrations of high-risk assets and poor reliability.

- **Overhead Infrastructure Resiliency**: This segment is a reintroduction and expansion of the work done through the Overhead Infrastructure Relocation program in Toronto Hydro's 2015-2019 DSP[2] to improve the resiliency of the overhead system through targeted relocation and undergrounding of overhead assets as summarized below:
  - Undergrounding critical sections of overhead infrastructure that are persistently affected by outages caused by external factors, such as adverse weather events and tree contacts, to reduce the frequency and impact of these types of outages for affected customers;
  - Relocating overhead sections in areas with limited access, such as heavily treed ravines, valleys, rail corridors, Hydro One rights-of-way ("ROW"), and certain trunk sections running along inaccessible rear lot locations.[3] These sections can be especially vulnerable

[2] EB-2014-0116, Exhibit 2B, Section E6.5.
[3] Note most rear lot assets are being addressed through the Area Conversion program, see Exhibit 2B, Section E6.1.

during major storm events such as heavy rainfall, floods, and ice storms and restoration following major storms is extremely challenging; and

  - Reconfiguring and, if necessary, undergrounding pole lines exiting stations that carry three or more circuits (referred to as congested egresses), which pose an unacceptable reliability risk due to vulnerability to factors such as adverse weather and the high number of customers connected to a single physical location.

The objectives of the Overhead System Renewal program for the 2025-2029 rate period are to:

- Renew deteriorated assets at a pace that aims to generally maintain asset condition and failure risk on the overhead system at current levels;
- Maintain overall system reliability and improve reliability for certain poorly performing areas of the overhead distribution system;
- Address the environmental risks of potential PCB oil spills by replacing all remaining transformers containing or at risk of containing PCBs; and
- Improve resiliency through targeted undergrounding or relocation of overhead assets that are at risk of adverse weather, tree contacts, animal contact, foreign interference and/or in areas that are difficult to access.

E6.5.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC")), by increasing overhead system capacity through voltage conversion from 4 kV and/or 13.8 kV to 27.6 kV in specified areas.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (as measured via metrics like SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ controlling the population of HI4 and HI5 condition[4] poles over the 2025-2029 period;

[4] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

	○ replacing pole-top transformers at higher risk of failure through area rebuild and spot replacement; and ○ Relocating and/or undergrounding assets in hard to access or vulnerable locations.
Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure, and environmental objectives and obligations by eliminating all equipment containing, or at risk of containing, PCBs from the overhead distribution system by the end of 2025 pursuant to PCB regulations (PCB Regulations,[5] made under the federal *Canadian Environmental Protection Act, 1999 and* Ontario's *Environmental Protection Act, 1990*[6] and, City of Toronto's Sewer Use By-Law.[7]
Operational Effectiveness - Safety	• Toronto Hydro and contractor crew safety improved by relocating assets to improve accessibility
Financial Performance	• Voltage conversions enables a reduction in line losses which in turn leads to savings for our customers. • Once an MS Station's feeders have been fully voltage converted; the Station is decommissioned which results in reduced need for capital and maintenance investment. • Improve maintenance costs incurred on assets located at inaccessible locations by relocating assets to areas of better access

[5] PCB Regulations (SOR /2008-273), under the *Canadian Environmental Protection Act,* 1999.
[6] *Environmental Protection Act,* RSO 1990, c E. 19.
[7] City of Toronto, by-law No 681, *Sewers,* (May 15, 2023).

E6.5.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure risk
Secondary Driver(s)	Environmental Risk, Reliability, Safety, Functional Obsolescence, System Efficiency

The Overhead System Renewal program is driven by failure risk of assets on the Overhead System due to age, condition, obsolete design or location, which can negatively impact reliability, safety, and the environment. The Program replaces at-risk assets and, where appropriate, will relocate or underground them to address location-specific vulnerabilities.

E6.5.3.1 Overhead System Renewal

The Overhead System Renewal segment focuses on replacing three types of assets: (i) pole-top transformers; (ii) poles and accessories; and (iii) overhead switches. This renewal segment is driven by the risk and impact of overhead distribution asset failures on system reliability and safety due to accelerated asset condition degradation resulting from factors such as: sustained exposure to dirt, salt, dust, moisture and humidity, and assets approaching end of their useful life. Customer Engagement results have shown that reliability is a top priority for all types of customers.[8]

Asset failures on Toronto Hydro's distribution system present reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with interrupted feeders or assets that cannot provide backup supply in the event of a subsequent outage).

Over the last five years the main known cause of outages in the overhead system is defective equipment as shown in Figure 1. Foreign interference is the second main known cause of outages and these are addressed primarily through the Worst Performing Feeder segment.[9] Without renewal, the risk of overhead asset deterioration and failures would increase, resulting in more frequent and longer outages which would result in an increase in reactive replacement work.

[8] Exhibit 1B, Tab 3, Schedule 1
[9] Exhibit 2B, Section E6.7

Figure 2 shows the volume of reactive capital work requests generated to address overhead system related deficiencies between 2019 and 2022. On average, about 463 such work requests were initiated annually over that period, which is an improvement compared to the 2013-2017 average of 550 per year. Timely replacement of aged and deteriorated equipment before failure can effectively mitigate the frequency and duration of interruptions experienced by customers due to failing overhead assets.

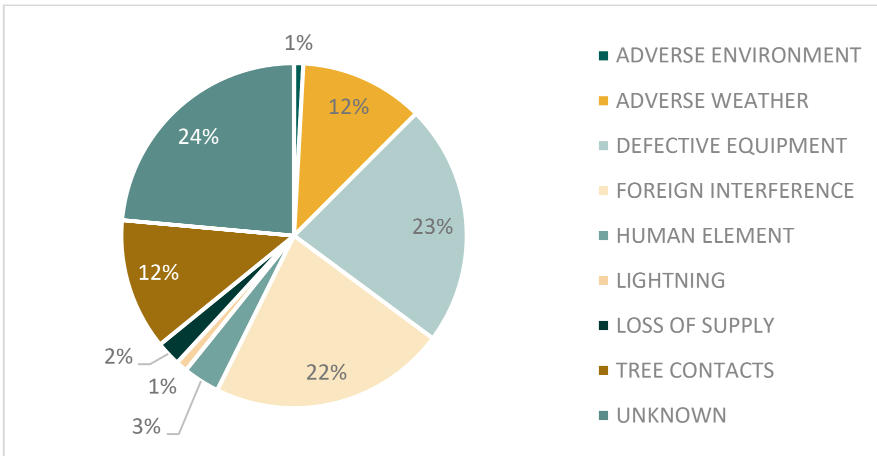


Figure 1: Overhead System Outages by Cause Code 2018-2022 (Excluding MEDs and Planned Outages)

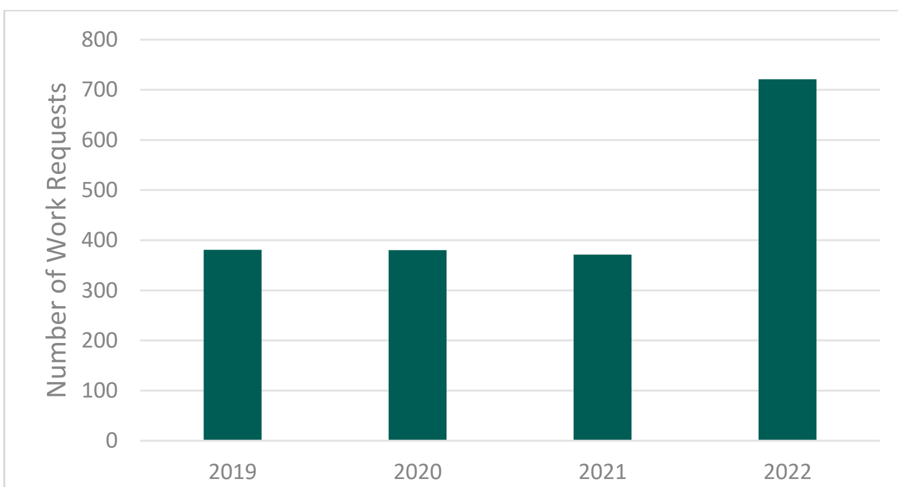


Figure 2: Reactive Work Requests to replace Overhead Assets from 2019-2022[10]

[10] 2018 data is excluded due to the transition to SAP that occurred during that year

The reliability outcome of historical investments in the Overhead System Renewal program is illustrated in Figures 3 and 4, which illustrate the effects of outages on customers; customers interrupted ("CI") and customer hours interrupted ("CHI"). Compared to 2013-2017, on average system wide reliability measures have remained steady. This result is consistent with the objectives that Toronto Hydro set out to achieve in the previous rate application, which was to maintain overall reliability.

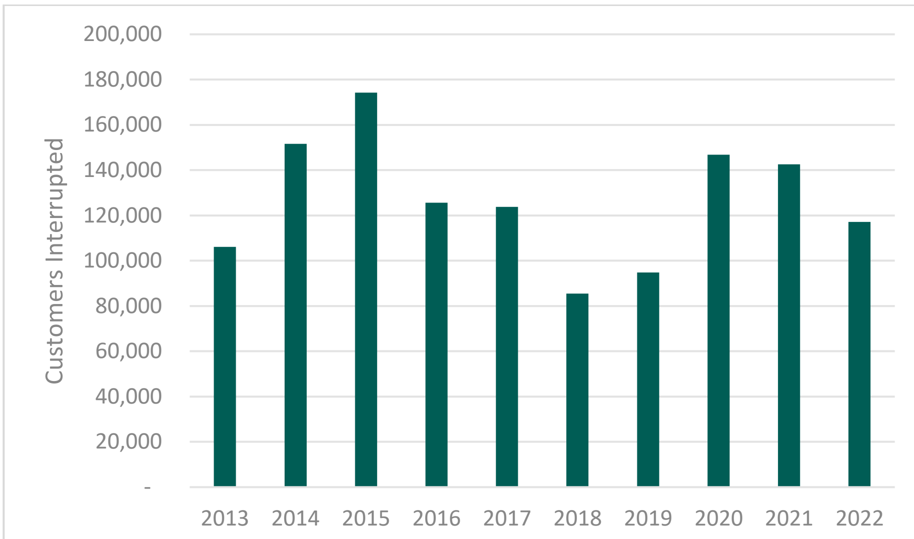


Figure 3: Customers Interrupted ("CI") on the Overhead System (2013-2022)

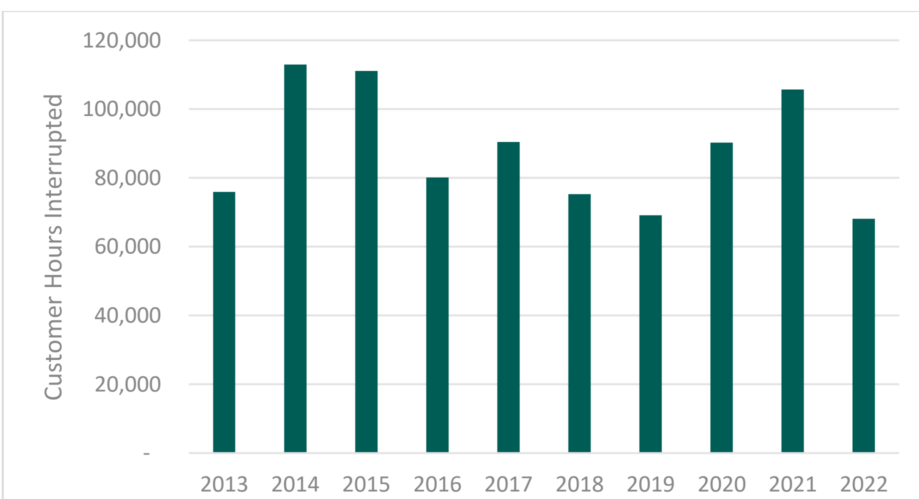


Figure 4: Customer Hours Interrupted ("CHI") on the Overhead System (2013-2022)

Toronto Hydro must slightly increase its pace of investment in the Overhead System Renewal segment in order to prevent reliability risk from increasing. Asset investment is necessary to address the large number of overhead assets that are expected to deteriorate in the coming years as they approach the end of their useful life or remain in service well beyond it.

Table 3 summarizes the age demographics for poles, transformers and switches in 2022 and by 2029 (without investment).

Table 3: Asset Demographics

	Population	Typical Useful Life (Years)	Assets Past Useful Life as of 2022 (%)	Assets Past Useful Life in 2029 without Investment (%)
Wood Poles	108,988	45	23	29
Concrete Poles	49,059	55	13	22
Overhead Transformers	27,690	35	8	17
Overhead Load Break Gang Operated Switches	3,015	30	18	26
Overhead Disconnect Switches	4,425	30	33	54

Table 4 shows the condition of Toronto Hydro's poles in 2022 and by 2029 (without investment).

Table 4: Condition Data for Wood Pole

Asset Condition Index	2022	2029 (Without Investment)
HI1 – New or Good Condition	68,193	60,253
HI2 – Minor Deterioration	7,536	8,310
HI3 – Moderate Deterioration	21,015	5,544
HI4 – Material Deterioration	8,918	24,404
HI5 – End-of-serviceable Life	504	7,655

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 4,848 overhead transformers, 8,338 poles, and 510 switches over the 2025-2029 period.

Any targeted overhead areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. The underground portion of these feeders is addressed by the Underground System Renewal - Horseshoe program.[11] Likewise, there are 4.16 kV systems in the rear lot, or the backyards, of customers that are addressed by the Area Conversions program.[12] There is a growing number of 4 kV and 13.8 kV feeders where customers have sustained outages (sometimes multiple) of ten hours or more. These are legacy assets which cannot be easily replaced, and their configurations do not allow for expansion or provide many options for system restoration contingency. Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the ends of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system to prepare for the demands of electrification, growth, and the proliferation of DERs that the 4kV cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, thereby avoiding operating and maintenance expenditures that would otherwise need to be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert the overhead portions of 48 of these feeders and the underground portions of 29 of these feeders by 2029. At this pacing Toronto Hydro expects to complete the overhead voltage conversion portion of the entire system by 2049.

1. Replacement of Overhead Transformers

Through the Overhead System Renewal segment, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing an environmental risk due to oil leaks that may contain PCBs. There are currently 27,690 overhead transformers in Toronto Hydro's distribution system. As a critical component of Toronto Hydro's overhead system, transformers are used to step down primary distribution voltage to levels required to supply residential and commercial customers. They are mounted on poles and consistently exposed to external elements that cause degradation (e.g. weather conditions, dust, salt, moisture, cyclical loading, faults and humidity). In particular, exposure to precipitation and humidity over time causes corrosion (tank perforation) which can lead to oil leakage into the environment. Figure 5 shows the reactive work

[11] Exhibit 2B, Section E6.2.
[12] Exhibit 2B, Section E6.1.

requests to replace failed or severely deteriorated pole-top transformers during the 2019-2022 period. Figure 6 shows the forced pole-top outages during the 2018-2022 period (note not all reactive work is tied to an outage).

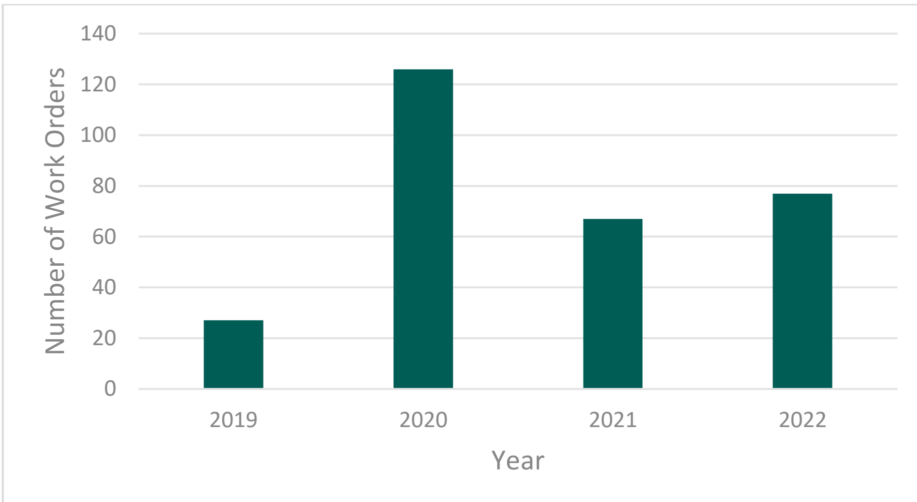


Figure 5: Reactive Work Requests for Pole-top Transformer Replacement[13]

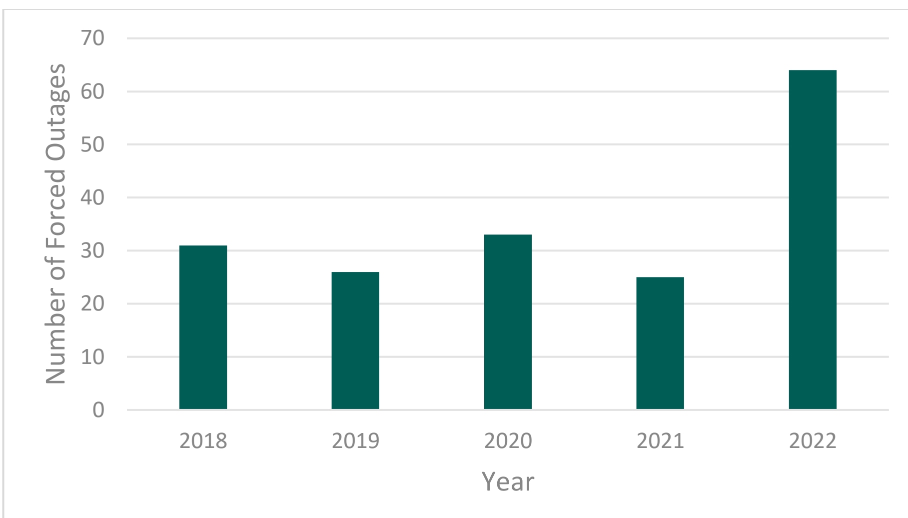


Figure 6: Forced Outages for Pole-top Transformers

On-going renewal work has contributed to an overall average decline in reactive work requests, however in 2022 there was a spike of 64 outages (versus an average of 35 outages over the five-year

[13] 2018 data is excluded due to the transition to SAP that occurred during that year

period). The vast majority of outages relate to transformer failures (approximately 31 to 64 failures per year), contributing to over 4,133 CI and 4,360 CHI over the same period on average (see Figures 7 and 8). In 2022, consistent with the number of outages, both CI and CHI have noticeably increased compared to recent averages – to 7,643 customers and 8,588 hours, respectively. This can be explained in part by the fact that Toronto Hydro has recently implemented more granular automated outage reporting as discussed in Exhibit 2B, Section C. There was also an abnormal number of customers interrupted because of one individual incident. Similarly, the increase of CI in 2020 is attributed to a single outage impacting a relatively large number of customers.

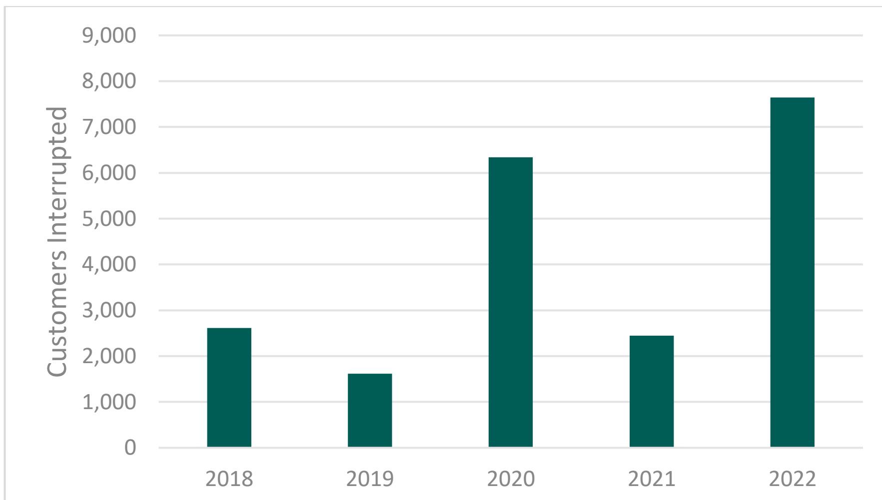


Figure 7: Customers Interrupted ("CI") for Pole-top Transformers

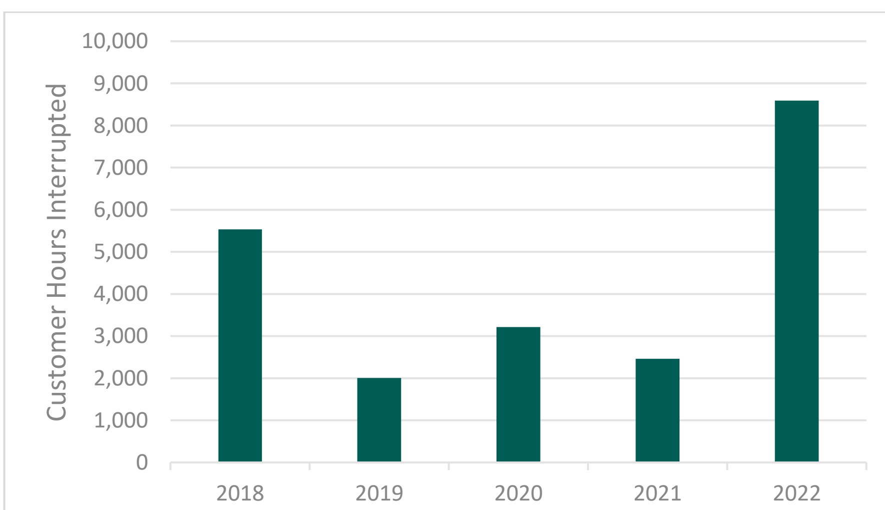


Figure 8: Customer Hours Interrupted ("CHI") for Pole-top Transformers

A number of overhead transformer failures have resulted in oil leaks into the environment. Figure 9 shows the total number of reported oil spill incidents for pole-top transformers during the 2018-2022 period. In recent years the number of spills has declined as Toronto Hydro has targeted the most at-risk transformers for replacement, aiming to replace these transformers prior to failure or before spills can occur. Specifically, older transformers are at an especially high risk of having oil containing PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the federal *Canadian Environmental Protection Act, 1999*[14] (including the PCB Regulations made thereunder),[15] Ontario's *Environmental Protection Act, 1990*[16] and the City of Toronto's Sewer Use By-Law.[17] Toronto Hydro has been targeting overhead transformers at risk of containing PCBs, which are all also past their useful life, and estimates there will be 223 overhead transformers that contain or are at-risk of containing PCBs remaining by the end of 2024.[18] Toronto Hydro intends to replace all of these units by the end of 2025.

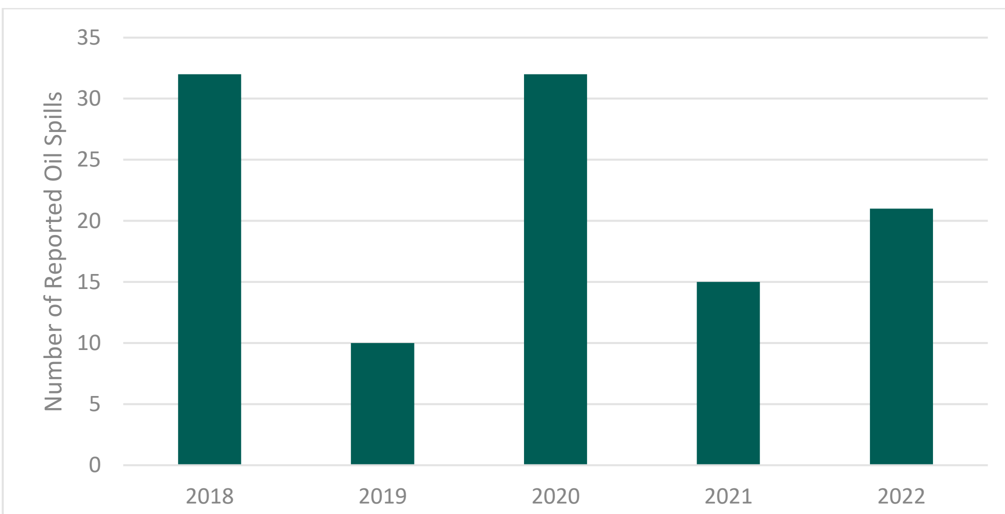


Figure 9: Number of Reported Pole-top Transformer Oil Spills

The utility investigated 547 failed overhead transformers between 2018 and 2022 to identify root causes of failure. The investigations found that 44 percent of the failed overhead transformers failed at or past the end of their useful life and that the number of failures increased with transformer age (see Figures 10 and 11). This is consistent with the expectation that transformers which are at or past

[14] *Supra* note 6.
[15] *Supra* note 5.
[16] *Supra* note 7.
[17] *Supra* note 8.
[18] Compared to approximately 6,400 at the end of 2017.

their useful life of 35 years are subject to an increased risk of failure. Most of the 4kV or 13.6kV system's transformers are also past their useful life, so by converting the system to 27.6kV these potentially failing transformers are removed from the population. In addition, Toronto Hydro, while conducting line patrols, identifies any transformers that show visual signs of deterioration for replacement.

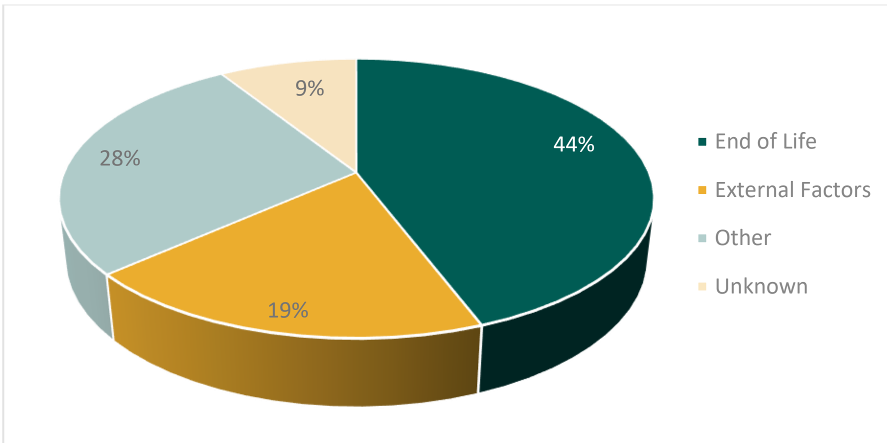


Figure 10: Root Cause Distribution for Failed Overhead Transformers from 2018-2022

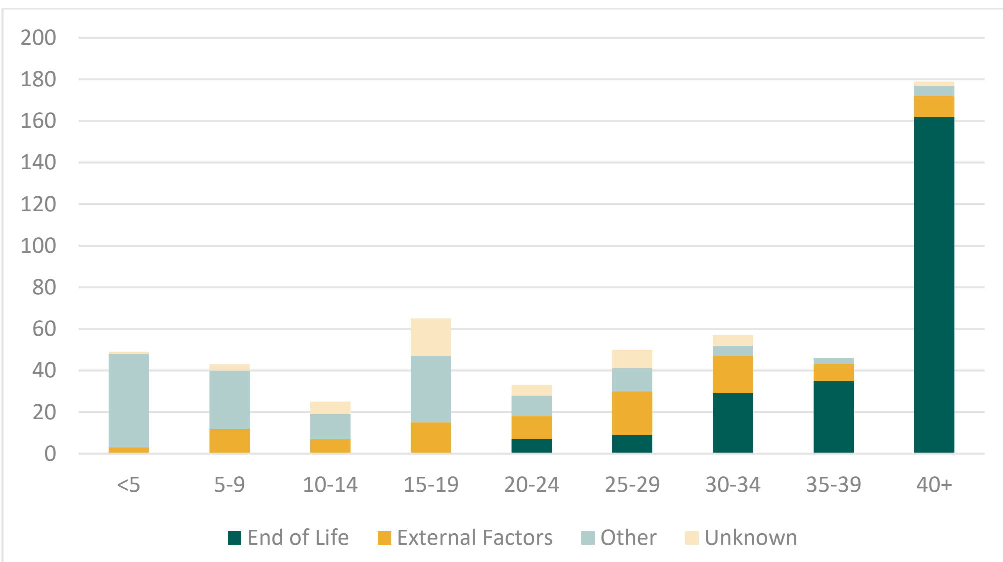


Figure 11: Age and Cause Distribution for Failed Overhead Transformers 2018-2022

Figure 12 shows the age distribution of overhead transformers in 2022 and in 2029 without investment. As of 2022, 2,245 transformers (8 percent) have surpassed their useful life of 35 years.

This is a significant improvement over 2017, when 14 percent were past useful life, and is expected to continue to improve due to the ongoing work to remove all the remaining overhead transformer at risk of containing PCBs. However, by 2029, without investment, the number of transformers past useful life will more than double to 4,747, and an additional 6,866 transformers will be within five years of end of life. Once all of the transformers at risk of containing PCBs have been removed, Toronto Hydro will shift away from spot replacements of transformers, and proactively replace them at a steadier pace through area rebuilds only. Using this approach, Toronto Hydro can ensure that the overhead transformers past useful life and associated reliability and environmental risks remains within a reasonable range over 2025-2029 and beyond, while taking advantage of the efficiencies (and other benefits such as reduced customer disruption) associated with area rebuild work.

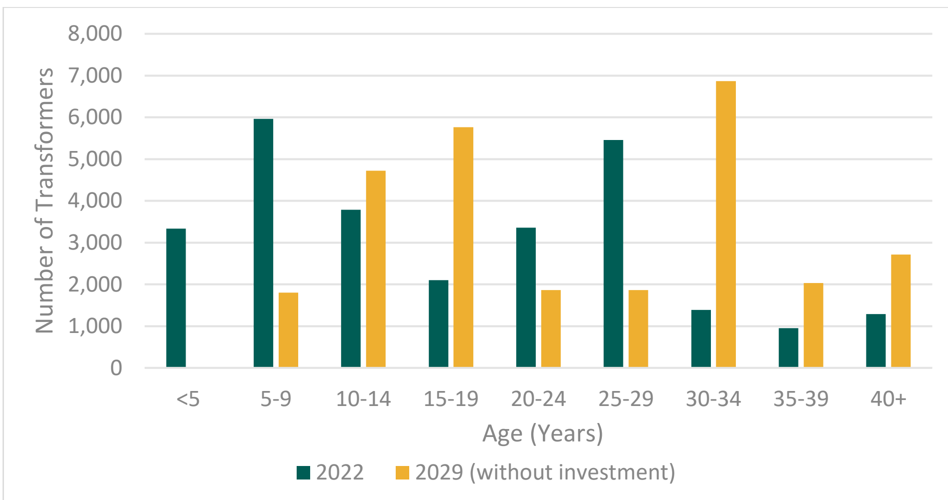


Figure 12: Age Distribution of Overhead Transformers in 2022 and 2029 (without investment)

Toronto Hydro will generally replace overhead transformers like-for-like unless undertaken as part of voltage conversion. However, one of the factors considered is whether the transformer in question is adequately satisfying design and policy requirements. In some cases, existing transformers are overloaded because they are oversupplying the total demand of secondary customers so they need to be upsized or a new transformer needs to be installed along with the one being replaced. Toronto Hydro also considers the City of Toronto's development pipeline[19] and future growth drivers, such as EV penetration when determining if upsizing or adding an additional transformer is required.

[19] Exhibit 2B, Section B2.2

2. Replacement of Poles and Accessories

Through the Overhead System Renewal segment, Toronto Hydro also replaces wood and concrete poles showing material deterioration as well as deteriorating or obsolete overhead accessories such as porcelain insulators and non-standard animal guards.

Toronto Hydro has approximately 108,988 wood poles and 49,059 concrete poles in service. Poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. Figures 13 and 14 show the contribution of poles and pole accessory related outages towards CI and CHI over 2018-2022. Poles contributed on average 6,627 customer interruptions and 4,700 customer hours of interruption per year over the last five years and these increase to 30,740 customers and 18,018 customer hours interrupted per year when also considering pole accessories. For the years 2019 and 2021, there were two lighting arrestor outages on the main trunk portion of a feeder that contributed to approximately 13,750 and 9,125 customers out of service respectively. Toronto Hydro has generally been successful in maintaining pole-related reliability and needs to continue proactively investing in pole renewal to manage pole failure risks.

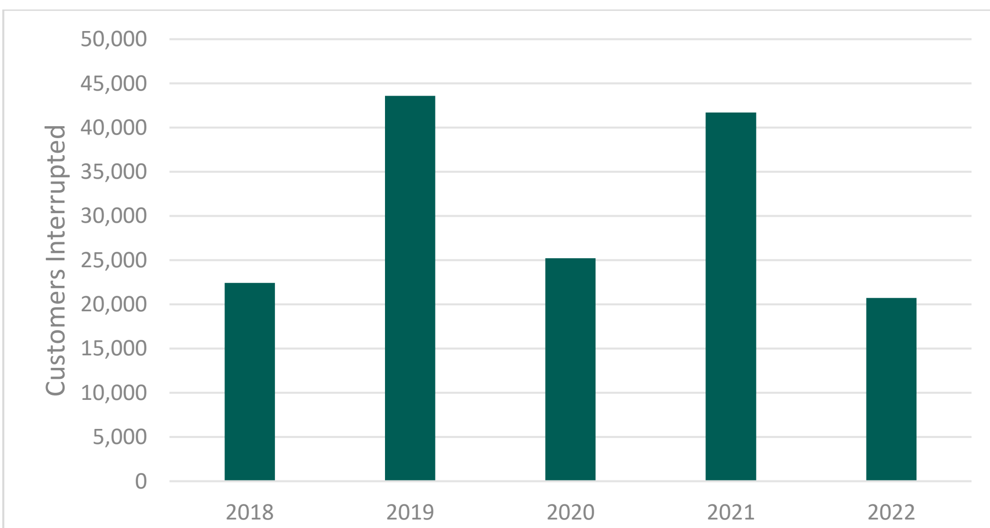


Figure 13: Customers Interrupted ("CI") for Poles and Pole Accessories

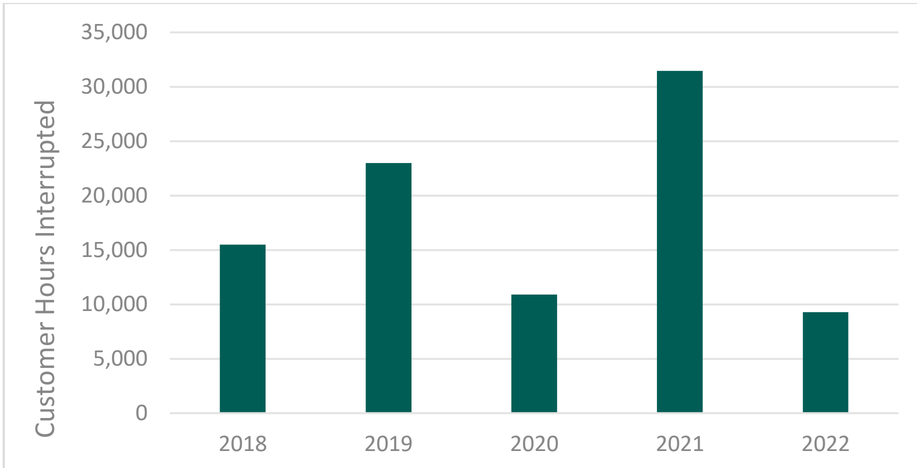


Figure 14: Customer Hours Interrupted ("CHI") for Poles and Pole Accessories

Poles with reduced strength present operational risks to Toronto Hydro crews, safety risks to the public, and reliability risks to the overhead distribution system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios where one failure can trigger cascading failures on a pole line (i.e. drop of multiple poles and associated equipment, hardware and conductor to the ground). Figure 15 illustrates that, despite ongoing renewal, approximately 287 poles on average had to be replaced reactively per year between 2019 and 2022. Reactive work is variable by its nature and the number of reactive pole replacements can vary year-to-year due to a number of factors, including the number of condemned poles replaced reactively versus through proactive renewal projects and the condition of the poles. However, as discussed below, pole age and condition demographics indicate a continued need to invest in proactive pole renewal to avoid a sustained increase in the need for reactive replacements and related reliability and safety risks.

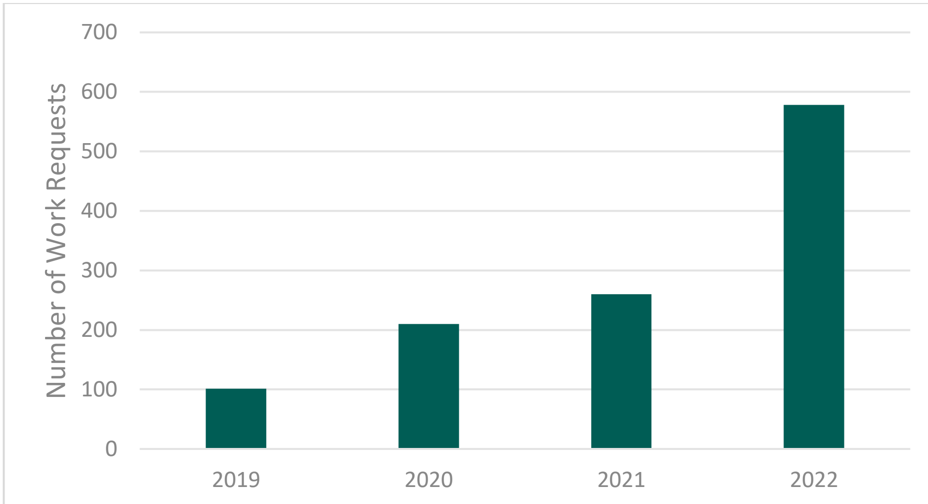


Figure 15: Reactive Work Requests for Pole replacement

In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. It is imperative that Toronto Hydro remains diligent and proactive in managing pole failure risks through pole replacements either through spot replacements or rebuilds.

Figures 16 and 17 show the age demographics of Toronto Hydro's wood and concrete poles (which have a typical useful life of 45 years and 55 years, respectively) as of 2022. A significant number of poles on Toronto Hydro's distribution system have already passed their useful life.

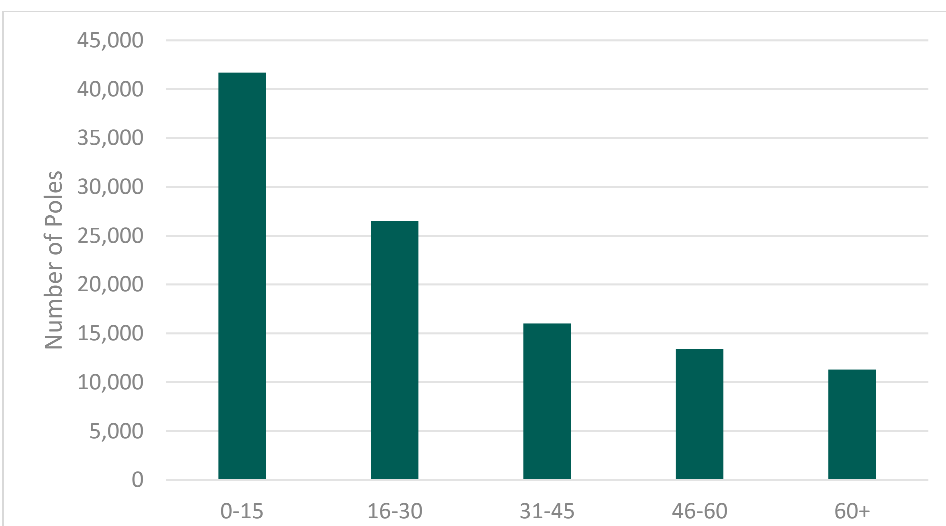


Figure 16: Age Distribution of Wood Poles (2022)

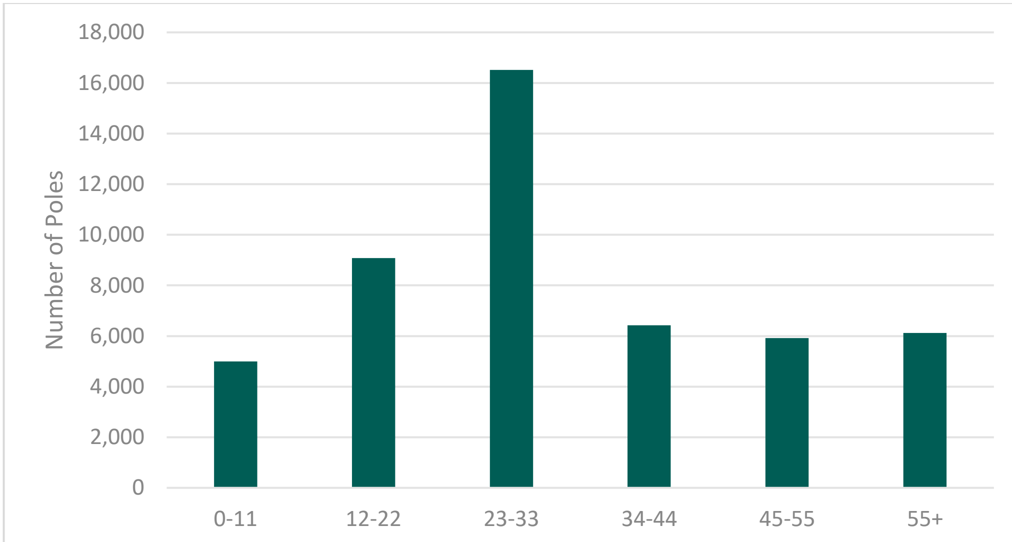


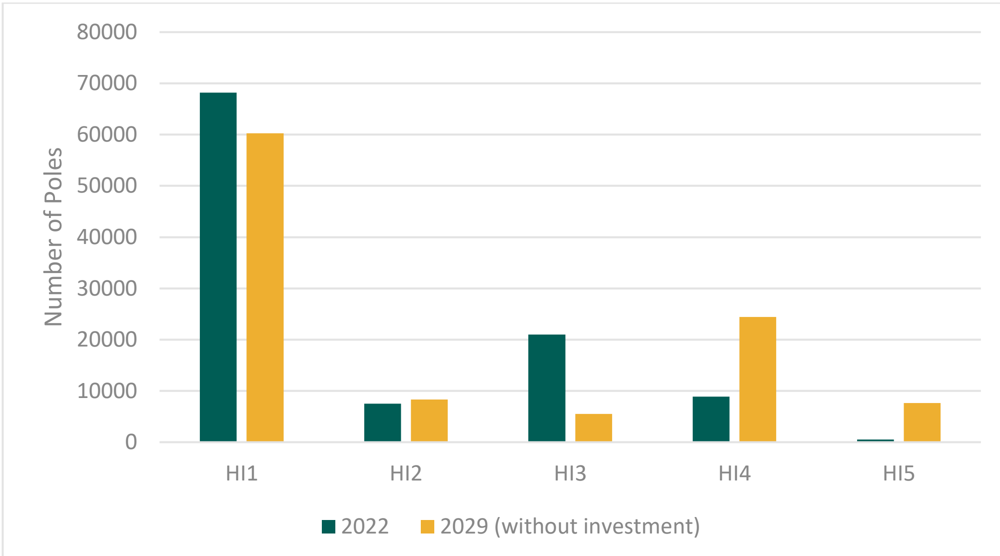
Figure 17: Age Distribution of Concrete Poles (2022)

Based solely on age, an estimated 23 percent or 24,958 wood poles and 13 percent or 6,505 concrete poles require immediate intervention to mitigate failure risk. However, Toronto Hydro plans to replace only aged poles in the worst condition.

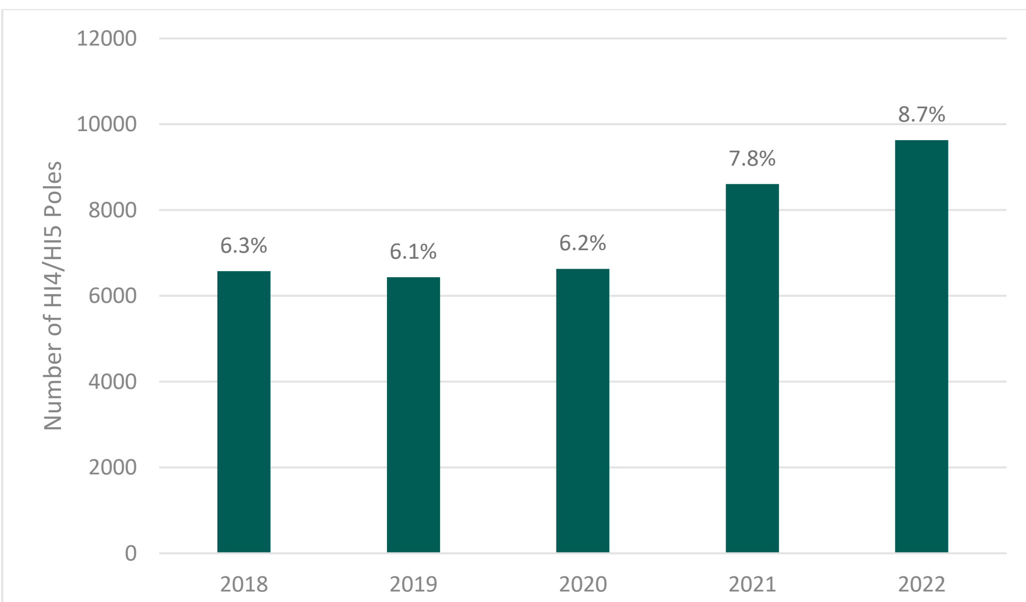
The overall condition of poles is assessed through Toronto Hydro's pole inspection program.[20] The results of inspections from this program support Toronto Hydro's Asset Condition Assessment ("ACA") for wood poles. Toronto Hydro's current ACA methodology was first established in 2017; the methodology assigns a health score for condition (summarized into "Health Index (HI)" bands) to a pole based on predetermined criteria (as detailed in Exhibit 2B, Section D, Appendix A). Wood poles are vital assets to the overall overhead system and serve as an indication of overall distribution system health. The ACA results as of the end of 2022 indicate: approximately 9 percent of Toronto Hydro's wood poles (9,422) show signs of material deterioration and or are at end of serviceable life (classified as HI4 and HI5, respectively), and 20 percent of wood poles (21,015) show signs of moderate deterioration (classified as HI3), as shown in Figure 18. Toronto Hydro includes the System Health (Asset Condition) – Wood Poles measure in its 2020-2024 CIR Custom scorecard.[21] System Health is defined as the percentage of HI4 and HI5 poles over the entire pole population. Toronto Hydro's performance on this measure since 2018 is shown in Figure 19. While the Overhead System

[20] Exhibit 4, Tab 2, Schedule 1.
[21] EB-2018-0165, Exhibit 2B, Section C2.

1 Renewal segment is the biggest contributor to Toronto Hydro's performance on this metric, other
2 programs, such as Area Conversions and Reactive and Corrective Capital,[22] also contribute.



3 **Figure 18: Condition of Wood Poles in 2022 and 2029 (without investment)**



4 **Figure 19: System Health (Asset Condition) – Wood Poles (2018-2022)**

[22] Exhibit 2B, Section E6.1 and E6.7

The system health of wood poles has worsened over the past two years (as shown in Figure 19). This is attributed in part to the recent focus of capital renewal work on removing overhead transformers at risk of containing PCBs rather than rebuilds and conversions. Toronto Hydro is planning to replace 8,338 poles in HI4 and HI5 condition by the end of 2029 through overhead rebuild and conversion projects in areas with poor reliability and high concentrations of assets beyond useful life as well as through spot replacements.

In addition to replacing poles with material deterioration, the Overhead System Renewal segment replaces deteriorating and obsolete overhead accessories such as porcelain insulators, porcelain lightning arrestors, and non-standard animal guards. Pole accessories were the single largest contributor to forced outages on the overhead system in 2018-2022. Toronto Hydro's legacy insulators are predominantly porcelain, which has been used in insulation for switches, lightning arrestors, terminators, and line post insulators. Porcelain insulators possess high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, it is susceptible to contamination build-up, and the accumulation of dirt and salt combined with moisture can lead to insulator tracking, flashover, cracks, insulator shattering and pole fires.

Table 5 shows the total number of pole fire incidents on Toronto Hydro's distribution system from 2015 to 2022. The number of pole fires from one year to the next can vary significantly as risks are related to weather conditions and the presence of contaminants (such as road salts and brines). The impact of a high number of pole fires in 2015 demonstrated how disruptive such incidents can be for the distribution system. The significant reduction in pole fire incidents after 2015 is due to the replacement of porcelain insulators with polymer insulators under a targeted replacement initiative in conjunction with increased insulator washing under the maintenance programs.[23] Toronto Hydro continues to perform regular insulator washing and replaces porcelain insulators as part of pole replacements to mitigate the risk of pole fire incidents.

[23] Exhibit 4, Tab 2, Schedule 1-4.

Table 5: Pole Fire Incidents

Year	Number of Pole Fire Incidents
2015	121
2016	39
2017	27
2018	8
2019	4
2020	17
2021	15
2022	28

3. Replacement of Overhead Switches

The last category of assets replaced through the Overhead System Renewal program is overhead switches. Overhead switches are a critical component of the distribution system that facilitate the isolation of feeder sections or equipment for maintenance during interruptions for load shifting and other operating requirements. They also allow workers to operate safely by isolating feeder sections and creating zones that are free of energized equipment. Toronto Hydro uses two types of switches in its overhead system: in-line disconnect switches and gang operated load break switches, each of which includes both manual load break switches and SCADA controlled switches. Currently there are 3,015 gang operated load switches and 4,425 in-line disconnect overhead switches in the overhead system.

Overhead switches are constantly exposed to harsh environmental conditions such as wind loading and salt spray. These switches can suffer either mechanical failure during operation or electrical failure via a flashover. Failed switches often lead to prolonged outages and pose significant safety risks to utility workers if an arc flash happens during switch failure. Gang operated and SCADA controlled switches were all inspected over 2020-2022 and, on average, 17 percent where found to have a defect such as corrosion. Figure 20 illustrates that 75 reactive work requests were initiated to address the defects found on switches in the overhead system between 2019 and 2022. Figures 21 and 22 show that, especially in recent years, overhead switches continue to contribute significantly to overhead customer outage frequency and duration. Gang Operated type switches, mostly SCADA-Mate, have contributed the most to reliability metrics since 2020 due to these types of switches operating on the trunk part of the feeder. When there is a failure on these types of switches, the impact is severe, affecting a large number of customers. On average over the past five years, overhead switches contributed to 37,070 customers interrupted and 20,264 customer hours of interruption per year.

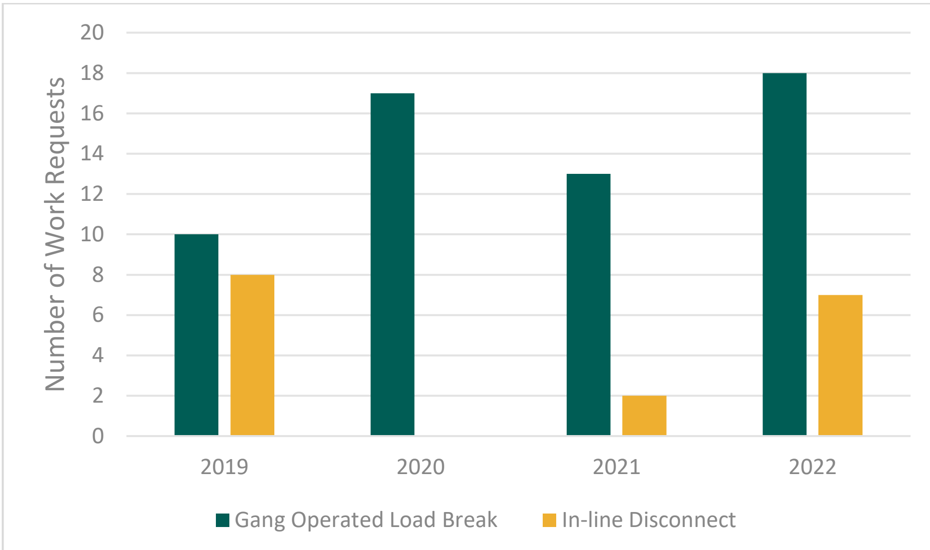


Figure 20: Reactive Work Requests for Overhead Switches

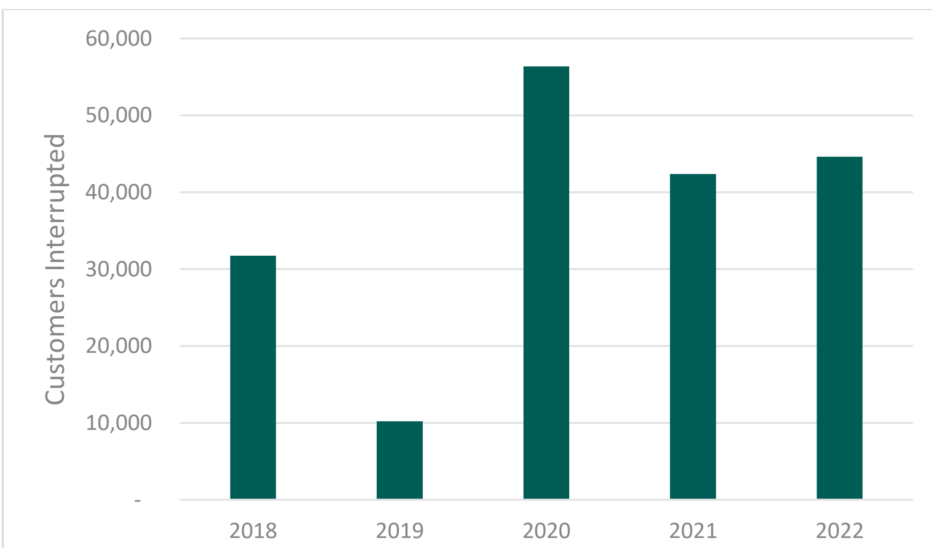


Figure 21: Customers Interrupted ("CI") for Overhead Switches

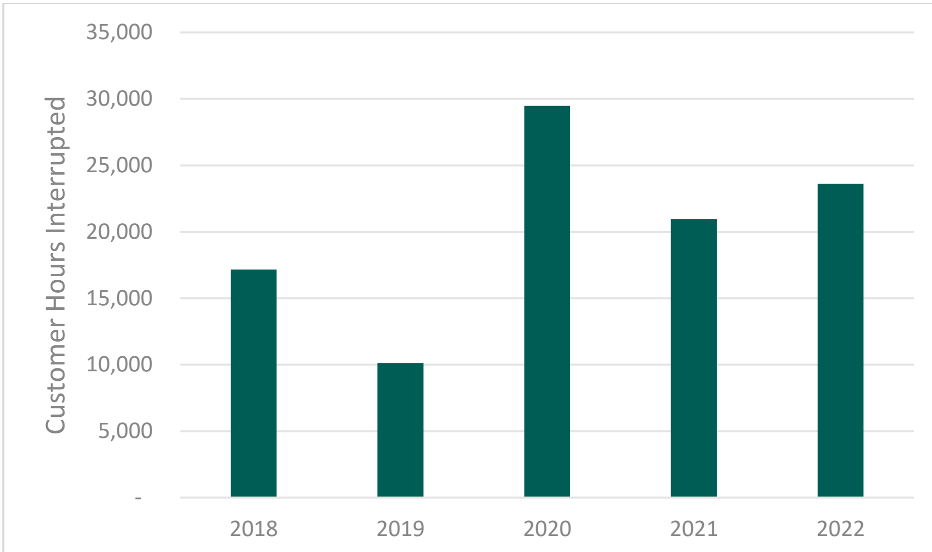
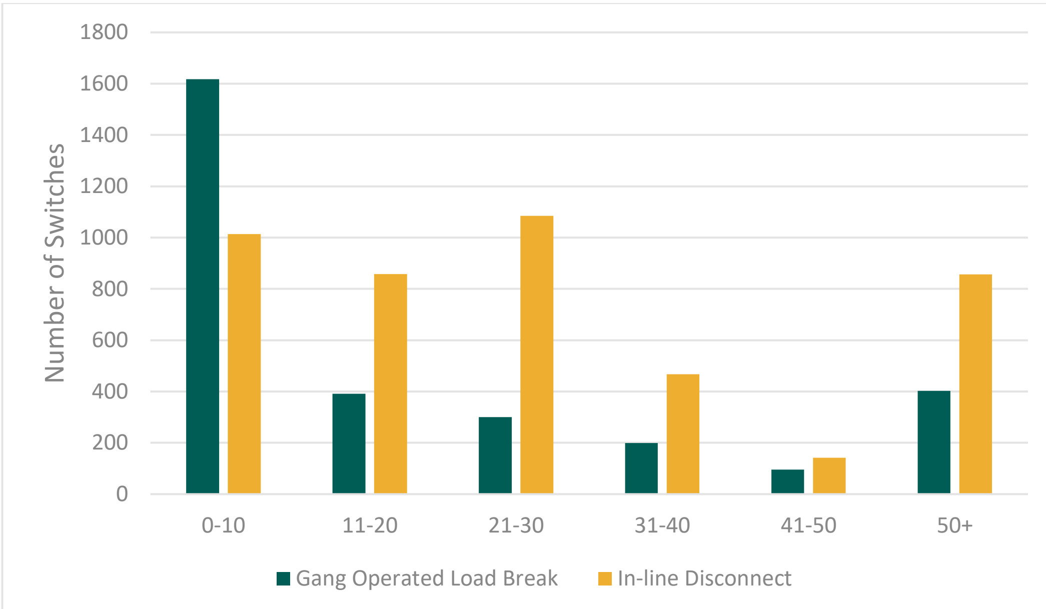


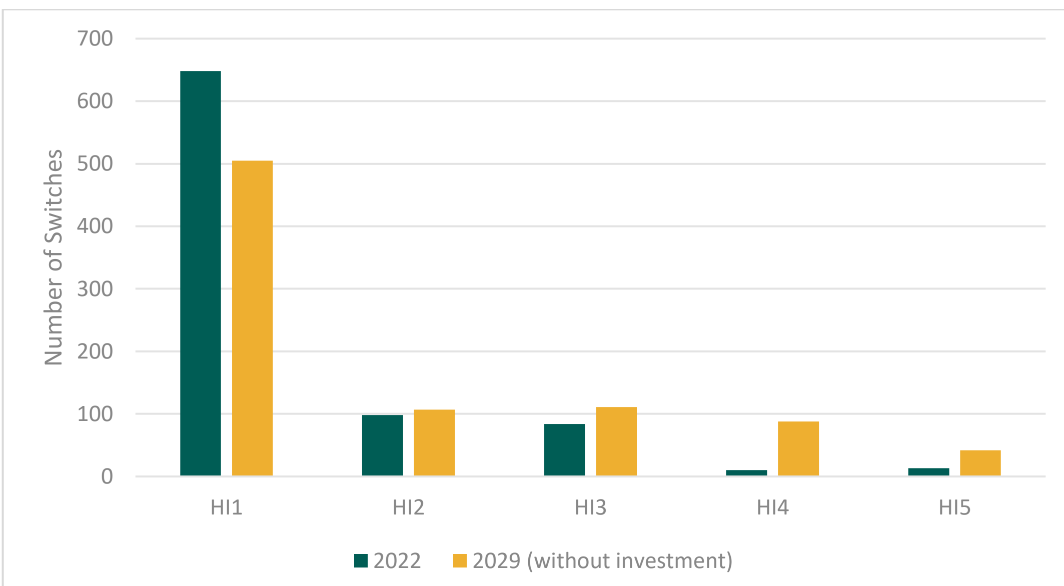
Figure 22: Customer Hours Interrupted ("CHI") for Overhead Switches

Gang operated load break overhead switches and in-line disconnect switches both have a useful life of 30 years.[24] Approximately 18 percent of gang operated switches and 33 percent of in-line disconnect switches have reached the end of their useful life as of 2022. Figure 23 shows the age demographics of Toronto Hydro's overhead switches in 2022. To support maintaining reliability risk, Toronto Hydro needs to continue its steady renewal of overhead switches to keep pace with the aging asset population and prevent an increase in failure rates. Figures 24 and 25 show the asset conditions of overhead gang operated and SCADA-Mate switches. While historically these types of switches have been in relatively good condition compared to the other overhead assets, the population of switches showing at least material deterioration (classified as HI4 and HI5) is expected to increase without proactive renewal.

[24] Previously Gang operated load break overhead switches had a useful life of 40 years while inline disconnect switches had a useful life of 45 years, but these have been reduced to 30 years based on review and insights gained from participation in the utility's latest Depreciation Study filed at EB-2023-0195, Exhibit 2A, Tab 2, Schedule 1, Appendix D



1 **Figure 23: Overhead Switch Age Demographics (2022)**



2 **Figure 24: Condition of Overhead Gang Operated Load Break Switches in 2022 and 2029 (without**
3 **investment).**

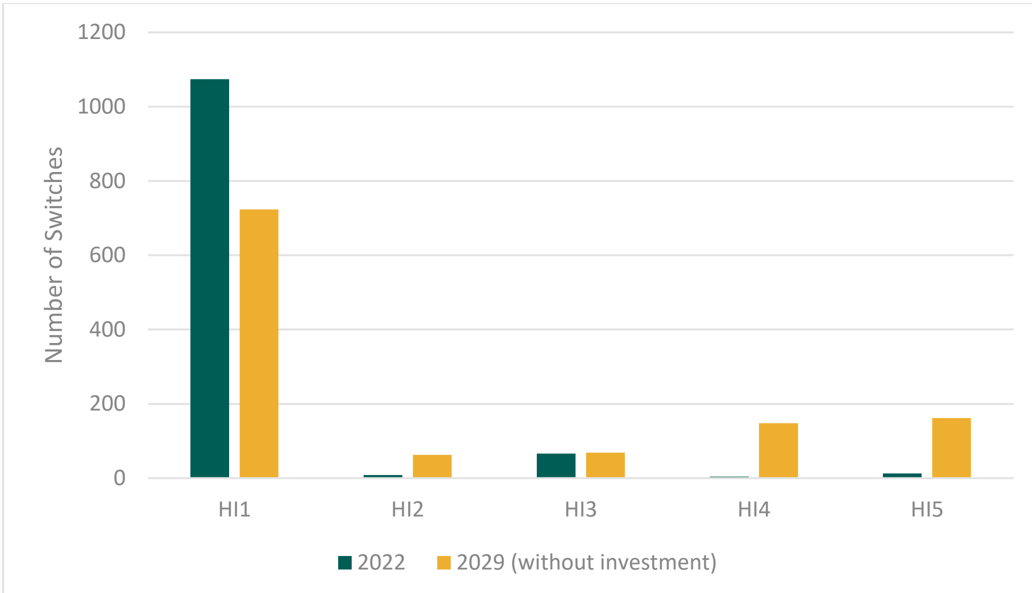


Figure 25: Condition of Overhead SCADA-Mate Switches in 2022 and 2029 (without investment).

E6.5.3.2 Overhead Infrastructure Resiliency

The objective of the Overhead Infrastructure Resiliency segment is to mitigate reliability and safety risks by targeting overhead infrastructure assets that are particularly vulnerable to outages and/or challenging to access due to their location or design. The Overhead Infrastructure Resiliency segment is directly responsive to customer priorities indicated in Phase 1 of Toronto Hydro's Customer Engagement by supporting reductions in the number of outages and restoration time in extreme weather.[25]

Targeted assets include overhead feeders with a history of outages due to weather-related events, tree and animal contacts, and foreign interference. They also include overhead infrastructure assets that are part of functionally obsolete designs, which are no longer aligned with Toronto Hydro's current planning and work practices, but which are not currently addressed through other capital programs. Toronto Hydro plans to mitigate safety and reliability risks associated with these feeders by relocating the existing overhead infrastructure to locations that are more accessible to Toronto Hydro crews and that lower the likelihood and impact of failure.

The primary activities in this segment are:

[25] *Supra* note 8.

1. Undergrounding of overhead assets that have a history of poor reliability (in the form of sustained or momentary outages) due to weather, tree, animal, or foreign interference related outages.
2. Relocation of overhead assets that are in areas with limited or difficult access, and along main arterial rail corridors.
3. Relocation of congested station egress assets with three or more circuits on the same pole.

This segment will mainly target the trunks of feeders as outages on trunks have a higher impact on customers. Trunks are the main sections of feeders exiting from the transformer station and laterals are the branches that come off the trunks and are protected by fuses. Figures 26 and 27 show the CI and customer minutes out ("CMO") impacts of outages due to adverse weather, tree contacts, and foreign interference over the last 5 years, broken down between trunks and laterals of feeders targeted in this segment.

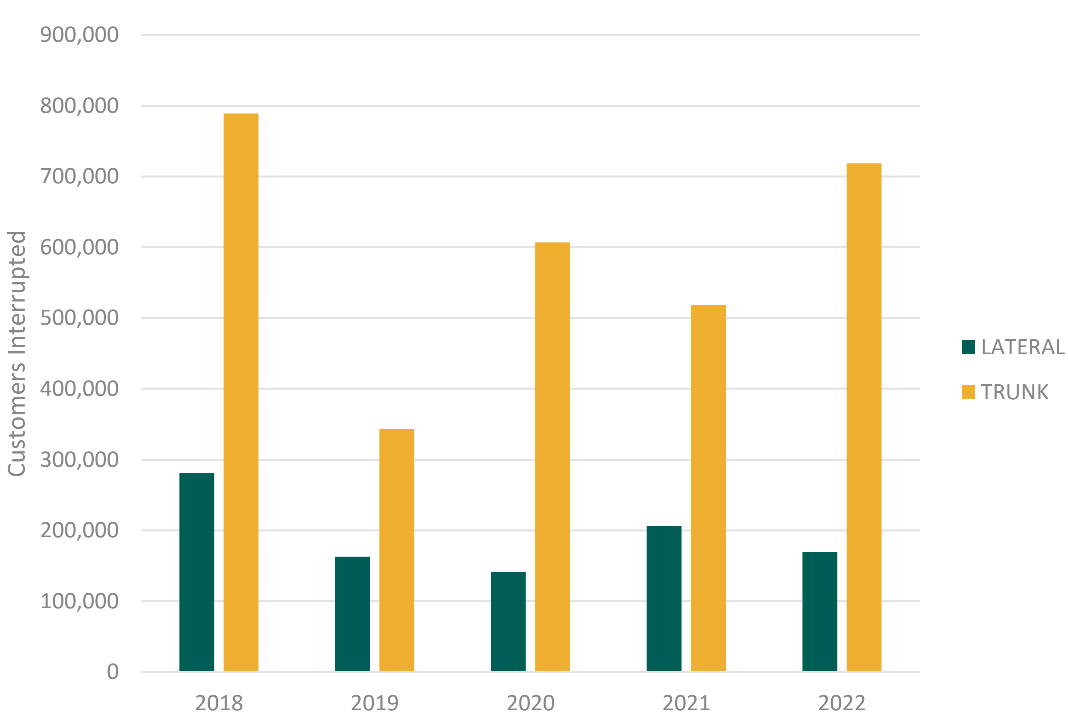


Figure 26: Total Customers Interrupted (CI) – Trunk Versus Lateral

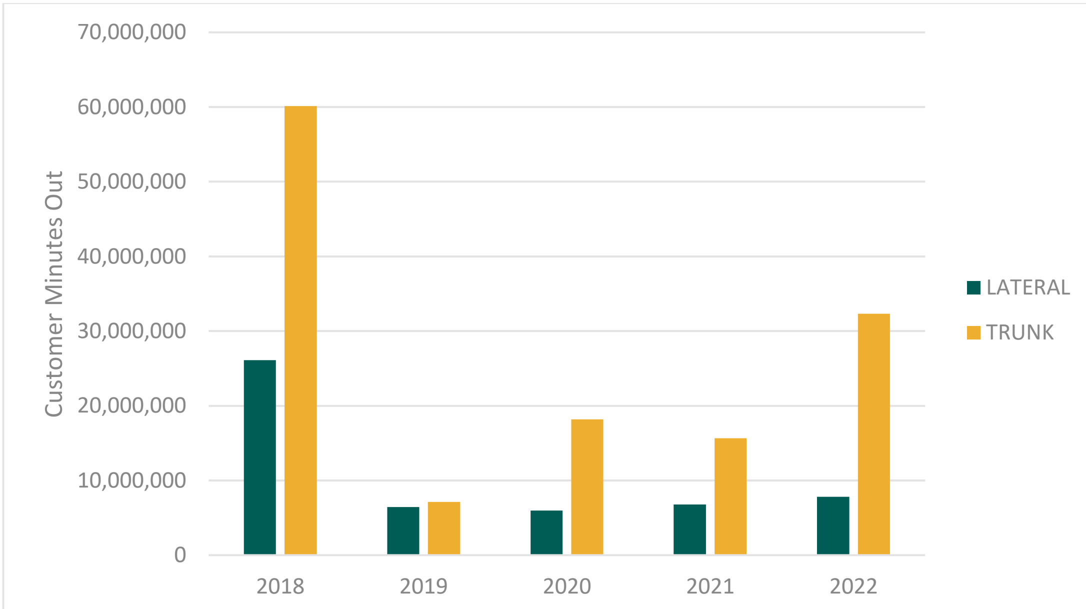


Figure 27: Total Customer Minutes Out – Trunk Versus Lateral

Additional details on the specific types of work and assets targeted in this program are provided below.

1. Overhead Feeders Based on Reliability History

The first category targeted through this segment is overhead feeders which are particularly susceptible to outages due to tree contacts, extreme/adverse environmental or weather factors, and foreign interference. Adverse weather factors include rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions. Adverse environmental factors refer to distribution assets being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, or fire.

Toronto Hydro has identified vulnerable overhead feeders based on the number and duration of outages related to these external factors, as shown in Figure 28 below. Toronto Hydro will target feeders with the greatest number of outages and highest customer hours interrupted as they are likely to benefit the most from being moved underground. By strategically undergrounding overhead sections of these feeders the utility will mitigate the frequency and impact of outages on affected customers, especially as adverse and extreme weather events become more frequent due to climate change.

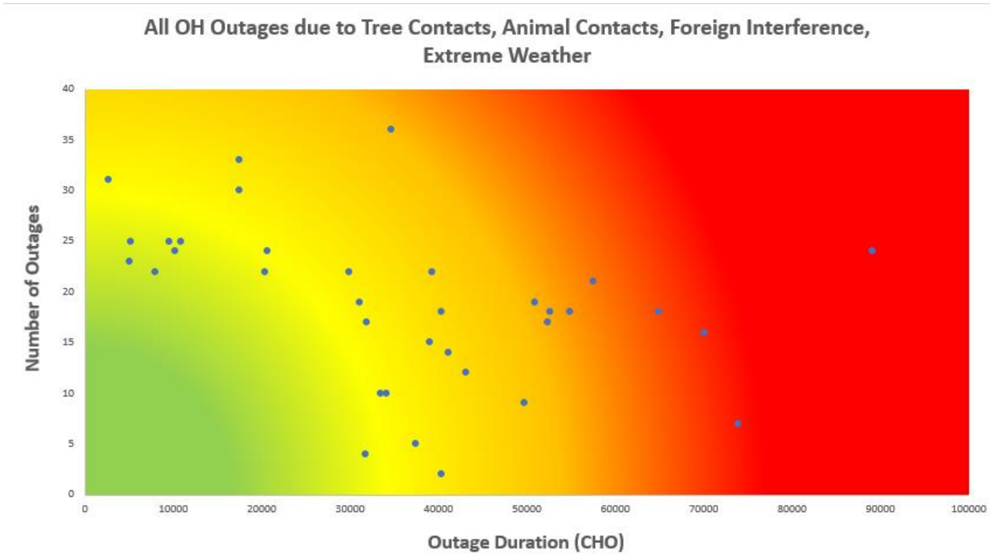


Figure 28: Overhead Outages due to Tree Contacts, Animal Contracts, Foreign Interference and Extreme Weather

2. Overhead Assets in Difficult to Access Locations

Overhead assets in certain parts of the city are located in areas that are difficult for Toronto Hydro employees to access for regular maintenance or for reactive repair or replacement. Figure 29 shows the locations of such assets. These locations can be especially vulnerable during major storm events such as heavy rainfall, floods, and ice storms and make restoration efforts following such events extremely challenging.

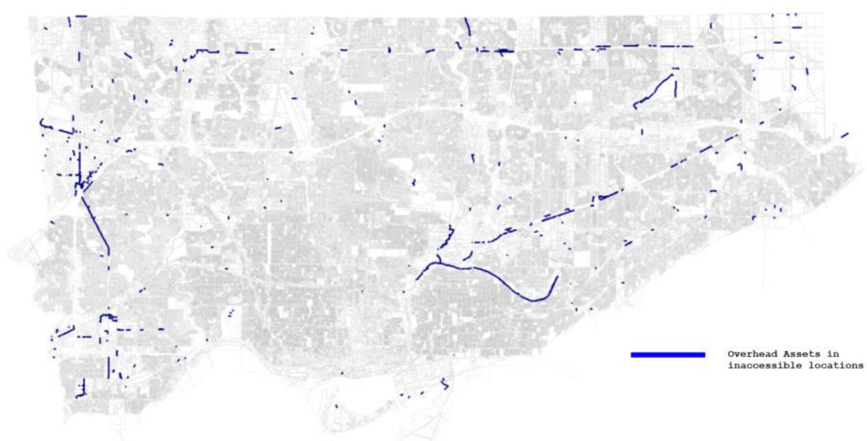


Figure 29: Overhead Assets in Inaccessible locations

Figures 30 and 31 show an example of difficult-to-reach assets. The red line in Figure 30 traces the path of three in-service feeders running through the Humber River in Etobicoke across Kipling Avenue, where access is limited. The poles carry one 27.6kV circuit feeder from Rexdale TS and two 4.16kV circuits from Watercliffe MS.

Figure 30: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue

Figure 31: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue

Another example is shown in Figures 32-33 where the two major circuits (traced in red) from Horner Transformer Station are on the Hydro One right of way ("ROW") and in a rail corridor. Access to these assets requires coordination with CN/CP Rail at all times, even in emergency conditions due to the safety requirement for a flag person from CN/CP authorities. Therefore, these circuits are deemed difficult to access and hence will be targeted for relocation and/or storm hardening.

Figure 32: Overhead Assets in Rail Corridor

Figure 33: Overhead Assets in Rail Corridor

Toronto Hydro plans to reconfigure the feeders and relocate these assets away from the ravines and right of ways to improve accessibility for Toronto Hydro crew members and reduce vulnerability to outages in adverse weather conditions. This will reduce safety risks, such as slips, trips, or fall hazards due to uneven terrain and by enabling the use of bucket trucks instead of having to climb poles to perform certain activities. When climbing poles to work on energized lines, crews may not have bucket truck and equipment access, increasing the risk of coming into contact with live lines. The use of a bucket trucks is the most secure way for crews to reach the assets located on poles since the crews will be working on a stable and insulated aerial device. In general, the reconfiguration and relocation will reduce restoration times in the event of an outage.

Toronto Hydro will relocate these hard to access pole lines, including primary conductors, poles, insulators, transformers, switches and other associated overhead assets and replace them with new construction located in more accessible areas, e.g. overhead distribution on nearby roadways, underground distribution on boulevards, or ducts on bridges.

3. Congestion of Overhead Circuits Exiting from Transformer Stations

The initial section of a feeder exiting a transformer station extends to the first switching point or switchgear. This section is the ‘egress’ and it is a critical portion of the feeder because it carries the entire feeder load. Hence any failure or fault on an egress will result in an interruption to all of the customers on that feeder. If these egress sections are overhead, then they are also exposed to a wide variety of external factors that can cause interruptions, such as adverse weather, tree contacts, and foreign interference.

Toronto Hydro has determined that a single pole carrying three or more feeder egresses (three or more circuits) represents an unacceptably high level of risk to reliability due to the amount of load connected in a single physical location. Should a failure occur that impacts the pole line, three or more feeders could experience an outage, resulting in an unacceptably high number of customer interruptions. The risks are further exacerbated where the circuits on the same pole line are back ups to each other and hence a failure will result in a lengthy outage as restoration may not be possible immediately due to the coincident failure of the back-up feeders.

Through this segment, Toronto Hydro plans to reconfigure these assets such that there are no more than two feeders on a pole line. In some cases, this will involve replacing overhead egress with new underground tree-retardant cross-linked polyethylene (“TR-XLPE”) cable in concrete-encased conduit. The circuit will be underground from the circuit breaker to a point where it can return to overhead.

Figure 34 identifies the transformer stations with pole lines containing three or more circuits that Toronto Hydro will begin to target over the 2025-2029 period.

Figure 34: Transformer stations identified with 3 or more circuits

E6.5.4 Expenditure Plan

Table 6 provides the actual (2020-2021), Bridge (2022-2024) and Forecast (2025-2029) expenditures for the Overhead System Renewal program.

Table 6: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6
Total	36.1	38.2	38.2	32.5	73.9	50.5	60.8	77.4	85.2	84.5

E6.5.4.1 Overhead System Renewal Expenditure Plan

Table 7 below provides the actual, bridge, and forecast costs for the Overhead System Renewal segment. Toronto Hydro invested $112.6 million in the Overhead System Renewal segment between 2020 and 2022, and expects to invest another $106.3 million by the end of 2024. Tables 8 below shows the actual and forecast volumes of assets replaced over 2020-2024. The level of spending and overall unit volumes are both lower than forecast in the 2020-2024 DSP ($265.7 million and e.g. over 11,000 poles) as Toronto Hydro reduced the segment budget to support meeting overall capital funding limits[26] and faced supply chain challenges and other pressures impacting pacing and costs. The utility has been prioritizing replacement of overhead transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, supply chain challenges in acquiring sufficient transformers have reduced Toronto Hydro's ability to ramp up the pace of replacements as intended. The utility has been working diligently to mitigate the impacts of supply chain issues[27] and expects to increase the pacing towards the end of the rate period.

Table 7: Historical & Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9

Table 8: 2020 – 2024 Overhead Asset Replacement Volumes

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Poles	1,418	1,263	1,137	790	2,674	7,282
Transformers	401	584	579	215	1,892	3,671
OH Switches	185	290	71	43	114	703
Conductors* (km)	53.0	60.0	76.0	4.8	45.1	238.8

*Primary cables only

Other factors that can impact project timelines and costs include changes in scope requiring additional work, for example a collapsed duct needing to be repaired.

[26] Exhibit 2B, Section E4.
[27] Exhibit 4, Tab 2, Schedule 15.

Toronto Hydro forecasts spending $272.5 million on the Overhead System Renewal segment over the 2025-2029 period to achieve its goal to generally maintain asset condition and failure risk on the overhead system at current levels and eliminate the last of the overhead transformers at risk of containing PCBs. This includes the cost of replacing end-of-life assets and converting the 4.16 kV or 13.8 kV distribution system to standard 27.6 kV lines. In determining the appropriate pacing, Toronto Hydro carefully considered feedback from customers through the Customer Engagement process to ensure a balanced investment approach to the overhead system renewal portfolio: ensuring reasonable rates but also maintaining reliability. The 2025-2029 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the same period, as shown in Table 9.

Table 9: 2025-2029 Volumes (Forecast): Overhead System Renewal

Asset Class	2025	2026	2027	2028	2029	Total
Poles	2,113	1,556	1,556	1,556	1,556	8,337
Transformers	1,232	907	911	908	889	4,847
OH Switches	123	91	91	104	102	511
Conductors* (km)	66	49	49	45	44	253

**Primary cables only*

The 2025-2029 forecast volumes are high level estimates based on a preliminary selection and scoping of areas targeted for complete rebuilds and spot replacements. Complete rebuilds include: replacing pole lines, overhead transformers and switches; upgrading associated overhead accessories; and re-stringing new conductor. Some of these areas are currently supplied by 4.16 kV and 13.8 kV systems, which will be converted to 27.6 kV through these projects. Once high-level project scopes are produced, Toronto Hydro performs field inspections to validate the scope of work, identify third party conflicts and refine estimates before final design is completed. Through this process, projects identified for renewal are subject to change. For instance, poorly performing feeders that demonstrate higher risks than originally anticipated may take priority.

The 2025-2029 program incorporates the three approaches described below.

- **Feeder Rebuild:** Rebuild of 27.6kV feeders in areas with poor reliability and high concentrations of assets in deteriorated condition that do not require voltage conversion.
- **Voltage Conversion Rebuild:** Voltage conversion of 4kV or 13.8kV to 27.6kV feeders in areas with poor reliability and high concentrations of HI4 and HI5 condition poles. Voltage

conversion requires that all poles, transformers, switches and conductor in each conversion area be replaced.

- **Spot Replacement**: Spot replacement of transformers containing (or at risk of containing) PCBs and the worst condition poles not targeted through the first two approaches.

Once Toronto Hydro has removed all transformers containing PCBs, it will shift towards a more rebuild-focused approach to overhead asset renewal, limiting spot replacements to only the worst condition poles not addressed elsewhere. The rebuild approach is intended to minimize supply disruptions to customers where possible. Reduced disruption to feeders translates into fewer outages for customers and improved project efficiencies. Another way Toronto Hydro maximizes efficiency and cost savings during project planning is by breaking large overhead rebuild projects into smaller phases for enhanced manageability and coordination, providing greater flexibility for scheduling and assigning resources. This approach also reduces the number of scheduled outages and disruptions that customers will experience.

In addition, Toronto Hydro will coordinate any voltage conversion overhead work with related Municipal Stations renewal work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major renewal investments at those stations. Furthermore, the utility needs to strategically and systematically plan conversion work to ensure that the overall 4 kV or 13.8 kV system is still fully functional while the conversion is ongoing. There are additional cost savings and functional benefits from voltage conversions, including that the 27.6 kV distribution system transports more power over longer distances at lower losses (i.e. lower voltage drop at greater distances and improved power quality and distribution efficiency) than the existing 4.16 kV or 13.8 kV systems. This also results in fewer required Municipal Stations, leading to fewer assets to maintain, lower expenditures and greater reliability.

E6.5.4.2 Overhead Infrastructure Resiliency Expenditure Plan

Table 10 below provides the forecast costs for the Overhead Infrastructure Resiliency segment. There are no historical (2020-2022) or bridge (2023-2024) expenditures associated with this segment.

Table 10: Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6

Over 2025-2029, Toronto Hydro plans to spend $85.9 million to target overhead assets for relocation or undergrounding to mitigate reliability and safety risks and improve resilience. The focus of this segment is on very specific and particularly vulnerable sections of the overhead system only, such as those identified in Figure 35 below.

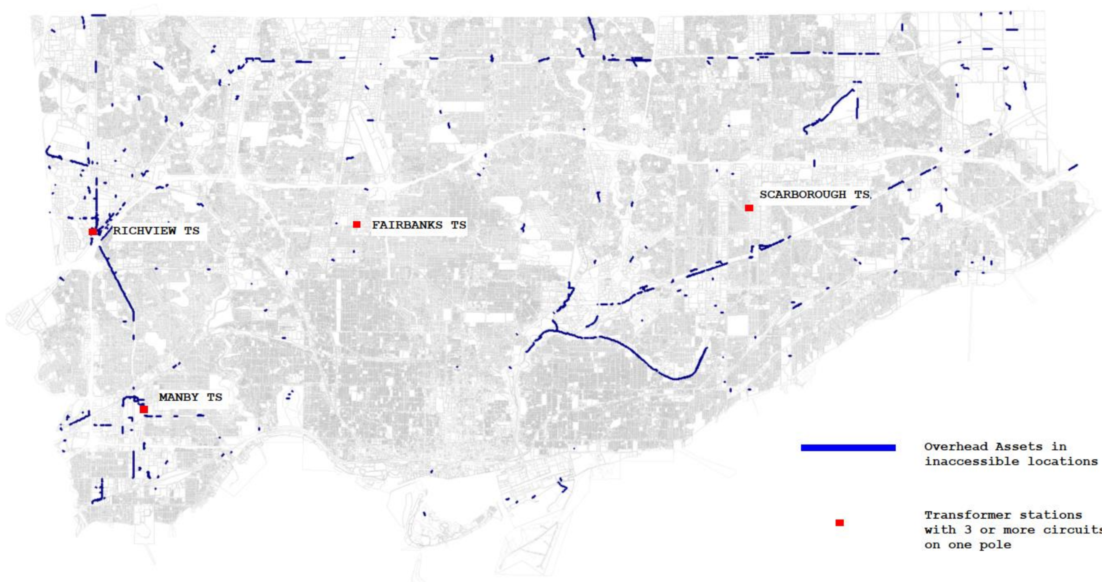


Figure 35: Potential Locations Targeted for Overhead Resiliency Investments

Toronto Hydro plans to target overhead areas which fall under the criteria described in Section E6.5.3.2: i) feeders with history of outages caused by external factors such as adverse weather; ii) feeders in hard to access locations; and iii) egress pole lines with three or more circuits. The utility will prioritize the highest risk areas based on the number of circuits, number and types of customers (e.g. whether includes key account customers), and potential impact to reliability.

The total number and timing of the areas targeted will depend on the specific locations and required scope and level of investment for projects selected (which have not yet been determined). Toronto Hydro has experience completing similar projects in the past, which it has used to inform the planned expenditures in this segment.

For example, in 2019-2020, the utility executed a project along Carlingview Drive between Dixon Road and Meteor Drive. The objective was the targeted undergrounding of two overhead 27.6kv circuits and two 13.8kv circuits, which were experiencing conductor galloping from the wind caused by airplanes landing at Pearson airport. This project undergrounded approximately 1 circuit-km of overhead feeders, installing 7 overhead switches, 5 padmount switches, 2 overhead transformers, approximately 16 km of cables (primary and secondary), 14 poles, and 9 cable chambers. The civil work cost $2.3 million and the electrical $3.5 million, which would be equivalent to approximately $3.1 million and $4.3 million in 2026.

E6.5.5 Options Analysis

E6.5.5.1 Options for Overhead System Renewal

Toronto Hydro considered the following options for the Overhead System Renewal segment. Under each of these options Toronto Hydro would seek to replace all remaining overhead transformers containing, or at risk of containing, PCBs by the end of 2025.

1. **Option 1: Limited rebuild/renewal of extremely poor reliability segments, voltage conversion of 36 Feeders and spot replacement of transformers, poles & switches in deteriorated condition, at or beyond their useful life**

Under this option, Toronto Hydro would prioritize and replace only overhead transformers, poles and switches in deteriorated condition that are at or past useful life. The utility would only rebuild or renew limited overhead assets (transformers, poles and switches) on the worst performing feeder segments and do voltage conversion of select areas that meet poor reliability criteria.

This option would provide minimal improvement in limited circumstances where only a limited number of assets on feeder segments that are in poor condition are replaced and eliminating these assets improves overall feeder performance. Under this option, the utility projects that the System

Health (percent of wood poles in HI4 or HI5) of the wood pole population would increase to 20.5 percent by 2029, even when considering the estimated impact of reactive replacements at a rate of 200 poles per year. The reduced pace of renewal in this option would expose the overhead distribution system to a higher risk of asset failure leading to deteriorating reliability and safety to utility workers and the public. As a result of this approach, Toronto Hydro would likely incur higher reactive repair costs, potentially with greater disruptions to the public and customers in the course of reactive repair work and could face a growing backlog of overhead assets at high risk of failure beyond 2029. Therefore, this option is not recommended.

2. Option 2 (Selected Option): Proactive rebuild/renewal of priority areas exhibiting degradation or poor reliability, voltage conversion of 48 Feeders, and spot replacement of higher risk transformers (PCB only) and poles.

This option proposes a rebuild or renewal of assets on feeders or geographical areas showing signs of degradation or progressively deteriorating reliability, and voltage conversion of functionally obsolete 4.16 kV or 13.8 kV primary voltage designs to 27.6 kV. Specifically, this option will include:

- Full rebuild of areas with poor reliability and a high volume of deteriorated assets beyond their useful life;
- Full rebuild and voltage conversion of 48 select feeders supplied by 4.16 kV or 13.8 kV primary voltage; with a history of poor reliability and a high concentration of assets beyond their useful life; and
- Like-for-like spot replacement of poles and associated overhead accessories showing material deterioration.

Toronto Hydro projects that under this option the System Health of the wood pole population would increase to 18.4 percent by 2029, assuming 200 HI4 and HI5 poles are replaced reactively each year (average over recent years). This is worse than the current system health, but an improvement over Option 1. In selecting this option, Toronto Hydro considered the need to strike a balance between maintaining acceptable safety and reliability on its overhead system, while providing electricity distribution services to customers at reasonable costs. This strategy is in line with Customer Engagement results, which indicate almost equal priority for rates and reliability. Through this option, Toronto Hydro would be best able to manage and mitigate the failure risk of overhead assets (i.e. by removing aged and unreliable assets to address deteriorating reliability), while improving efficiency and capacity of the system (through conversion of 4.16 kV feeders). Furthermore, this option will mitigate the potential accumulation of a large backlog of overhead assets at a high risk of failure and in need of replacement beyond 2029 (which would reduce reliability and increase costs for customers over the long term).

3. Option 3: Replace all assets in deteriorated condition (or beyond useful life) through 27.6kV rebuilds and convert 60 Feeders of 4.16 kV service areas to 27.6 kV

Under this option, Option 2 would be expanded in the following ways:

- Complete a higher number of targeted rebuilds, replacing approximately 12,000 poles, 7,000 transformers and 740 switches.
- Convert 60 4.16/13.8 kV feeders to 27.6 kV supply.

The above would provide additional reliability and other benefits such as improving system efficiency. This option would also ensure Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the overhead system that are supplied by 4.16 kV. This is expected to reduce the number of failures on the overhead system, improve reliability and reduce the spending and resources required for reactive replacements. This option is projected to result in the System Health of the pole population reaching 15.0 percent by 2029. Additional voltage conversion would improve power quality and efficiency, reduce line losses, and accelerate decommissioning of certain municipal stations. However, the financial burden of this option increases dramatically at an estimated total cost of over $350 million.

E6.5.5.2 Options for Overhead Infrastructure Resiliency

1. Option 1: Do Nothing

Under this option, Toronto Hydro would not do any targeted undergrounding or relocation of overhead assets based on historical reliability, location, or design. The distribution system would continue to be prone to increased and prolonged outages on certain feeders due to overhead disturbances and accessibility issues for crews. The safety and operational issues discussed in Section E6.5.3.2, including challenges performing maintenance activities on inaccessible assets, would continue. In some cases, due to the hazards of accessing these locations, feeder outages will be deemed necessary to perform maintenance activities including tree trimming. Additionally, customers on affected feeders would continue to experience longer restoration times than those connected to standard and more accessible feeders.

2. Option 2: Like-for-Like Replacement

Like-for-like replacement would involve the replacement of assets characterized above at their existing locations. Under this option, the probability of failure related to asset age and condition would be reduced, but safety risks related to location would remain. In addition, limited accessibility would continue to impact power restoration times. The overall resiliency of the system would not improve and customers would continue to experience longer than necessary outages. In addition, for most of these cases, a like-for-like option may not be feasible due to the functional obsolescence and non-standard designs of these assets.

3. Option 3: Execute Overhead Infrastructure Resiliency Segment as Proposed

The Overhead Infrastructure Resiliency segment as proposed will directly address the source of specific vulnerabilities on the overhead system, including susceptibility to external factors, such as adverse weather and tree contacts, and functionally obsolete designs, which no longer align with Toronto Hydro's current planning and work practices. This will improve the resiliency of the system and result in improvements to safety and outage frequency and duration.

E6.5.6 Execution Risks & Mitigation

E6.5.6.1 Overhead System Renewal

Large overhead renewal projects can be complicated given that third parties could also be doing work in the same area, resulting in potential conflicts and leading to incremental costs and delays. To ensure effective coordination with the City and other utilities, Toronto Hydro participates in the Toronto Public Utilities Coordinating Committee forum.

Other execution risks associated with large overhead rebuild projects include:

- **Third Party Attachments**: Where third party attachments to Toronto Hydro assets will be affected as part of the project, the relevant owners must be contacted to explore alternative attachment options which may delay the execution timeline. To mitigate this risk, Toronto Hydro will engage owners of these third-party attachment assets as soon as possible to coordinate and plan the required transfer.
- **Permitting**: Delays in obtaining permits from applicable authorities (e.g. the City of Toronto, Ministry of Transportation, CN railways and Hydro One) may require extra design time. To mitigate this risk, additional design time will be built into the schedule to ensure the

necessary permits are obtained without material effect on project schedule. Also, Toronto Hydro will work closely with the City of Toronto on planned road work through meetings of the Public Utilities Coordinating Committee. If work planned by the City puts Program completion at risk, Toronto Hydro will negotiate with the City to coordinate a construction schedule that is acceptable to all parties involved.

- **Operational risks**: Load transfers can be restricted in certain months of the year due to high usage of electricity (e.g. during the summer months). Toronto Hydro will mitigate this risk by scheduling work to avoid periods of loading restrictions.
- **Resource availability**: Insufficient resources and materials can seriously impact project execution, resulting in delays or deferrals into future years. Most recently, there has been an increased risk to the supply chain for acquiring overhead transformers. To address this risk, engineering work plan meetings are held each year to ensure sufficient resources are procured and available to complete the approved projects for that year. When required, short interval control ("SIC") meetings are created for key resources with stakeholders across the organization to manage resources and forecast impact to work programs.
- **Conformance with standards:** Toronto Hydro designs and constructs new overhead rebuild projects in accordance with applicable standards and specifications that are intended to ensure public and employee safety. However, unique situations can sometimes arise to hinder design or construction in compliance with applicable standards. Identifying and making efforts to accommodate and address these issues during the planning and design stages can mitigate most of these risks. Toronto Hydro has established processes to address potential deviations from standards to ensure that the design and construction processes are not delayed and that any accepted deviations from standards do not impact the utility's ability to remain compliant with applicable requirements (including Ontario Regulation 22/04 - Electrical Distribution Safety).[28]

E6.5.6.2 Overhead Infrastructure Resiliency

Execution risks associated with overhead infrastructure resiliency projects include:

- **Third Party Coordination**: Road moratorium imposed by the City of Toronto (third party utilities) may affect areas where Toronto Hydro intends to relocate overhead assets

[28] Ontario Regulation 22/04 – Electrical Distribution Safety, under the *Electricity Act, 1998, S.O. 1998, c. 15, Schedule A.*

underground. To mitigate this risk, Toronto Hydro will coordinate with the City and identify potential conflicts and work around them or develop solutions for execution.

- **Access Issues**: Under this segment, Toronto Hydro will be targeting some assets specifically because they are located in areas with significant access challenges and associated crew safety issues, such as valleys and ravines. Toronto Hydro cannot use its usual equipment (e.g. bucket trucks) to execute this work and therefore will work to ensure that proper pre-job planning, training, and coordination is completed.
- **Operational Constraints and Project Coordination**: When replacing congested egress cables, the entire load of the egress section being worked on needs to be transferred to other feeders. Load transfers can be restricted in certain months of the year due to high usage of electricity, for example during the summer. Overloading feeders can cause equipment deterioration due to heat generated by losses that can result in deterioration of the insulation material, transformers and others. Toronto Hydro will mitigate this risk by scheduling the work where loading restrictions are low, coordinating with customers to avoid conflicts with their specific needs (e.g. school class times, facility production schedules).

E6.6 Stations Renewal

E6.6.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 175.4	**2025-2029 Cost ($M):** 282.7
Segments: Transformer Stations, Municipal Stations, Control and Monitoring, Battery and Ancillary Systems	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Public Policy Responsiveness, Operational Effectiveness - Safety, Environment	

The Stations Renewal program (the "Program") manages station-level failure risk through the replacement of end-of-life and obsolete assets, and manages investments to modernize Toronto Hydro's substations. Customers have indicated that rates, reliability, and prudent modernization are their top priorities. Therefore, the proposed Program has been planned to meet two objectives: first, to maintain station reliability; and second, to replace the majority of Toronto Hydro's obsolete electromechanical relays with modern digital relays.

The failure of station assets can result in power outages for thousands of customers lasting several hours or more, and replacing station assets requires significant lead time. For example, TS Switchgear replacements require years to plan and complete. Hence, to meet customer expectations for reliability, Toronto Hydro proposes the proactive renewal of its station assets at a pacing set to maintain their reliability. This pacing is being proposed to balance the priorities of rates with station reliability. Toronto Hydro prioritizes station assets for proactive renewal based on their age, condition, performance, load served, and customers connected.

By the end of 2023, 43 percent of Toronto Hydro's station relays will be technically obsolete electromechanical relays, which do not permit event reporting, fault diagnostics, or power flow observability. Additionally, these obsolete relays have limited functionality to detect and discriminate between more complex faults that can lead to misoperation. The features of modern digital relays are needed to support Toronto Hydro's grid operability and evolution towards a smart grid infrastructure that integrates vehicle-to-grid, peak shaving, and increased distributed energy resource penetration.

The Program is grouped into the four segments summarized below and is a continuation of the station renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Transformer Stations ("TS"):** This segment involves the renewal of Toronto Hydro's TS switchgear, outdoor breakers, and outdoor switches located at TS. Replacing station assets that have deteriorated and are beyond their useful life allows Toronto Hydro to sustain reliability and mitigate crew exposure to safety hazards. TS assets supply commercial, industrial, and key account customers who are highly sensitive to power outages and power quality issues. During the 2025-2029 period, Toronto Hydro plans to replace three TS switchgear, complete four TS from the 2020-2024 period, 12 TS outdoor breakers, and 63 TS outdoor switches. Toronto Hydro also plans to refurbish one station building in preparation for switchgear replacements required over the 2030-2034 period. This segment is estimated to cost $134 million in total over the 2025-2029 period.
- **Municipal Stations ("MS"):** This segment involves the renewal of Toronto Hydro's switchgear and transformers located at MS and their primary supplies. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to maintain reliability, improve worker safety, and sustain the system in the long term. The majority of Toronto Hydro's MS assets serve Toronto's suburban areas which consist largely of residential and general service customers. During the 2025-2029 period, Toronto Hydro plans to replace 12 MS switchgear, 15 power transformers, and one MS primary supply, for a total estimated cost of $70.3 million.
- **Control and Monitoring:** This segment involves the renewal and modernization of protection, control, monitoring, and communication assets at Toronto Hydro's TS and MS. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 rate period, Toronto Hydro plans to renew 33 existing Remote Terminal Units ("RTUs") and replace 251 obsolete relays with modern digital relays, for a total estimated cost of $64.7 million.
- **Battery and Ancillary Systems:** This segment involves the renewal of DC battery and charger systems, station service transformers, and station AC service panels. This segment also installs new systems to mitigate the risk of flooding at targeted stations. During the 2025-2029 rate period, Toronto Hydro plans to replace 55 batteries, eight charger systems, replace

[1] EB-2018-0165, Exhibit 2B, Section E6.6.

three station service transformers, replace five station AC service panels, and install three sump pumps for a total estimated cost of $13.6 million. This work will allow Toronto Hydro to maintain the integrity of its station assets, maintaining reliability outcomes for Toronto Hydro customers.

Toronto Hydro plans to invest $282.7 million in the Stations Renewal Program in 2025-2029, which is a $107.3 million or 61 percent increase over the projected 2020-2024 spending in the Program. This increase is approximately equally split between an increased work volume and forecasted inflation. This level of investment is necessary to address an increasing population of end-of-life and poor condition station assets, address failure risks and trends identified over the 2020-2024 rate period, support Toronto Hydro's grid modernization investments, and prepare Toronto Hydro for continued success in the Program into the following period of 2030-2034.

E6.6.2 Outcomes and Measures

Table 2: Outcomes Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (SAIDI, SAIFI) by reducing the percentage of station assets in deteriorated condition and/or operating beyond their useful life (percentages vary by asset class) • Mitigates failure risks to tens of thousands of customers through renewal work ○ 163,000 customers by replacing assets at and beyond useful life at Transformer Stations (e.g. switchgear, outdoor breakers, outdoor switches); ○ 14,200 customers by replacing assets at and beyond useful life at Municipal Stations (e.g. switchgear, power transformers, primary supplies); ○ 596,690 customers by renewing RTUs, Relays; and, ○ 491,370 customers by renewing DC system and AC station service equipment

Public Policy Responsiveness	• Contributes to Toronto Hydro's Grid Modernization plan by replacing obsolete electromechanical relays with modern digital relays: ○ Accommodate increasingly sophisticated customer needs; ○ Help Toronto Hydro operate its system more efficiently to modernize the grid to allow for better observability and controllability; ○ Allow for fault recording; ○ Provide relay diagnostics for easier maintenance; ○ Better fault coordination; and, ○ Help provide increased value to customers • Increasing the population of station digital relays to 90 percent in 2029
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and worker safety performance, as measured by the Serious Electrical Incident Index and Total Recordable Injury Frequency by: increasing the population of arc-resistant switchgear, and decreasing the population of oil-filled TS outdoor breakers
Environment	• Contributes to Toronto Hydro's environmental stewardship by reducing the number of station assets containing (or at-risk of containing) degraded oil

E6.6.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Public Policy

The Stations Renewal Program addresses failure risk and obsolescence issues associated with Toronto Hydro's critical station assets. A large portion of Toronto Hydro's station assets are operating beyond their typical useful lives and are subject to an increased risk of failure due to their age and condition. Station asset failures have large impacts on system reliability due to the large number of customers served by each station. Necessary repairs are often complex and take significant time to complete.

Like distribution line assets, prudent management of station assets is achieved by monitoring asset demographics and condition. However, management strategies that use run-to-fail or just-in-time asset replacement are generally unacceptable for station assets due to the impacts of failed assets on customers.

In addition to their increasing failure risk, many older assets use technology that has become obsolete due to advancements, emerging industry trends, and evolving best practices related to safety, customer needs, and functionality. Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications) and operate the utility's system more efficiently.

E6.6.3.1 Transformer Stations ("TS")

Toronto Hydro's TS supply power to all customer classes. Major TS assets include TS switchgear, TS outdoor breakers, and TS outdoor switches. A large portion of these assets are operating beyond their useful life and are at a heightened risk of failure. Toronto Hydro uses a risk-based approach to identify the highest priority TS assets for replacement. The utility's asset management objective is to cost-effectively sustain current levels of reliability and prudently mitigate crew exposure to safety hazards.

1. TS Switchgear

As shown in Table 4 below, about a third of Toronto Hydro's TS switchgear will be operating past its useful life by the end of 2024. Many of these assets are non arc-resistant and have other obsolete design features that increase safety risks for crews and the risk of collateral asset damage in the event of switchgear failure.

Table 4: Transformer Station Switchgear Demographics at end of 2024

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	45	40%	73%	7%
Brick Structure	3	100%	100%	100%
GIS	5	0%	0%	0%
Total	53	34%	68%	11%

Toronto Hydro uses asset condition, age, and operational feedback to identify and prioritize the renewal of its switchgear assets. Switchgear are complex assets that include several different parts. Each part has its own failure mode and useful life, which are often less than the 50 years attributed to the switchgear as a whole. Toronto Hydro performs reactive repair and maintenance on individual switchgear parts. This reactive approach becomes less prudent as components that cannot easily be replaced age and deteriorate. Examples include bus bars, bus insulators, and miscellaneous control wiring.

Toronto Hydro assesses the condition of switchgear assets using infrared hotspot scanning, and cable termination, connection, and cleanliness qualitative (visual) assessments. Major components such as breakers are also individually assessed. Toronto Hydro previously used these measurements (excluding the breaker condition assessments) to derive a single health index measurement ("HI") for switchgear. However, the HI reflected a limited number of measurements and made it difficult to balance different indicators. As a result, Toronto Hydro now assesses risk using switchgear age, breaker condition, and operational feedback to evaluate these asset components on an asset-by-asset basis. The current age demographics of Toronto Hydro's TS switchgear units are shown in Figure 1 below.

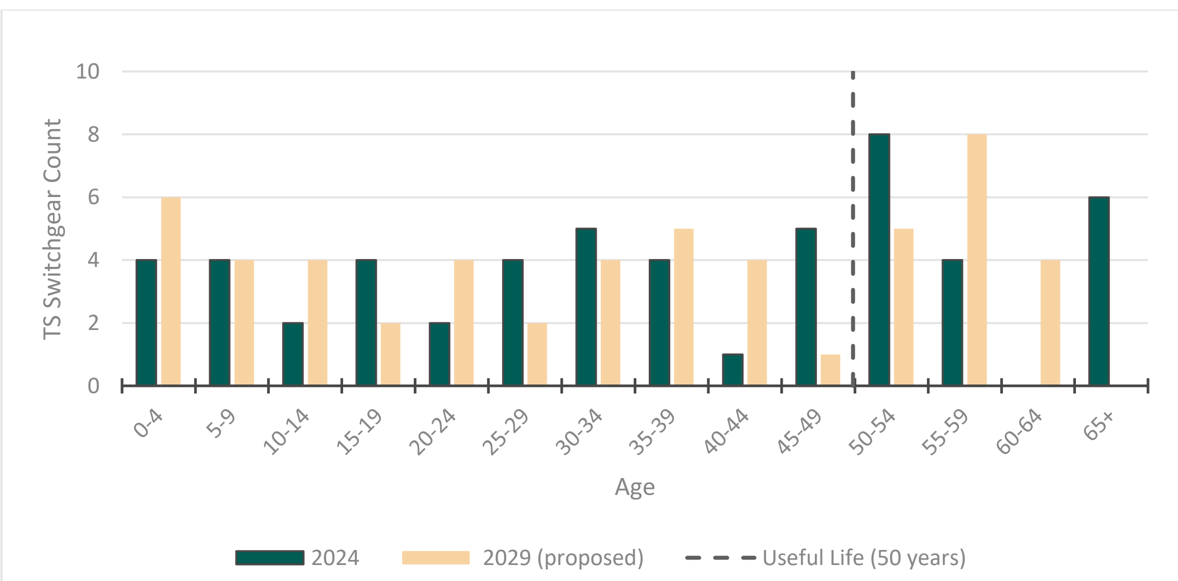


Figure 1: TS Switchgear Age Demographics

As indicated in Figure 1 above, Toronto Hydro anticipates having 18 TS switchgear units operating at or beyond their useful life expectancy by 2024 and 17 units by 2029. Toronto Hydro's condition assessment for all breakers contained within its TS switchgear population is shown in Figure 2 below. A significant proportion of Toronto Hydro's breakers with moderate deterioration or worse are air-blast breakers. These are the oldest breakers in use. The technology is obsolete and it is difficult to obtain parts for maintenance. These breakers are found in 11 of the switchgear units operating beyond their useful life.

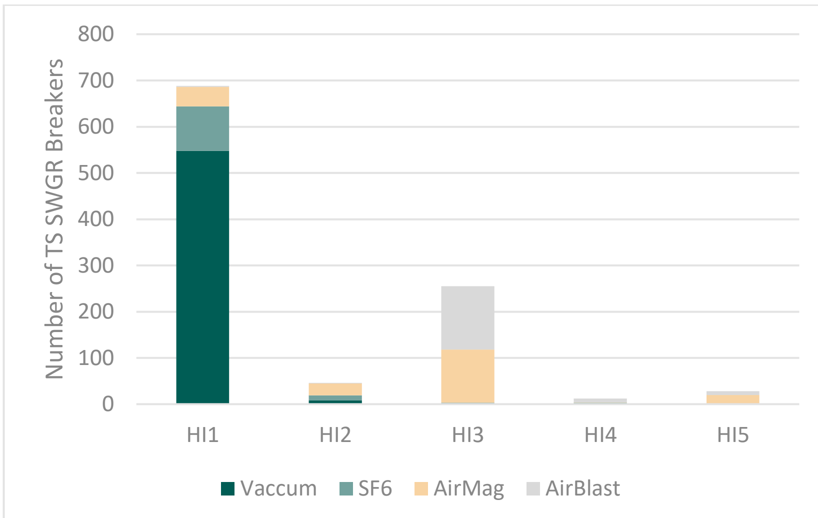


Figure 2: TS Switchgear Breaker Condition by Type as of 2022

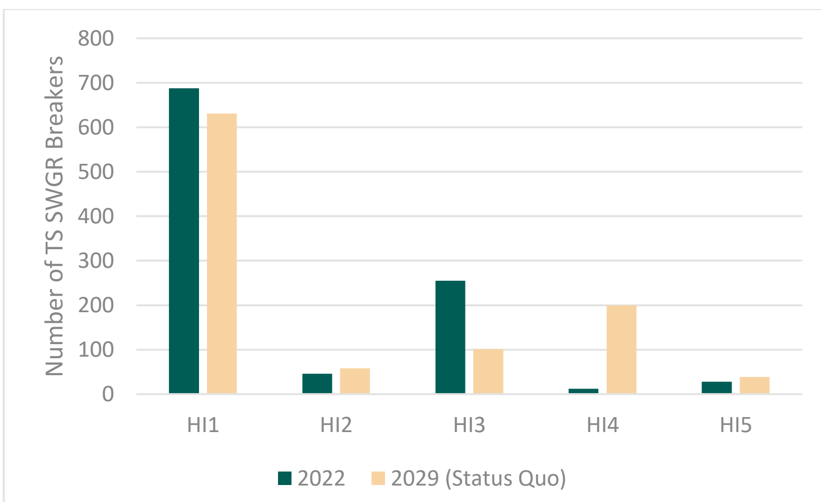


Figure 3: TS Switchgear Breaker Condition Aggregate as of 2022 and in 2029 Without Investment

Switchgear failure has a severe impact on distribution system operations. As one example, a recent failure of a switchgear breaker resulted in a power interruption for 13,152 customers and 10.5 MVA of the bus load. The average affected customer was without power for two hours and it took two and a half hours for the last customers' power to be restored following the failure. A photo of the failed breaker is shown in Figure 4 below. As shown in the photos, visual condition assessment may not always be effective because components are not accessible for the level of inspection required to detect measurable signs of impending failure. This is particularly true for some metalclad switchgears that require a complete switchgear outage to enable a thorough assessment of their condition, which is not possible without significant customer outages. The newer buses address this issue by allowing for efficient load transfers.

Figure 4: Failed Switchgear Air Blast breaker and damaged arcing contacts

Figure 5 below shows the number of bus outages due to failure of TS switchgear components over the last ten years. These include a breaker's failure to open on fault, a failed CT and a failed bus insulator. Investments in asset renewals to maintain TS switchgear components in healthy operational condition are essential for Toronto Hydro to provide its customers with reliable service.

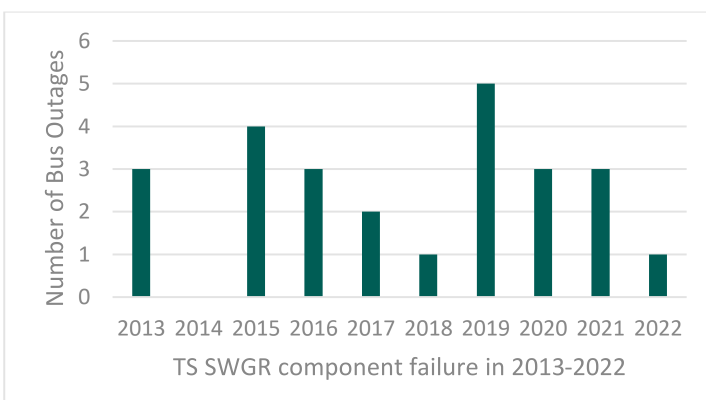


Figure 5: Bus outage caused due to SWGR component failure in 2013-2022

Toronto Hydro's average TS switchgear supplies 37 MVA of load – more than the failure case highlighted above – and its heaviest loaded unit serves 63 MVA of peak load. As shown in Figure 6 below, these assets primarily serve Toronto's downtown and adjacent areas, which include Toronto's financial district, entertainment district, university district, and some of the city's densest residential communities.

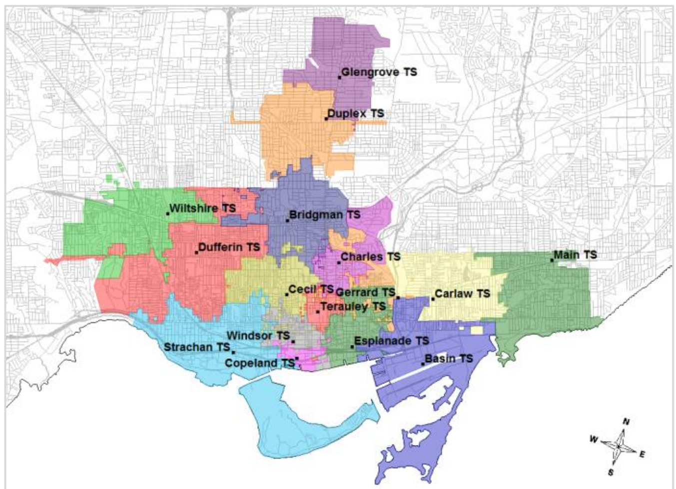


Figure 6: Location of TS containing Toronto Hydro-Owned Switchgear (excluding Cavanagh TS in North Scarborough)

Toronto Hydro proposes to replace the five TS switchgear units identified in Table 5 below during the 2025-2029 period. All of the units proposed for replacement are beyond their 50-year useful life expectancy and feature obsolete circuit breakers contained within non-arc-resistant enclosures. Condition assessments performed during breaker maintenance show that all of the breakers in the switchgear units proposed for replacement suffer from HI4-material deterioration. This is an older air blast type installed in the 1950s that is functionally obsolete. Breakers are used to determine the condition of a switchgear because they are the "moving parts" inside of switchgear and are indicative of a switchgear unit's overall health.

Table 5: TS Switchgear Proposed for Replacement

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Danforth MS	*A1-2DA*	Brick	Air Blast	Material Deterioration	2029
Bridgman TS	*A7-8H*	Brick	Air blast	Material Deterioration	2029
Windsor TS	*A3-4WR*	Metalclad	Air blast	Material Deterioration	2029

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Bridgman TS	*A1-2B*	Metalclad	Air blast	Material Deterioration	2029 (building renovation by Hydro One)

As shown in Table 6 below, with these replacements and investments, by the end of 2029 there will be a decrease in non-arc resistant switchgear units from 68 to 53 percent and a decrease in switchgear units with obsolete breakers from and 11 to 2 percent compared to 2024.

Table 6: Transformer Station Switchgear Demographics at End of 2029 with Investment

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	48	35%	58%	2%
Brick Structure	0	0%	0%	0%
GIS	5	0%	0%	0%
Total	**53**	**32%**	**53%**	**2%**

Figure 7 below shows the volume of customers and quantity of load that will benefit from Toronto Hydro's proposed replacement plan.

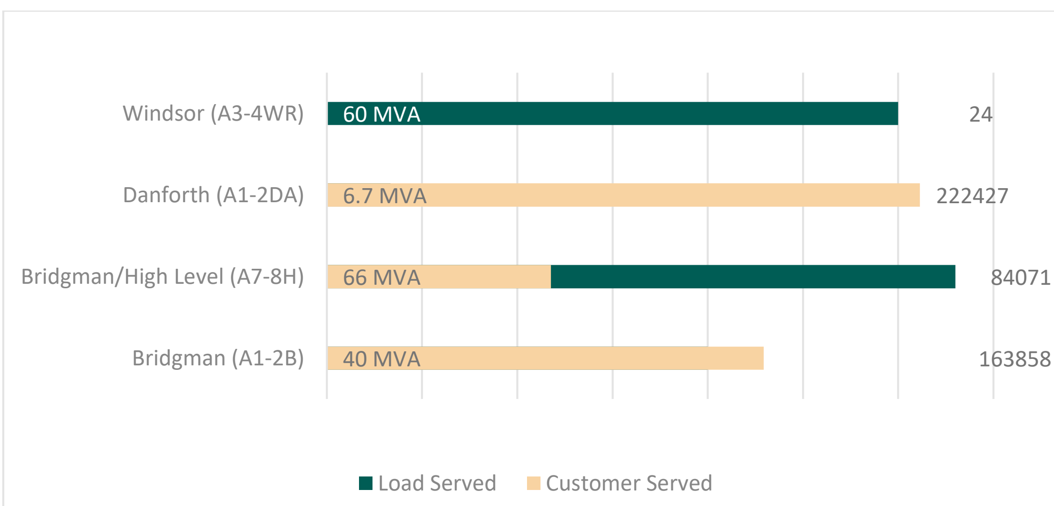


Figure 7: Customer Impact of Switchgear Failure - TS Switchgear Proposed for Replacement

2. TS Outdoor Breakers

As shown in Table 7 below, 13 percent of Toronto Hydro's TS outdoor circuit breakers will be operating past their 45-year useful life by the end of 2024. These breakers (i.e. the KSO oil circuit breakers) are based on obsolete technology and may contain degraded oil, which would increase the safety risk for crews, the risk of collateral damage to other assets, and the risk of environmental damage if a breaker failure occurs. As indicated in Table 7, 100 percent of Toronto Hydro's KSO oil-based circuit breakers will be past their useful life of 45 years by the end of 2024.

Table 7: TS Outdoor Breakers Demographics at the end of 2024

Outdoor Breaker Technology	# of Assets	% of Assets Past Useful Life
KSO Oil Circuit Breaker	12	100%
SF6 Circuit Breaker	24	0%
Vacuum Circuit Breaker	56	0%
Total	92	13%

Figure 8 below compares the condition of the utility's TS outdoor breakers as of 2022 with the condition of the breakers in 2029, in a scenario without investment.

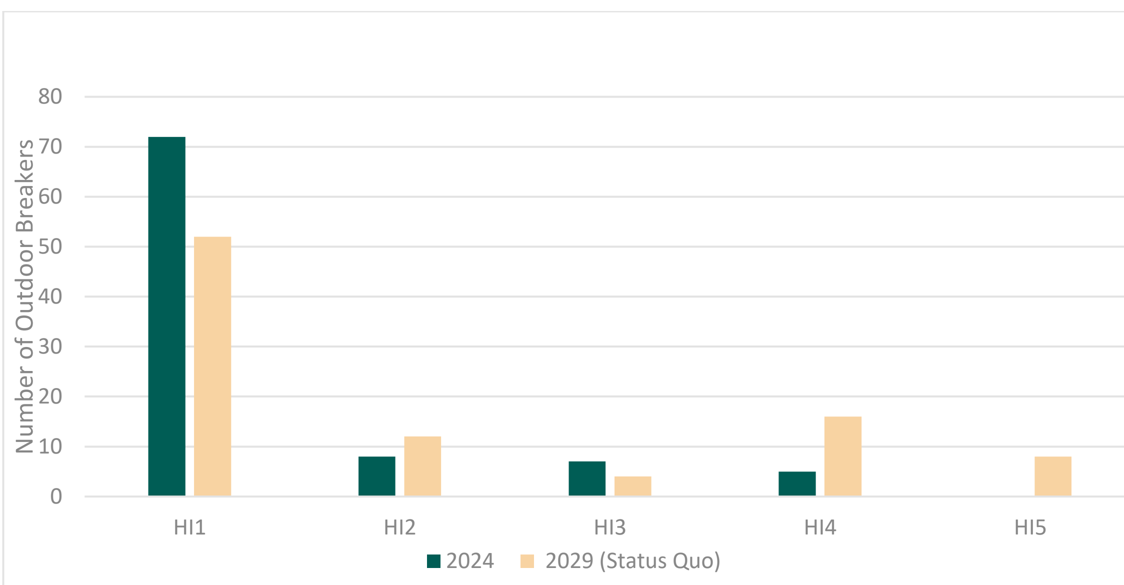


Figure 8: TS Outdoor Breaker Condition as of 2022 and in 2029 without Investment

As of the end of 2022,

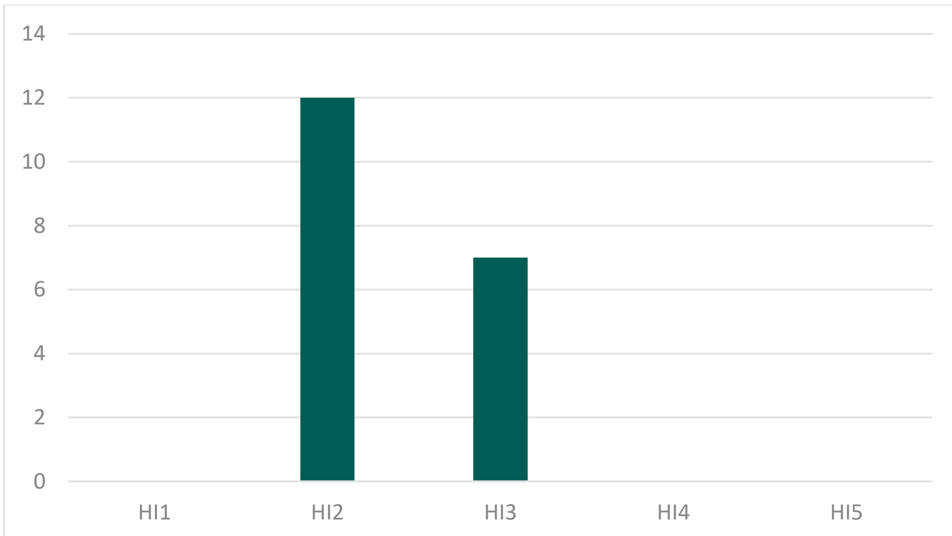


Figure 9 below illustrates the condition of these circuit breakers at the end of 2022 (including the units planned to be replaced in 2023 and 2024).

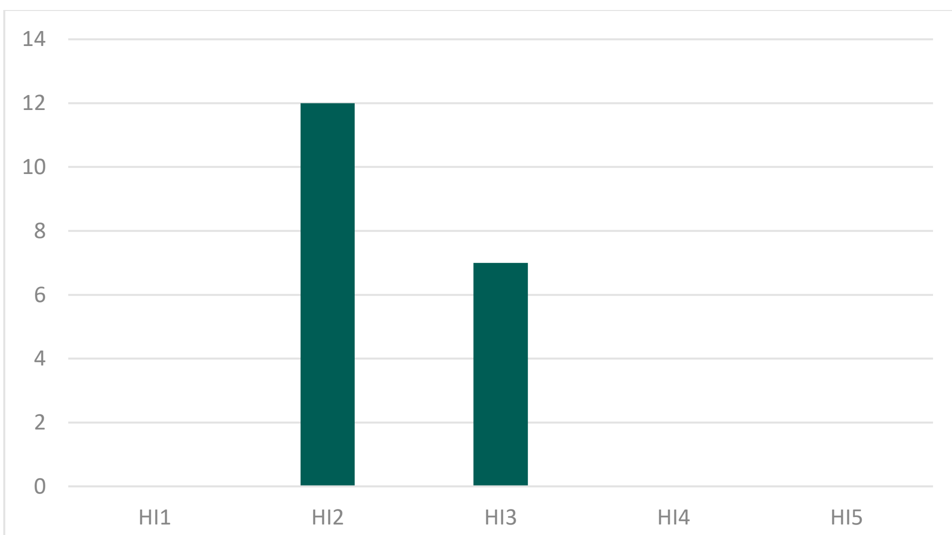


Figure 9: Condition Assessment for KSO Oil Circuit Breakers as of the end of 2022

Toronto Hydro plans to replace all the oil KSO breakers with vacuum breakers by the end of 2029. In order to minimize the outage time for each cell, the relays will be replaced together with the KSO breakers unless cell relays have already been reactively replaced prior.

These investments would enable Toronto Hydro to improve its ability to accommodate new customer connections, including renewable generation or energy storage systems. As such, this work will provide customers with increased reliability and flexibility and will eliminate some of the system's biggest safety and environmental risks.

The failure risk of KSO circuit breakers is high and the impact of failure is significant. When a breaker fails, thousands of customers will experience an outage that typically lasts one to two hours. Circuit breaker failure is most likely to occur when the breaker is triggered to operate. When a circuit breaker fails, the next upstream protection device at the station bus is then triggered to operate. A fault that was otherwise localized on a feeder would then extend to all of the customers supplied by that station bus, potentially disrupting anywhere from 1,000 to 10,000 customers depending on the bus.

Toronto Hydro experienced an outage of this nature when an outdoor breaker at Finch TS failed to open. The bus protection system was forced to operate, interrupting power to nearly 5,000 customers. Most customers were restored within three hours of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the breaker operated as intended.

Beyond the outage impact to customers, KSO oil circuit breakers run the risk of failing catastrophically. In this situation, the circuit breaker explodes and sets fire to its oil, potentially damaging equipment, injuring personnel in the vicinity and impacting the surrounding environment. In addition to heightened safety risk, catastrophic failures also pose the risk of environmental damage due to oil leakage.

To mitigate the reliability and safety risks noted above, Toronto Hydro plans to replace the 12 TS outdoor breakers identified in Table 8 below during the 2025-2029 period. All of the breakers proposed for replacement are beyond their 45-year useful life expectancy and contain or are at risk of containing degraded oil. Toronto Hydro will prioritize the breakers presenting the highest failure risk for work during the 2025-2029 period.

Table 8: TS Outdoor Breakers Proposed for Replacement

Station	Breaker Type	Feeder	Load Served	Replacement Year
Bathurst TS	*KSO Oil Circuit Breaker*	85-M23	33 MVA	2025
Bathurst TS	*KSO Oil Circuit Breaker*	85-M32	32 MVA	2025

Leslie TS	*KSO Oil Circuit Breaker*	51-M22	16 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M29	24 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M30	20 MVA	2027
Leslie TS	*KSO Oil Circuit Breaker*	51-M32	17 MVA	2027
Finch TS	*KSO Oil Circuit Breaker*	55-M31	26 MVA	2028
Finch TS	*KSO Oil Circuit Breaker*	55-M32	25 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M21	12 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M22	13 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M23	19 MVA	2029
Fairchild TS	*KSO Oil Circuit Breaker*	80-M24	18 MVA	2029

With the proposed plan and timeline shown in Table 8, below shows the overall state of all TS outdoor circuit breakers within Toronto Hydro's system along with their status in 2029.

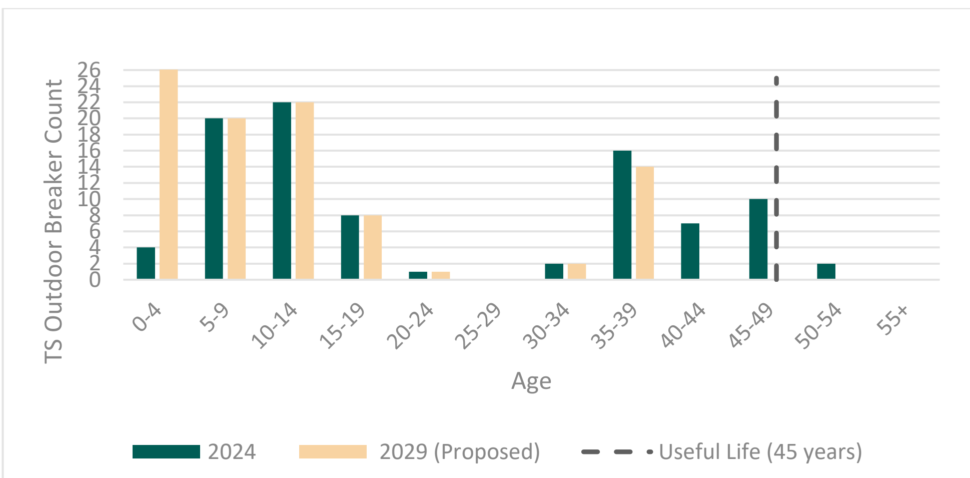


Figure 10: TS Outdoor Breaker Age Demographics at the end of 2024

As per Figure 11, these assets are located at stations serving customers located in the North York area. Once this work is complete, customers and loads connected to these four stations will face reduced risk of power disruptions resulting from breaker failure.

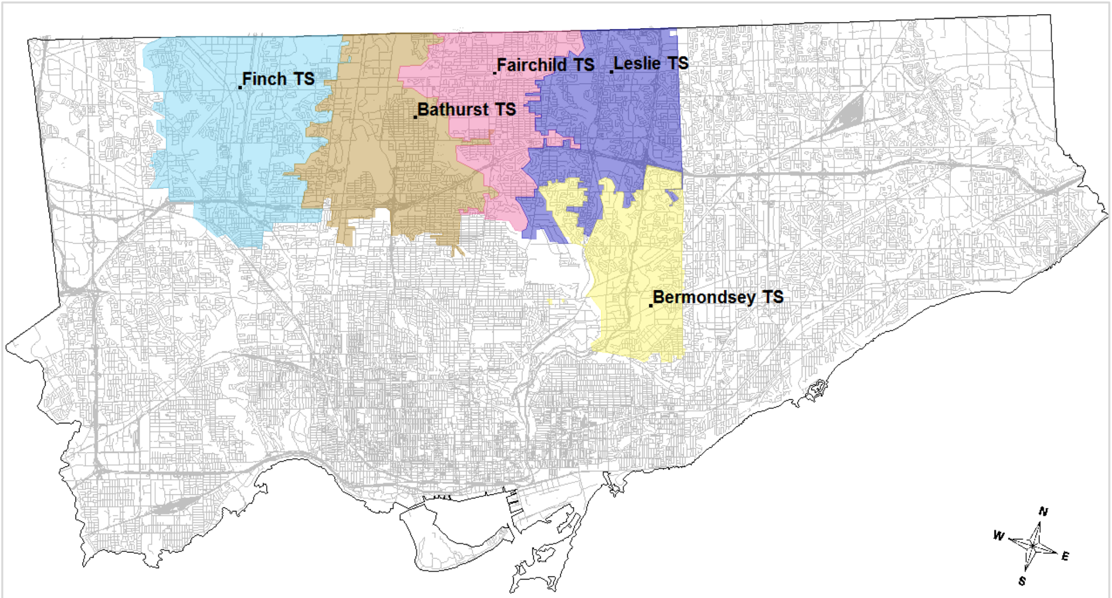


Figure 11: Toronto Hydro-owned TS containing outdoor circuit breakers.

3. TS Outdoor Switches

In addition to owning breakers at the five North York stations identified in Figure 11 above, Toronto Hydro also owns 230 TS outdoor switches located at the same stations. By the end of 2024, 7 percent of these TS outdoor switches will be operating beyond their 50-year useful life. The majority of them have never been replaced since their original switchgear or breaker installations.

Many of these switches have failed in recent years because of their age and deteriorated condition. Personnel have noted difficulty operating these switches, citing that in many cases, excessive force is required to close or open them. This risks damage to the switches and injuries to workers, as difficult to operate switches create safety issues like arc-flash.

Toronto Hydro does not have a Health Index for these switches. Switches are manual devices that either open or close when operated. Therefore, their condition is best captured by relying on visual assessment by Toronto Hydro field personnel and their experiences operating these switches. To increase the reliability of Toronto Hydro's grid system, Toronto Hydro plans to replace 63 TS outdoor switches during the 2025-2029 rate period as outlined in Table 9 below.

Table 9: TS Outdoor Switches Proposed for Replacement

Station	Feeder Tie Switch	Line Disconnect Switch	Total Switches	Replacement Year
Bathurst TS	2	4	6	2025
Bathurst TS	2	4	6	2026
Fairchild TS	3	6	9	2026
Fairchild TS	3	7	10	2027
Finch TS	5	11	16	2028
Leslie TS	5	11	16	2029
Total	**20**	**43**	**63**	

As shown in

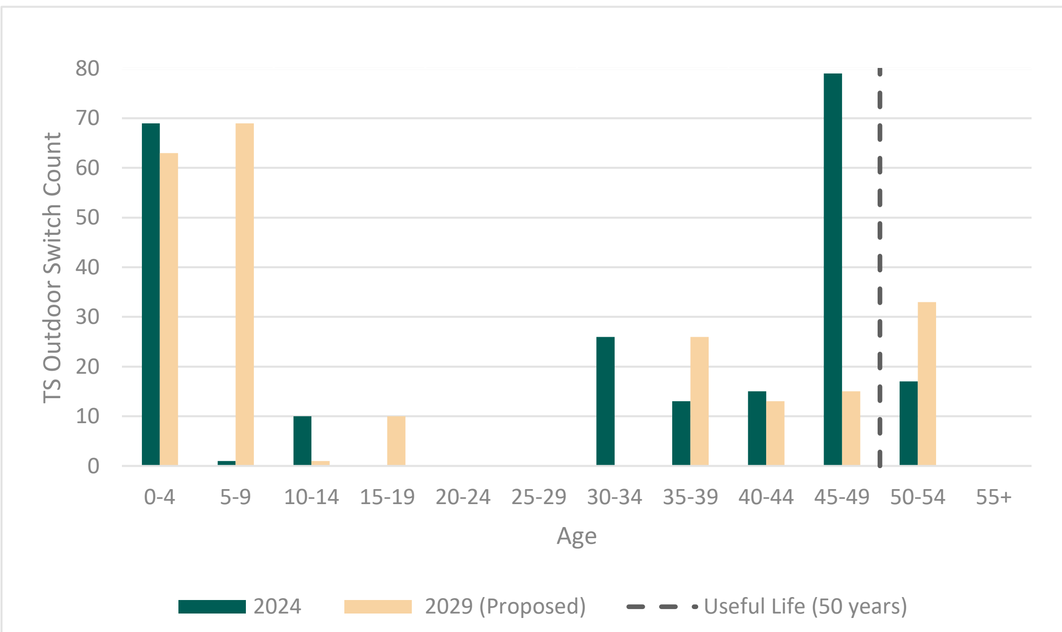


Figure 12 below, 17 of Toronto Hydro's TS outdoor switches will be operating beyond their 50-year useful life by the end of 2024. Without investment, an additional 79 switches will be operating past their useful life in 2029. Without action during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be beyond or within five years of their useful life expectancy by 2029. In order to maintain the condition of its TS switches, Toronto Hydro plans to replace 63 TS outdoor switches. This will reduce the proportion of switches within or beyond their useful life from 40 percent to 20 percent by 2029.

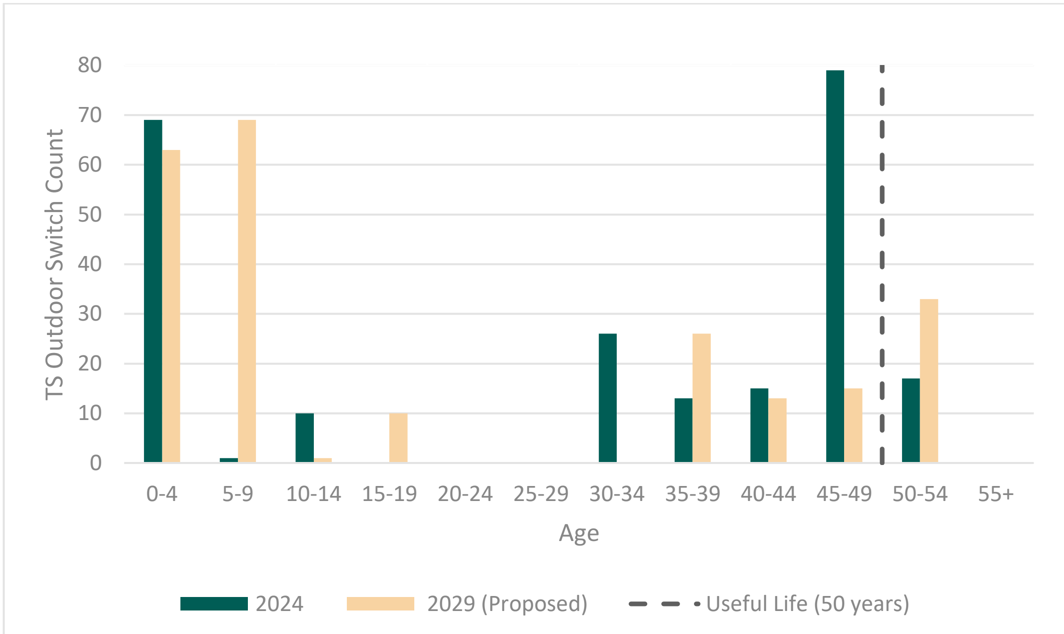


Figure 12: TS Outdoor Switch Age Demographics

Figure 13: Repair of TS Outdoor Switch

E6.6.3.2 Municipal Stations ("MS")

Toronto Hydro's MS supply power to Toronto's suburban areas consist largely of residential and a few small general service customers (<1 MW). Major MS assets include switchgear, power transformers, and MS primary supplies composed of disconnect switches and power cable. A large portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure. The investments proposed under this segment will maintain MS reliability by replacing deteriorated and obsolete assets at MS without upcoming voltage conversion plans.

A given MS supplies hundreds to thousands of customers. All connected customers experience a power outage if any of that MS major assets fail. A power supply must be switched to an adjacent MS in order to restore power to customers. This process typically takes half an hour to six hours. Following this restoration of power, the failed asset is repaired or replaced over a period of weeks or months.

Should an additional failure occur at an adjacent MS, then it is possible that during peak times brown outs (rotating outages) may be imposed on customers until one of the MSs is restored to service. This is because the MS distribution system is not designed to support a MS failure when its backup source is out of service.

For similar reasons, maintenance and renewal work at adjacent MS cannot be overlapped. As the population of MS assets get older without a proper renewal plan, the risk of having an MS failure when its backup source is not available becomes higher. Thus, asset renewal and maintenance plans become more difficult to execute while managing the risk of interrupting service to customers. Where possible, Toronto Hydro coordinates end-of-life asset replacements at a single MS during the same year, rather than having replacements and outages spread over multiple years.

1. MS Switchgear

The useful life of a MS Switchgear is 50 years. All of the MS switchgear targeted for replacement, listed in Table 10, will be between 58-65 years old at their time of replacement. None of them are arc-resistant and they are all equipped with technically obsolete circuit breakers which are no longer supported by manufacturers. One switchgear proposed for replacement utilizes oil circuit breakers, while the rest utilize air magnetic circuit breakers. As seen in Figure 14 below, almost half the population of the MS air magnetic circuit breakers is forecasted to progress to HI4-Material Deterioration by 2029 without investment. Operating these breakers in this condition increases failure risks, which can be mitigated with the proposed replacements.

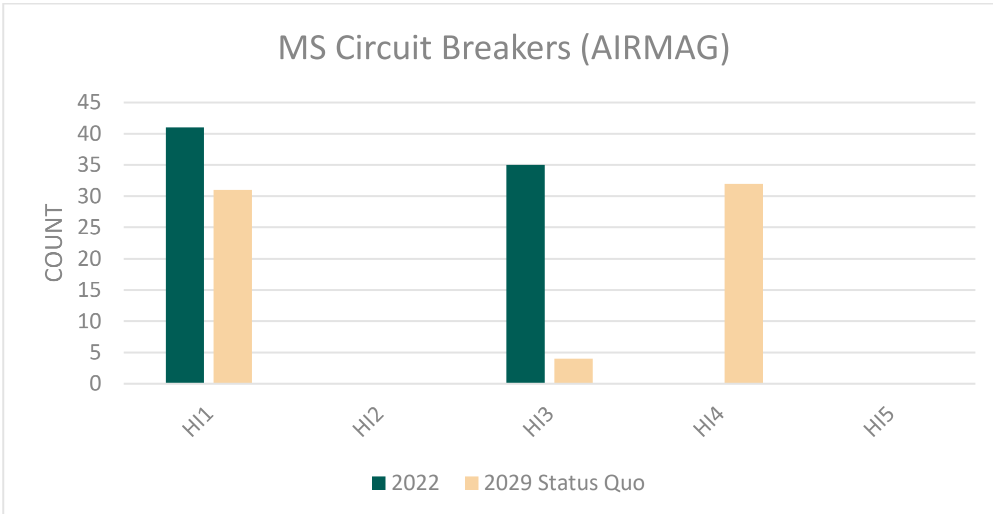


Figure 14: Condition of MS Air Mag Circuit Breakers as of 2022 and 2029 without investment

The switchgears proposed for replacement are functionally obsolete, and replacement parts are no longer available. This makes maintenance of the existing switchgear difficult and expensive, as replacement parts need to be custom made or scavenged from other switchgears. Replacement with new switchgears supported by current manufacturers will allow Toronto Hydro to more efficiently maintain the switchgear as individual components fail in the future.

The switchgears planned for replacement over the 2025-2029 period, shown in Table 10 below, are currently showing signs of deterioration and are anticipated to have circuit breakers with at least in HI4-Material Deterioration by 2029.

Table 10: MS Switchgear Proposed for Replacement

Station	Switchgear	Age at Replacement	Replacement Year
Elmhurst MS	T1SG	63	2025
Midland Lawrence MS	T1SG	61	2025
Hardwick MS	T1SG	65	2026
Windsor MS	T1SG	58	2026
Oberon MS	T1SG	61	2027
Palmwood MS	T1-T2SG	61	2027
Hunting Ridge MS	T1SG	61	2028
Renforth MS	T1SG	63	2028

Station	Switchgear	Age at Replacement	Replacement Year
Walney MS	T1-T2SG	61	2028
Belfield MS	T1-T2SG	65	2029
Braeburn MS	T1SG	61	2029
Centennial Darcy Magee MS	T1SG	58	2029

New switchgears will be arc-resistant and installed with vacuum circuit breakers, a low-maintenance and reliable model of circuit breakers. Each switchgear replacement will also involve the installation of a new SCADA (supervisory control and data acquisition) system at the station since the existing system has far surpassed its useful life and is highly integrated with the switchgear. As a result, MS switchgear renewal will also aid in Toronto Hydro's efforts to renew its fleet of RTUs, as discussed in Section E6.6.3.3 below.

Figure 15 shows the age profile of Toronto Hydro's MS switchgear in 2024 and 2029 under the proposed renewal and conversion plans (see the Area Conversions program, Overhead System Renewal, and Underground System Renewal - Horseshoe, which will remove a switchgear from service).[2]

The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high. The proposed renewal plan will result in no units that exceed 65 years (i.e. the new target maximum age) by 2029. Similarly, with the proposed renewal plan, the number of switchgears aged past useful life in 2029 will be similar to that at the end of 2024, and is broadly expected to maintain MS reliability. Figure 15 shows that the proposed plan results in nearly a flat age profile over ages 50-64 years. This will permit stable and executable pacing for the Segment over the next 20 years.

[2] Exhibit 2B, Section E6.1.

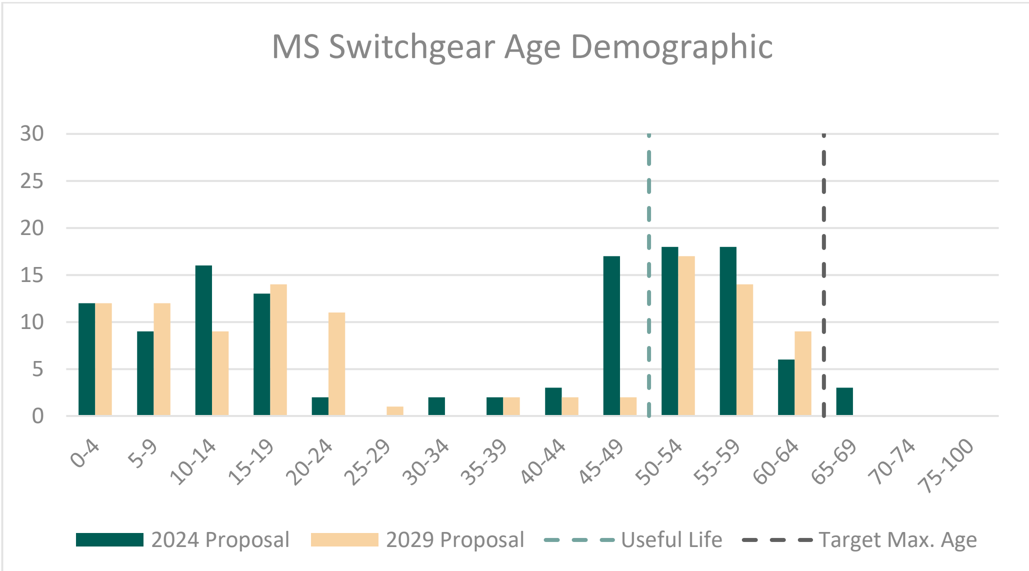


Figure 15: Age Profile of MS Switchgear

2. Power Transformers

The useful life of a power transformer is 45 years. If no investment is made to replace power transformers, there will be an increase in power transformers reaching conditions of material deterioration and end of serviceable life by 2029, as shown in Figure 16 below.

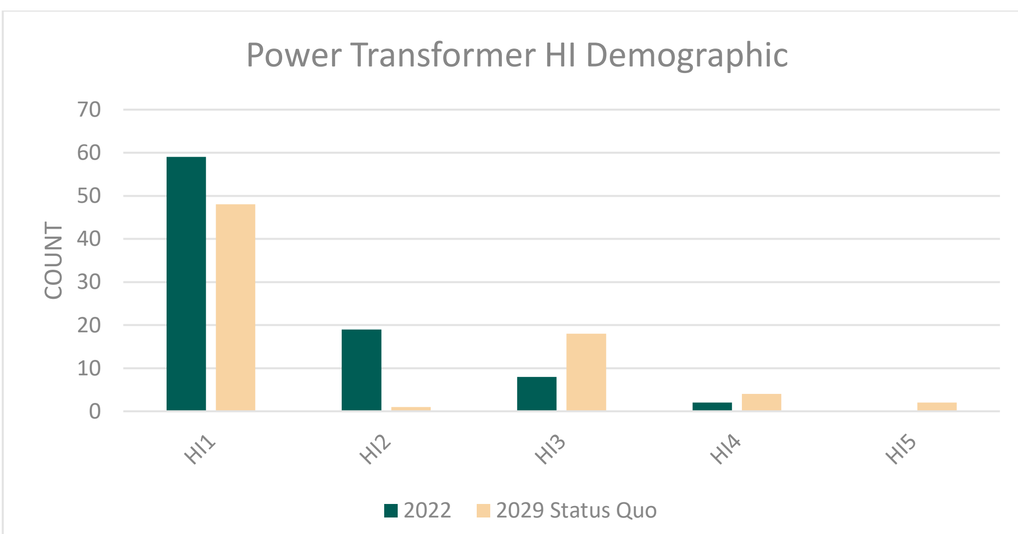


Figure 16: Power Transformer Asset Condition as of 2022 and in 2029 without investment

Over the 2017-2022 period, Toronto Hydro experienced an increased number of power transformer failures, shown in Figure 17. This increase in failures occurred despite decreasing numbers of units past useful life (45 years) as shown in Figure 17 and Figure 18.

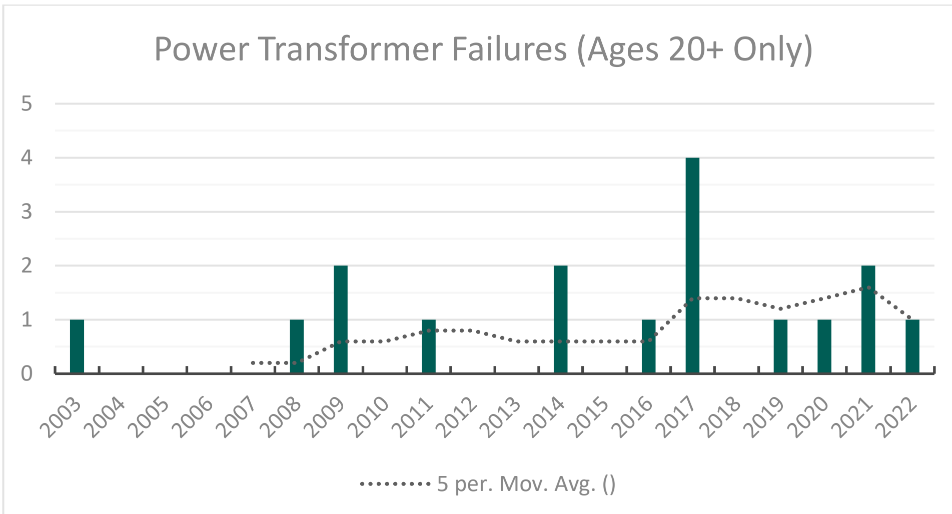


Figure 17: Count of Power Transformer Failures

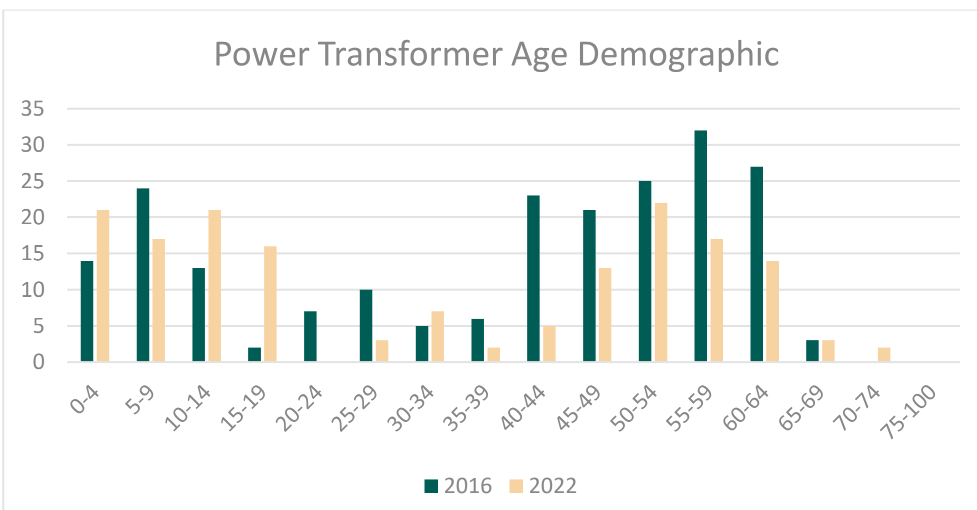


Figure 18 : Power Transformer Population Demographics in 2016 and 2022

To address this emerging trend, Toronto Hydro has taken two actions. First, Toronto Hydro has revised its target maximum age for its power transformers down from 70 to 65 years, in alignment with previous rate applications. The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high, as was observed in the 2020-2024 rate period. If a MS major asset fails, then all connected customers (hundreds to thousands) will experience an outage where restoration would typically occur in half and hour to six hours. The subsequent repair or replacement of the failed asset occurs over a period of weeks or months. By adopting the new target maximum age, the utility intends to avoid reactive replacement. Second, Toronto Hydro is proposing to increase the pace of renewal over 2025-29 compared to 2020-2024, which is discussed in further detail in Section E6.6.4.2.

In addition to customer outages, power transformer failures can have significant safety and environmental impacts on an MS. Upon failure, the tank of the power transformer can rupture, result in oil fire, and even explode. Power transformers hold thousands of litres of oil, which upon failure can result in oil spills and fuel large fires.

All transformers targeted for replacement over 2025-2029, listed in Table 11, will be 54-66 years old at the time of replacement. This level of pacing is required to combat an increased failure rate and ensures the utility is not replacing an increased number of power transformers in the next rate application period. Units will be replaced with units of the same or lesser capacity, where possible, to minimize costs. For example, the failure of power transformers listed in Table 11 that are slightly past their useful life would impact a comparatively large proportion of customers. Planned renewal work is necessary because the reactive replacement of a failed unit takes three to six months to complete even with spare transformers on hand.

Table 11: Power Transformers Proposed for Replacement

Station	ID	Additional Concerns	Replacement Age	Replacement Year
Elmhurst MS	2491	• High power factor • Low insulation resistance	66	2025
Hartsdale MS	2403	• Very high power factor • Low insulation resistance	65	2025
Midland Huntingwood MS	2808	• High power factor & poor power factor sweep • Low insulation resistance	56	2025
Windsor MS	2472	• Questionable power factor • Low insulation resistance	62	2026
Canadine Midland MS	2778	• Low oil dielectric breakdown	60	2026
Palmdale Sheppard MS	2824	• Questionable power factor	53	2026
Oberon MS	2471	• Very high power factor	64	2027

Station	ID	Additional Concerns	Replacement Age	Replacement Year
		• Low insulation resistance		
Palmwood MS	2484	• DGA[3] indications of arcing • Questionable power factor	67	2027
Dunsany MS	2408	• N/A	67	2027
Hunting Ridge MS	2492	• Questionable power factor	64	2028
Sheppard Kennedy MS	2805	• Questionable power factor • Low oil dielectric breakdown • Low paper degree of polymerization	58	2028
Meteor MS	2505	• High power factor	59	2028
Braeburn MS	2442	• High power factor • Low insulation resistance • Poor winding resistances	64	2029
Centennial MS	2412	• N/A	66	2029
Belfield MS	2504	• N/A	60	2029

Figure 19 below shows the age profile of Toronto Hydro's power transformers at the end of 2024 and 2029 under the proposed replacement and conversion plans (see the Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal Programs), which will remove power transformers from service.[4] Toronto Hydro identified 17 power transformers which to be replaced over the 2025-2029 rate period due to their condition, age, and failure impact. Under the proposed replacement plan, noticeable decreases in the number of units past useful life will be maintained by 2029, and the number of units aged beyond the target maximum age of 65 will be nearly equal compared to 2024.

[3] Dissolved gas analysis ("DGA") is a test often used to identify previous and/or persistent thermal and/or electrical faults occurring within a power transformer.
[4] Exhibit 2B, Section E6.1; Exhibit 2B, Section E6.2; Exhibit 2B, Section E6.5

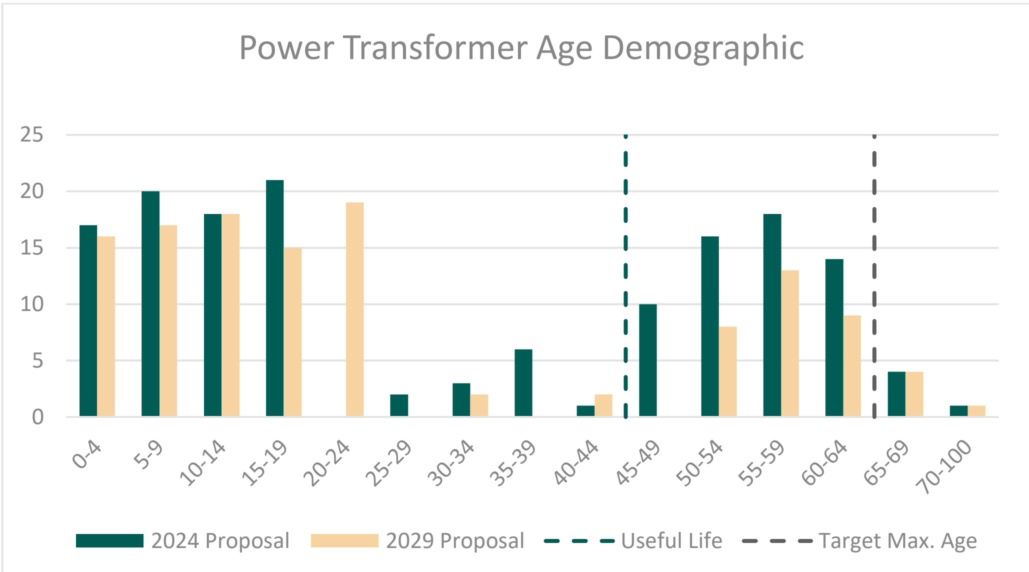


Figure 19: Age Profile of Power Transformers

Although newly installed power transformers contain no PCBs, a release of transformer insulating fluid must still be remediated and potentially reported according to the Environmental Protection Act.[5] To this end, Toronto Hydro will also install an oil containment system as part of its power transformer replacements. Toronto Hydro has been following this practice for all of its power transformer replacements since 2017. The oil containment system will prevent the release of oil into the environment should the power transformer develop an oil leak or tank rupture due to failure. Transformer replacements will also include the replacement of the transformer's primary supply, as Toronto Hydro has been doing for all of its power transformer replacements over 2020-2024.

By replacing the end-of-life power transformers targeted in this segment, Toronto Hydro will mitigate the risk of power transformer failure at its Municipal Stations, thereby maintaining the reliability of its MS.

3. MS Primary Supply

The MS primary supply, or station ingress, consists of all assets in the station between the distribution system and the primary side of the station transformer, including primary cable and a primary disconnect switch (or occasionally circuit breaker). These assets are used to supply the

[5] Environmental Protection Act, R.S.O. 1990, c. E.19. Article 92, 93.

station transformer with power, or to disconnect the transformer from its supply for maintenance or during a fault. It takes three months to reactively replace a failed primary supply.

Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. As part of this segment, Toronto Hydro proposes to continue replacing the primary supply at MS where power transformers were previously replaced, but only where the primary cable is direct buried or in direct buried duct since this comprises the majority of the failure risk.

Over the 2025-2029 rate period, Toronto Hydro proposes to replace the primary supply at one MS as listed in Table 12. The proposed station was selected on the basis of failure risk as determined through the age and configuration of the primary supply assets.

Following this project, the remaining primary supplies in the system will be renewed with their power transformer as part of the scope of a power transformer renewal project, as has been done since 2019. This work will mitigate the risk of a primary supply failure.

Table 12: MS Primary Supplies Proposed for Replacement

Station	Age at Replacement	Replacement Year
Markham Pandora MS	63	2027

The useful life for a primary disconnect switch or a primary circuit breaker is 45 years. For non-lead primary cable, present at the proposed stations, the useful life typically ranges from 25-50 years, depending on the type of cable. All MS primary supplies will be past their useful life at the time of proposed replacement.

The existing primary disconnect switches are obsolete end-of-life assets. They can no longer be replaced like-for-like as they are non-standard and no longer manufactured. Primary disconnect switches will be replaced with a standard padmounted switch commonly used in Toronto Hydro's distribution system.

By replacing the end-of-life and obsolete MS primary supplies, Toronto Hydro will mitigate the failure risk these assets pose at its MS, thereby maintaining MS reliability.

E6.6.3.3 Control and Monitoring

Toronto Hydro uses control and monitoring systems at its TS and MS to protect its equipment, provide operators with system oversight, and allow for remote switching operations. Ultimately this allows Toronto Hydro to reduce outage durations and provide customers with higher reliability. Major Control and Monitoring assets include RTUs and protection relays.

During the 2020-2024 rate period, Toronto Hydro prioritized and is on track to complete the installation of new RTUs at MS that did not have any monitoring systems. Toronto Hydro also prioritized and is on track to complete the Interstation Control Wiring upgrades from copper to fiber (which will result in the removal of that subsegment since it is no longer required). However, there are still copper communications remaining on the system between TS and customers which are planned to be addressed during the 2025-2029 rate period through Relay Renewals.

The 2020-2024 rate period also introduced the Pilot-Wire Protection renewals which has since been expanded to replace other higher risk protection relays such as URD distribution relays and transfer trip relays in the downtown Toronto region.

In addition, Toronto Hydro proposes to modernize its fleet of station relays as part of its Grid Modernization Roadmap.[6] Toronto Hydro will replace its obsolete electromechanical relays with modern digital relays, in order to improve its system observability to the levels needed to achieve an intelligent grid. Toronto Hydro's drivers for its Control and Monitoring assets are summarized in

[6] Exhibit 2B, Section D.5.

Table 13 below.

Table 13: Control and Monitoring

Subsegment	Description	Drivers and Failure Consequences
RTU Renewal	RTU Replacement	The main driver is the failure and risk of aging TS/MS RTUs with secondary driver of functional obsolescence since some RTUs have technology that the suppliers are either no longer in business, replacement parts are no longer available, or minimal support is available to the product from the manufacture. The consequence of an RTU failure is a loss of telemetry data and remote control operation at the station. The loss of remote control operation would increase outage durations for any potential outages that may occur.
Relay Renewal	TS/MS Relay Renewal	The main driver is the modernization of old electromechanical relays to digital relays. The benefit of upgrading the relays to digital is the ability to record events for historical view of issues, as well as better relay diagnostics, enhanced outage fault location, and enhanced protection system security.
	Transfer Trip Relay Renewal	The main driver the risk to replace aging electromechanical Transfer Trip protection systems as well as the copper communication cables used for larger customers. Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. Failure consequence of these systems is an outage to the large customer who rank reliability as their highest priority.
	Pilot-Wire Protection Renewal	The main driver is the risk to replace aging electromechanical pilot-wire protection systems as well as the copper communication cables used for larger downtown customers (including financial institutions, hospitals, telecom companies, sewage plants, etc.). Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. The consequence of these systems failing is an outage to large customer who rank reliability as their highest priority.

Control and Monitoring assets are common to both TS and MS and vary in size and complexity depending on the station and its geographical location. Systems located in downtown Toronto TS are treated with a higher priority than systems located in MS. However, systems in all stations are important because control centre operators rely on them to oversee, control, and protect the system. Modern operation of the electrical grid relies upon having real-time data and control available at the station level at all times.

1. RTU Renewal

As shown in Table 14 below, 29 percent of Toronto Hydro's RTUs are planned to be operating as obsolete RTUs or beyond their useful life of 22 years as of 2024.[7] Many of Toronto Hydro's RTUs are still built from early computer technologies. Computer technology has advanced considerably in the past 25 years making it difficult to find replacement parts that maintain backwards compatibility with what are now obsolete technologies (i.e. MOSCAD, DACSCAN, D20 ME, SEL 3332, SEL 2032).

Table 14 below shows the RTUs in various geographical areas, and the percentage of RTUs that are in-service beyond their useful life (as of the end of 2029 without investment). The number of obsolete RTUs drops to 18 percent due to a combination of planned MS Conversion, MS Switchgear Renewals, and Relay Renewals, all of which either remove the obsolete RTU or replace it.

Table 14: RTU Asset Demographic Plan

Region	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without investment)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investments)
Etobicoke	64	2	0	3%	0%
North York	22	11	3	50%	14%
Scarborough	37	14	12	38%	32%
Toronto	58	26	17	45%	29%
Total	**181**	**53**	**32**	**29%**	**18%**

Most of Toronto Hydro's D20 ME RTUs are younger than 22 years. However, some units have suffered premature failures over recent years. Moreover, modification to these units requires use of legacy computer operating systems which are no longer supported by the original RTU manufacturer. Similar to MOSCAD and DACSCAN RTUs, like-for-like replacement parts for legacy D20 RTUs are no longer available for purchase. To resolve these issues, Toronto Hydro proposes to replace these units with newer, non-legacy models which are currently supported.

Last, most of Toronto Hydro's SEL 2032s (MS) and SEL 3332 (TS) RTUs, similar to the D20 MEs, have been discontinued by the manufacturer. As a result, support is minimal and finding replacement

[7] An RTU has a useful life of 22 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", August 28, 2009.

units is difficult since Toronto Hydro has to use spare parts if available from previously installed equipment at stations which no longer require their RTU from renewal or from decommissioning.

When an RTU fails, Toronto Hydro's control centre operators lose control and visibility of equipment at the station, leaving the system in a vulnerable state. If an RTU failure occurs at a critical station, field crews need to be dispatched to the station immediately to manually monitor equipment status and operate where required. This is necessary to ensure Toronto Hydro can adequately respond to outages and prevent equipment damage by ensuring the station operates within its limits. Combined with the difficulty of the repair work required, this makes a failure event operationally expensive and puts customers at risk of longer outages.

To mitigate RTU failure risk, Toronto Hydro plans to replace 33 RTUs in total (19 at the TS, 14 at the MS). With the exception of RTUs at stations with planned switchgear renewal or MS conversions, this plan will result in replacing all at risk RTUs.

2. Relay Renewal

Relay Renewal is a continuation and expansion of Toronto Hydro's Pilot-wire Protection Renewal work from the 2020-2024 rate application. Relay renewal over the 2025-2029 rate period will focus on four categories: TS Electromechanical to Digital Renewal; MS Electromechanical to Digital Renewal; Transfer Trip Relay with Copper Communications; and Pilot-Wire Relay with Copper Communications. The renewal of Toronto Hydro's relays is mainly driven by modernization, to allow for Toronto Hydro to monitor the system with higher accuracy, allowing fault recording, relay diagnostics, and better discrimination of and coordination with faults over a wider range of operational conditions. These benefits of digital relays will also help support Toronto Hydro's Grid Modernization Roadmap by improving Toronto Hydro's system observability and controllability.

While the renewal of Toronto Hydro's Relays is mainly driven by modernization for the majority of relays; the Pilot-Wire Protection Systems along with the Transfer Trip Relays are driven by failure risk due to their age, obsolete copper communications, and importance to the individual larger customers served by Toronto Hydro that require these assets for their distribution needs.

1 Table 15 below shows the categorization and amount of Relay types.

Table 15: Relay Type, Quantity, and Useful Life

Relay Type	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without Investments)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investment)
TS Relay	1063	419	407	39%	38%
MS Relay	724	371	221	51%	31%
Pilot Wire Relay	71	14	14	20%	20%
Transfer Trip Relay	33	7	7	21%	21%
Total	**1891**	**811**	**649**	**43%**	**34%**

The Transfer Trip Relay and Pilot-Wire Relay Renewals will focus on replacing the Relays along with the aging copper communication wires between the TS Relay to the Customer. This will both modernize the system while also mitigating failure risk of older copper wires. Toronto Hydro's planned switchgear replacements require circuit transfers with this protection system to the new switchgear. An upgrade to newer line protection technology is required since new switchgears cannot be made compatible with the obsolete pilot-wire protection relays.

The relay renewal program overlaps with TS/MS Switchgear Renewal as well as MS Conversions which would remove the need for the asset.

Table 15 above shows a reduction of the total relays obsolete/past useful life in 2024 to 2029 from 43 percent to 34 percent, which is mainly due to MS relays from MS switchgear renewal and MS Conversion plans.

Without a protection relay to isolate a feeder fault, the switchgear's bus differential protection would isolate the entire bus in the event of a fault. Consequently, events that should have been a single element failure, impacting a smaller set of customers, would become an entire TS switchgear outage affecting thousands of customers. In addition, defective electromechanical relays are very difficult to diagnose and most often Toronto Hydro discovers a faulty relay once it causes an issue like not tripping the breaker when it should or nuisance-tripping the breaker. New digital relays can avoid these issues since they have self-diagnostics which are part of the benefits and goals of Toronto Hydro to achieve an intelligent grid.

These improvements to replace electromechanical and copper-based relay protection systems with digital relays and fiber communications have the following benefits:

- Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications), operate its system more efficiently, and provide increased value to customers.
- Upgrading to digital relays will support the Grid Modernization Roadmap which requires both system observability (fault locating and system loading and condition) and system controllability (ability to easily control the grid and to make system "self-healing" in future).
- Better discrimination and coordination with faults over a wider range of operational conditions;
- New relays have self-diagnostics which simplifies troubleshooting and makes failures easier to predict;
- New relays have fault recording which can help diagnostics and more accurately find outage trends on a give feeder, bus, switchgear, etc.
- Less manual maintenance and testing since the new system has online monitoring and self-diagnostics; and
- As part of each project, copper lines are replaced with fiber. Toronto Hydro will have complete control of the fiber optic communication cables and not be reliant on a privately-owned third-party corporation (many copper cables are owned by Bell); therefore, a faster

response time can be provided by Toronto Hydro crews in the case of communication line failure.

Toronto Hydro plans to replace 100 TS and 130 MS Electromechanical Relays with Digital Relays. The plans from

Table 15 above, along with current planned Switchgear Renewal work and MS Conversions would replace a total of 497 Electromechanical Relays out of 700 (TS, MS, Pilot Wire, Transfer Trip combined). This would equate to having 21 percent of the system still with either electromechancial relays or relays past their typical useful life or obsolete by 2029.

Toronto Hydro also plans on renewing 7 Transfer Trip Relays and 14 Pilot-Wire Relays along with the Copper Communication Wires to be Fiber. This renewal plan would conclude upgrading the Transfer Trip Relays and Pilot-Wire Relays to Digital Relays as well as conclude the Copper Renewal plans.

E6.6.3.4 Battery and Ancillary Systems

As shown in Table 16 below, ten percent of Toronto Hydro's Battery and Ancillary Systems will be operating beyond their useful life in 2024. Depending on the asset, replacement is required due to poor condition, end of useful life, obsolescent technology, or a mixture of these factors. The Battery and Ancillary Systems segment proposes replacing these supporting systems as required to maintain station integrity and system reliability for Toronto Hydro customers.

Table 16: Battery and Ancillary Systems Demographics

Asset Type	Total # of Assets	Useful Life	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
Battery	148	10	18	69	14
Charger	148	20	11	20	16
Station Service Transformers	44	45	3	3	0
AC Panels	21	-	5	5	0
Air Compressors[8]	14	15	0	0	0
Total	**361**		**37**	**97**	**30**
Percentage			**10%**	**27%**	**8%**

In addition to the renewal of the assets included in the table above, Toronto Hydro has three TS with flood risk requiring mitigation, as detailed in sub-section 4 below. Furthermore, Toronto Hydro has also identified five stations that require new AC panels to mitigate the failure risk of those panels

[8] No work is planned for in 2025-2029 as no air compressor is beyond useful life. During 2020-2024 one Air Compressor was replaced reactively and the other station was sold to a third party.

with obsolete circuit breakers that have reached the end of their useful life. Sub-section will discuss the AC panel replacements in more detail.

1. Battery and Charger Renewal

A battery and charger system is installed at every TS and MS to provide DC power supply and backup for essential protection, control, and SCADA systems. Due to their critical function, station batteries and chargers must be maintained in reliable condition. These systems must be able to supply power for a minimum of eight hours after the loss of main AC power. As shown in Table 17 below, 11 percent of Toronto Hydro's MS batteries, 19 percent of Toronto Hydro's TS batteries, 9 percent of Toronto Hydro's MS charger systems and 0 percent of TS charger systems will be operating beyond their useful life in 2024.

Table 17: Battery and Charger Systems Demographics

Asset Type	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
MS Battery	11%	43%	11%
TS Battery	19%	62%	0%
MS Charger	9%	16%	13%
TS Charger Systems	0	4%	0%

Previously, Battery & Chargers were grouped together into a single category. However, batteries and chargers have different useful lives and replacement schedules and MS and TS unit costs differ by large margins. Toronto Hydro is now providing a breakdown into sub-parts as shown in Figure 17 above.

Battery and charger system renewal is required to mitigate failure risk. All station batteries have a useful life between 10-12 years (depending on the battery type). Batteries deteriorate to the point of failure as they age and a significant number of them are past or close to the end of their useful life. Charger Systems have a typical life of 20 years and once they exceed their useful lives, they are at risk of failing and jeopardizing the station's DC system.

Without replacement, failures are expected to increase resulting in reduced reliability for Toronto Hydro customers as well as significant equipment damage. When a battery or charger fails, its MS or

TS loses the source of DC power supply. This in turn renders all protection, control, Station RTUs, and other communication systems non-functional. Failure of protection and control systems is a major safety and reliability risk as the station would lose its ability to isolate faults, potentially resulting in a station outage. Otherwise, loss of functionality would affect the Control and Monitoring systems with similar failure impacts to those detailed in Section E6.6.3.3.

Therefore, there is a need to maintain the system reliability by ensuring fewer batteries and charger systems continue to operate beyond their useful life. Figure 20 below highlights the decrease in assets past their useful life by replacing the proposed 55 battery units thus minimizing reliability risks.

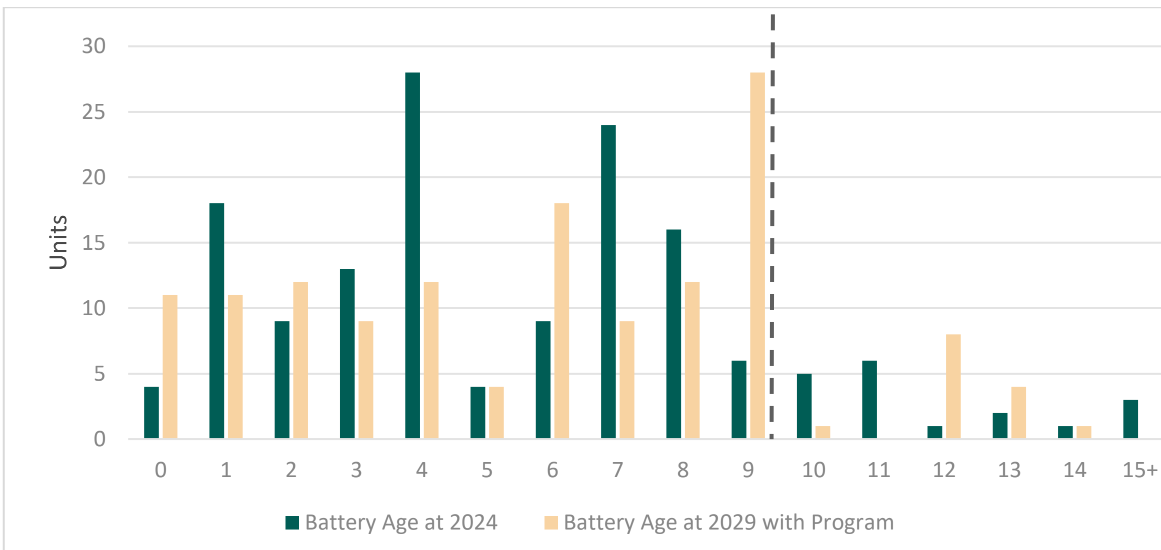


Figure 20: Age Profile of Station Batteries

As listed in Table 18 below, Toronto Hydro plans to replace 55 station batteries over the 2025-2029 rate period, which consist of 16 TS batteries, eight charger systems, and one TS charger. When replacing batteries and chargers, Toronto Hydro will also replace any end-of-life or obsolete DC panels and other smaller series components with similar failure impact.

Table 18: Battery & Charger Proposed Replacement Plan

Year of Replacement	Downtown Replacements	North York Replacements	Scarborough Replacements	Etobicoke Replacements	Total
2025	6	0	5	2	**13**
2026	3	0	4	4	**11**
2027	4	0	3	7	**14**

2028	3	0	5	5	**13**
2029	3	2	4	3	**12**
Total	**19**	**2**	**21**	**21**	**63**

2. Ancillary Renewal

Several ancillary systems require replacement or installation to maintain the integrity of Toronto Hydro's station infrastructure. Toronto Hydro's most pressing risks and needs for these ancillary assets are summarized in Table 19 below.

Table 19: Other Ancillary Systems - Drivers

Asset Group	Asset Class	Drivers and Failure Consequences
Ancillary Systems	*Sump Pumps*	The main driver for this segment is the failure risk of station assets due to flooding. The stations selected for sump pump installation have major equipment installed in the basement (e.g. switchgear, station services etc.) that is at risk in case of water infiltration. Lack of sump pumps can lead to a water build-up which could eventually short-circuit and damage equipment.
	Station Service Transformer (SST)	A station service transformer ("SST") supplies a station with AC power for use in the station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Therefore, an SST failure has a similar impact as a charger failure. Due to this significant failure impact, Toronto Hydro installs two SSTs at its downtown TS. SST replacement projects will only target SSTs supplying these TS. SST renewal is required to mitigate failure risks associated with their age. In addition to the loss of critical systems identified above, a failure of an oil-containing SST has a risk of causing a fire or explosion. Most SSTs are located in close proximity to other critical station assets and pose risk of collateral damage. Therefore, SST replacements will mitigate this safety and environmental risk.
	AC Panels	All the stations loads such as heating, cooling, lighting, ancillary equipment, and DC charging systems are supplied from AC Panels. Unlike SSTs there is no back up for AC panels, therefore, an AC Panel failure has a more severe impact compared to both SST and DC charger failure. The main driver of replacing AC panel is failure risk of obsolete

Asset Group	Asset Class	Drivers and Failure Consequences
		and end-of-life assets. The 5 proposed AC panels are the oldest in the system, which are all more than 50 years old.

AC Panels have the largest failure impact among all battery and ancillary equipment. When an AC panel fails, the SST cannot supply AC power to any of the station loads such as station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Also, no back up AC supply can be brought in. Therefore, the station will have no AC power and only eight hours of DC supply until the AC panel is replaced. During this time, DC supply can be maintained by bringing in a diesel generator and connecting it to the battery charger in order to avoid loss of DC supply for the critical systems. AC panel replacement could take anywhere between a few weeks to few months as the lead times are unknown.

To mitigate the risks identified above, Toronto Hydro plans to replace three sump pumps at the stations identified in the table below.

Table 20: Proposed Sump Pump Replacements

Station	Replacement Year
Glengrove	2025
Wiltshire	2028
Danforth	2029

Toronto Hydro owns 44 SSTs which supply its downtown TS. Three SSTs, equivalent to 7 percent of total SSTs, will be past useful life by 2024, as summarized in Table 21. Other than the three SSTs mentioned, no other SST will reach their useful life during the 2025-2029 rate period. Based on the risk level and relatively low cost of SST replacements, investments will be made to avoid having any of these assets past useful life.

Table 21: Station Service Transformer Demographics

Asset Type	Assets Beyond Useful Life Current State (2024)	Assets Beyond Useful Life Without Program (2029)	Assets with PCB >2ppm
Stations Service Transformers	7%	7%	0

There were originally two SSTs which were assumed to have PCBs (Charles TS, Dufferin TS), both of which have been replaced during 2020-2024 rate period. As shown in Figure 21, all of the targeted SSTs will exceed their typical useful life of 45 years by 2024.[9] Without action during the 2025-2029 rate period, 7 percent of these SSTs will be operating beyond their useful life by 2029.

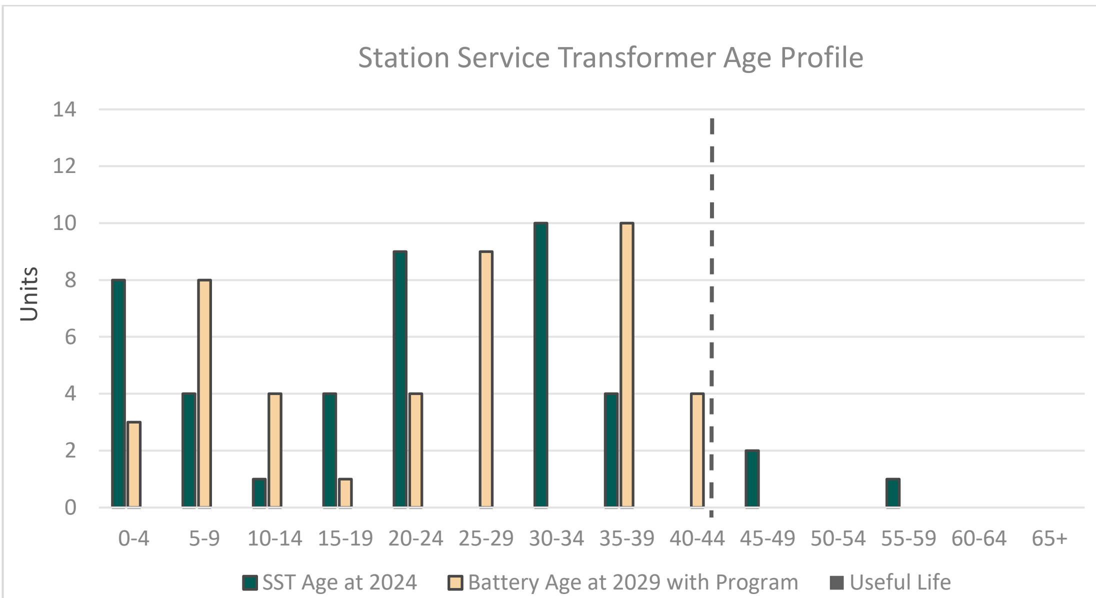


Figure 21 : Age Profile of Station Service Transformers

As listed in Table 22 below, Toronto Hydro plans to replace one SST at each of the three TS during the 2025-2029 rate period. This will significantly mitigate the risk of coincident SST failures at these TS, and in turn will mitigate customer outage risk.

Table 22: Proposed SST Replacements

Station	Asset	Replacement Year
Carlaw	*SST1*	2025
Basin	*SST1*	2026
Charles	*SST2*	2028

Toronto Hydro owns 21 AC Panels in both Downtown and Horseshoe TS. Of these Toronto Hydro plans to replace five AC panels over the 2025-2029 rate period as shown in the table below

[9] An SST has a useful life of 45 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", Aug. 28, 2009.

Table 23 : Proposed AC Panels replacements

Station	Replacement Year
Carlaw	2025
Dufferin	2026
Duplex	2027
Charles	2028
Cecil	2029

E6.6.4 Expenditure Plan

Table 24 provides the Historical (2020-2022), Bridge (2023-2024) and Forecast (2025-2029) expenditures for the Stations Renewal Program. The Program has been organized in 2025-2029 based on the type of system addressed, work required, and driver of the work.

Table 24: Historical & Forecast Program Costs ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Stations TS	12.0	16.7	18.8	18.8	28.8	31.1	31.1	30.0	25.0	16.8
Stations MS	11.5	12.4	2.4	3.9	14.3	10.2	11.3	13.4	17.0	18.4
Stations Control & Monitoring	4.7	3.1	5.1	6.5	8.8	11.9	12.1	13.5	13.1	14.2
Stations Ancillary and Battery	1.9	1.2	1.1	2.2	0.8	3.2	2.2	1.9	3.4	2.9
Total	**30.2**	**33.6**	**27.4**	**31.4**	**52.8**	**56.4**	**56.7**	**58.8**	**58.6**	**52.3**

Spending in the Stations Renewal Program over the 2025-2029 rate period is forecasted to be $282.8 million. This is higher than the $174.7 million forecast in the 2020-2024 Distribution System Plan ("DSP") due to higher than expected project complexity, incremental increases to project scope across multiple projects, and higher than expected inflation costs. However, Toronto Hydro expects to largely complete the projects it had proposed in the 2020-2024 DSP, with the exception of the TS switchgear projects, which have experienced a number of delays.

Complexities involved in the Transformer Stations segment contributing to increased costs include the procurement of unique TS switchgear which meet Toronto Hydro's stringent safety and reliability requirements. As for the Municipal Stations segment, project scope has expanded to include a larger scope of station civil and building refurbishment to support electrical asset renewals, which has also driven unit costs upwards.

For the 2025-2029 rate period, Toronto Hydro proposes to invest $282.8 million, which is a substantial increase compared to the 2020-2024 rate period. This increase is approximately equally split between an increased work volume, and forecasted inflation. Across all segments, an increased work volume is needed relative to the 2020-2024 rate period to maintain station asset demographics. Toronto Hydro utilizes these demographics to set pacing for the 2025-2029 rate period and then, individual projects are then selected based off an overall assessment of risk (See Tables 29, 32, and 35). As discussed in Section E6.6.3, station assets are critical with large failure impacts and have lengthy replacement times. Maintaining station asset demographics is the best strategy to prevent their high failure impact and, in turn, maintain system reliability.

Another substantial increase in work volume is being introduced under the Control and Monitoring segment, where Toronto Hydro's proposes to replace all of its obsolete station electromechanical relays with modern digital relays by 2034.[10] This pacing is proposed to prepare Toronto Hydro's distribution system for modernization, support increasingly sophisticated customer needs, and provide increased customer value through better control and operability.

Work in the Stations Renewal Program is prioritized at three different levels. First, TS work is prioritized above MS work, since TS supply customers of all classes and serve more customers than MS. Therefore, the TS segment as a whole and the portions of the Control and Monitoring and Battery and Ancillary Systems relevant to TS are given the highest priority. Second, the work inside each segment is prioritized differently depending on the specific failure outcomes and risks associated with each asset class. Finally, with respect to each asset class, work is prioritized using a variety of data and considerations including age, condition, obsolescence, customers served, load served, and maintenance effort.

E6.6.4.1 TS Segment Expenditure Plan

As shown in Table 25, Toronto Hydro expects to spend $95.2 million over the 2020-2024 rate period in its Transformer Stations segment. This is $20.7 million higher than the 2020-2024 Distribution System Plan forecast of $74.5 million. Toronto Hydro forecasts that it will complete an additional

[10] Relays which are part of switchgear which have a switchgear replacement planned within 22 years of 2034 are excluded. Otherwise, the newly replaced relays will be replaced again with the switchgear before the useful life of the relays has been reached. The useful life of a digital relay is 22.5 years.

three outdoor breakers and eight outdoor switches in the 2020-2024 rate period than was previously forecasted. The increase is mainly attributed to procurement challenges resulting in increased unit costs. A variance analysis for each subsegment is provided in the following subsections.

Table 25: TS Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TS Switchgear	8.4	15.8	15.6	14.7	27.3	28.9	27.8	27.2	19.8	12.9
TS Outdoor Breakers	1.7	0.8	2.1	1.6	0.7	1.4	1.5	1.5	3.1	1.6
TS Outdoor Switch	1.8	0.1	1.2	2.4	0.8	0.7	1.9	1.3	2.1	2.2
Total	**12.0**	**16.8**	**18.8**	**18.8**	**28.8**	**31.1**	**31.1**	**30.0**	**25.0**	**16.8**

For the 2025-2029 rate period, Toronto Hydro proposes to spend $134 million in the TS segment, completing seven switchgear, 12 outdoor KSO breakers and 63 outdoor switches. As with the 2020-2024 rate application, the majority of the 2025-2029 spending is planned for TS switchgear renewal. The remainder is for the replacement of TS outdoor breakers and TS outdoor switches.

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete two new TS switchgear projects, complete partial work on four new TS switchgear projects, and has completed one carry-over project from the 2015-2019 rate period. The total cost of this work over 2020-2024 is $81.9 million. The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed. Table 26 provides the forecasted spending for each project over the 2020-2024 period.

Table 26: 2020-2024 TS Switchgear – Forecast Costs and Completion Year ($ Millions)

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Strachan A7-8T	1.9	2021	Yes
Carlaw TS A4-5E	12.3	2023	No
Strachan TS A5-6T	18.8	2023	No
Bridgman TS A1-2H	18.8	2025	No
Duplex TS A1-2DX	7.6	2027	No

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Windsor TS A5-6WR	8.0	2027	No
Wiltshire TS A5-6WA	14.4	2026	No
Total	**81.9**		

Since TS switchgear projects span multiple years and rate periods, a discussion of project cost better informs the magnitude of the subsegment spend increase. Table 27 below summarizes the project cost variances and major sources.

Table 27: TS Switchgear for the 2020-2024 Period

Switchgear Unit	Total Project Cost		Project Completion		Major Sources of Variances
	Filed Plan	Current Forecast	2020-24 Filed Plan	Current Forecast	
Carlaw TS A4-5E	11.0	12.3	2022	2023	• Switchgear procurement • Load transfer • Metering
Strachan TS A5-6T	14.3	18.8	2023	2023	• Switchgear procurement • Site preparation (Duct banks)
Bridgman TS A1-2H	14.7	18.8	2024	2025	• Switchgear procurement • DC System Upgrade
Duplex TS A1-2DX	10.2	7.6	2023	2027	• Switchgear procurement • Site preparation (RTU relocation)
Windsor TS A5-6WR	18.4	8.0	2024	2027	• Switchgear procurement • Contingency reinforcement
Wiltshire TS A5-6W	-	14.4	-	2026	• New project addition to the 2020-24 period
Strachan TS A7-8T	-	3.5	-	2021	• 2015-2019 Carry-over project

Over 2020-2023, Toronto Hydro has experienced unexpected challenges selecting and procuring TS switchgears that meets the utility's needs in the space-constrained downtown Toronto. First, the procurement challenges affected all projects throughout 2020-2024, increasing the project cost and delaying the proposed schedule from the previous rate application. Additionally, Toronto Hydro's switchgear supplier discontinued its production of and support for TS switchgear that met the utility's space requirements in 2022. To mitigate supply risks, Toronto Hydro has started to reach out to new manufacturers in efforts to resolve these challenges for the 2025-2029 rate period. The additional time spent on sourcing supplier also caused the schedule delay of switchgear replacement. Preliminary cost estimates show that a 30-50 percent increase for switchgear units is expected.

The two notable projects, Duplex A1-2DX and Windsor A5-6WR, will require additional time for the switchgear procurement, delaying both projects from the previous projected completion date. Toronto Hydro will continue with sourcing suppliers to prevent the future projects from experiencing similar challenges moving forward.

Furthermore, TS switchgear replacement has accrued more costs than prior years due to site conditions. Referencing previous projects, site preparations required additional work to relocate major assets such as more complicated civil work, RTU cabinets and station service transformers in order to facilitate the installation of the new switchgears.

1. TS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-29 period, Toronto Hydro will complete four TS switchgear projects started in the 2020-2024 rate period, complete three new TS switchgear projects, and complete one new building project as advanced site preparations.[11] This presents a minor increase in the number of switchgear replacements under construction over the rate period, relative to the previous rate period. Table 28 below provides the annual spend for each project over the 2025-2029 rate period.

Table 28: 2025-2029 TS Switchgear – Forecast Expenditures ($ Millions)

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Bridgman TS A1-2H	5.6	2025	Yes
Duplex TS A1-2DX	15.5	2027	Yes
Windsor TS A5-6WR	16.2	2027	Yes
Wiltshire TS A5-6WA	6.4	2026	Yes
Danforth MS A1-2DA	16.1	2029	No
Bridgman TS A7-8H	21.9	2029	No
Windsor TS A3-4WR	21.7	2029	No
Bridgman TS A1-2B – Hydro One Building renovation	13.3	2029	No

[11] These building projects are estimated to have lead times of approximately 5 years, and are needed before select TS switchgear projects planned for 2030-2034 can begin.

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Total	**117.0**		

Toronto Hydro has further mitigated risks to achieving its 2025-2029 replacement plan by proposing five TS switchgear replacements over the 2025-2029 rate period. One switchgear replacement is building preparation only. This is the renovation of the Hydro One building for Bridgman due to lack of space for new switchgear installation in the existing TS. The four carry over units are Bridgman A1-2H, Duplex A1-2DX, Windsor A5-6WR and Wiltshire A5-6WA. It is forecasted that $43.6 million will be required to complete the work, which includes the expenditures made in 2020-2024. Three units - Danforth A1-2DA, Bridgman A7-8H, and Windsor A3-4WR - will start work within the 2025-2029 rate period, at a forecast spending of $59.8 million, which is required to complete the projects within the 2025-2029 rate period. One unit that will start its initial site preparations over the 2025-2029 rate period, Bridgman A1-2B, is forecasted to cost $13.3 million and will carry over to the 2030-2034 period. By completing this plan, Toronto Hydro will maintain the number of TS switchgear operating beyond their useful life around the current level, which is approximately 32 percent.

This work plan is attainable (and necessary to manage the aging and deteriorating TS switchgear population) in light of the change in circumstances and preparations made during the 2020-2024 rate period. For example, allocating more resources to coordinate with different switchgear suppliers in 2020-2024 will allow switchgear replacements to proceed smoothly during construction. Other projects, largely being carry-overs, have known execution risks and challenges that have been addressed over the 2025-2029 rate period. To plan for TS switchgear replacements for 2025-2029, a feasibility study of six selected switchgears were performed to provide an outline and summary of the project to budget and schedule, and also mitigate the risk of replacement. Currently, four of the six reports have been completed. The remaining feasibility studies will look into each TS on its own regarding specific issues and forecast issues field staff may experience during execution and provide solutions and projected funding to plan for switchgear renewal projects.

Toronto Hydro believes that accepting the increased risk, specifically the risk of continuing to operate these units beyond their useful life, is prudent and necessary in the context of its overall TS Switchgear replacement needs, priorities, and ability. With continued maintenance and monitoring, Toronto Hydro will mitigate failure risk until the units can be replaced.

Toronto Hydro prioritizes the replacement of its TS switchgear in order of the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 29: TS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Enclosure Construction	Brick constructed switchgear is given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete non-oil air blast circuit breaker 2) Obsolete asbestos-based air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Protection and Control	Switchgear with obsolete protection and control systems are given higher priority.
Arc Flash Rating	Switchgear with lower arc flash protection ratings are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Age and condition assessment are used to gauge the probability of a switchgear failure and when an asset has reached end-of life. Type of circuit breakers, enclosure construction and arc flash rating help determine which of the old standards switchgears that requires renewal. Load and protection and control are used to gauge the impact of the switchgear failure and priority of the replacement.

TS outdoor breakers and switches are located in different stations than TS outdoor breakers and switches, TS switchgear units have longer replacement and lead times and more complex design and construction, and require more capital investment. For these reasons, TS switchgear are prioritized above the other assets in the TS segment, and in the Stations Renewal Program overall.

2. TS Outdoor Breaker – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to spend $6.95 million to replace twelve outdoor KSO breakers at Fairchild TS, Leslie TS, Finch TS, and Bathurst TS. Table 30 below provides an annual breakdown of the forecasted expenditures and the units completed over the 2020-2024.

Table 30: TS Outdoor Breakers - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Units (Breakers)	2	0	3	5	2	12
Expenditures ($M)	1.7	0.84	2.1	1.6	0.68	7.0

The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed.

The 2020-2024 Filed Plan estimated unit cost per breaker replacement at roughly $0.44 million, totalling $4 million for nine units. As a result, the forecasted unit cost over 2020-2024 has increased to $0.6 million above the unit cost for 12 units provided in the 2020-2024 Distribution System Plan of $0.44 million per breaker. The main sources for unit cost increases are: additional work for implementation of Hydro One requirement for demarcation concept, the complex protection scheme for key account customers and material inflation throughout the 2020-2024 rate period.

3. TS Outdoor Breaker – 2025-2029 Expenditure Plan

For the 2025-2029 period, Toronto Hydro proposes to replace 12 KSO breakers, which is the same amount as the previous period. The forecasted cost to complete this work is $9.08 million. Table 31 below provides the annual breakdown of the forecasted expenditures and unit completed over the 2025-2029 rate period.

Table 31: 2025-2029 TS Outdoor Breaker – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	**2026**	**2027**	**2028**	**2029**	**2025-2029**
Units (Breakers)	2	2	2	4	2	12
Expenditures ($M)	1.4	1.5	1.5	3.1	1.6	9.1

As mentioned in Section E6.6.3.1, the oil-based TS outdoor breakers within Toronto Hydro's system are past useful life and will be replaced with vacuum breakers. All of the 12 KSO breakers proposed for replacement contain oil and are operating beyond their useful life, and need to be replaced as detailed in Sub-Section TS Outdoor Breakers of Drivers and Need. By the end of 2029, Toronto Hydro aims to have no outdoor breakers operating beyond their useful life. The pacing of 12 units ensures that no breakers are past their useful life, allowing for increased reliability to be maintained both in short and long term and aligns to Toronto Hydro's standard of non-oil-base circuit breakers.

The average cost for TS outdoor breaker replacement over the 2025-2029 rate period is roughly $0.74 million per unit. This is slightly higher than initial unit pricing estimated for the 2020-2024 period which was $0.60 million per unit. From the four breaker replacements completed from 2020-2022, the actual cost increased to $0.61 million per unit due to material inflation and increased design and construction costs for new Hydro One demarcation panel requirements. Toronto Hydro has adjusted its 2025-2029 estimates accordingly, forecasting that replacement will cost $0.74 million per unit.

Given its 2020-2024 historical achievements in this segment, Toronto Hydro is well positioned to successfully execute its replacement plan for 2025-2029, which proposes at most four replacements in a single year.

Toronto Hydro prioritizes the replacement of its TS outdoor breakers based on the failure risk presented by each breaker. The failure risk is assessed qualitatively by considering the following factors.

Table 32: TS Outdoor Breakers Prioritization

Factor	**Prioritization**
Age	Older breakers are given higher priority
Type of circuit breaker	Priority given in order of: 1) Oil circuit Breaker

Factor	Prioritization
	2) SF_6 Breaker 3) Vacuum Breaker
Condition Assessment	Circuit breakers receiving worse condition assessments are given higher priority
Load	Breakers supplying larger quantities of load are given higher priority
Protection and Control	Breakers with obsolete protection and control systems are given higher priority.
Any other issues raised by station crews (such as broken components)	Given higher priority

The type of circuit breaker, protection, and control are used to gauge the impact of the circuit breaker and the priority. All KSO oil breakers are at their end-of-life and will be targets for replacements this rate application period.

4. TS Outdoor Switches– 2020-2024 Variance Analysis

As shown in Table 33 below, Toronto Hydro forecasts replace 69 TS outdoor switches during the 2020-2024 rate period for a cost total of $6.32 million.

Table 33: TS Outdoor disconnect switches - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switch)	3	6	18	23	19	69
Expenditures ($M)	1.8	0.11	1.2	2.4	0.83	6.3

The 2020-2024 Filed Plan proposed 61 TS switches replacements for a total cost of $1.9 million. With the deferral of Finch TS BY bus renewal, Toronto Hydro plans to allocate the funds to advance the other TS programs as explained in the previous sections. Toronto Hydro forecasts to replace 69 TS outdoor switches during the 2020-2024 rate period at a cost of $6.32 million.

The actual unit cost for the new outdoor switches is much higher than originally estimated in the previous rate application. The average unit cost per switch replacement is roughly $0.09 million, a substantial increase from the estimate of $0.03 million per switch. This Program was a new segment for the 2020-2024 rate application, resulting in higher variance due to lack of experience. The contributing factors for this increase were additional labour costs from the new switches that are gang-operated on ground and steel mount on existing structure, requiring modifications for installation and material cost inflation. Unit cost was $0.12 million from 15 outdoor switches replaced in 2020-2022. As more switch replacement projects occurs, the average of unit cost will be decreased as Toronto Hydro gains more design and installation experience.

5. TS Outdoor Switches– 2025-2029 Expenditure Plan

For the 2025-2029 rate period, Toronto Hydro is proposing to replace 63 TS outdoor switches, a small increase from the original planned units from the previous period. The forecasted cost to complete this work is $8.32 million. Table 34 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 34: 2025-2029 TS Outdoor Switch – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	**2026**	**2027**	**2028**	**2029**	**2025-2029**
Units (Switch)	6	15	10	16	16	63
Expenditures ($M)	0.74	1.9	1.3	2.0	2.2	8.3

By replacing 63 units during the 2025-2029 rate period, Toronto Hydro will reduce the number of TS outdoor switches operating beyond their useful life to 14 percent. As detailed in sub-section 3 of section E6.6.3.1 Transformer Stations, if this work is not undertaken during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be operating beyond or within five years of their 50-year useful life. Performing the proposed work will allow Toronto Hydro to sustainably manage the demographics of its switches over the longer term and reduce the number of switch failures.

The year-by-year pacing for TS outdoor switch replacement has been developed to target the highest priority switches, while maximizing efficiencies in terms of construction and outage coordination. For the years 2025-2029, Toronto Hydro proposes replacements in sets of three switches per year because each selected set can be replaced in a single outage. This reduces unit costs and reliability risk to customers (which would be higher if each switch was replaced as a separate project).

Toronto Hydro forecasts a cost of $8.32 million over the 2025-2029 rate period to complete the 63 switch replacements. This results in an average unit cost of $0.13 million per switch project, an increase from the $0.12 million from the previous 2020-2024 rate period. The contributing factors for this increase are material and labour cost inflation.

Toronto Hydro prioritizes the replacement of its TS outdoor switches based on the failure risk presented by each switch, which is assessed qualitatively and outlined in Table 35.

Table 35: TS Outdoor Switches Prioritization

Factor	Prioritization
Age	Older switches are given higher priority
Switch Type	Priority given in order of: 1) Feeder tie switches 2) Bus disconnect switches 3) Line disconnect switches
Number of repairs	Switches with more repairs are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Due to the nature of switches, multiple switches will be grouped together for replacement in order to minimize the outage time.

E6.6.4.2 Municipal Stations (MS) Expenditure Plan

As shown in Table 36 below, Toronto Hydro plans to spend $44.6 million over the 2020-2024 rate period in its Municipal Stations segment to complete 12 MS switchgear, 12 power transformers, and four MS primary supplies. This presents an increase of $6.9 million compared to the 2020-2024 forecast of $37.7 million. The total number of power transformers is higher than the 2020-2024 Distribution System Plan.[12] The MS switchgear and MS primary supply are less than the proposed volumes in the DSP due to revised project scopes, an increase in the unit cost of MS primary supplies, an increase in civil and stations work, and distribution work (egress and MS primary supply replacement).

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, the projects prior to 2019 did not include the replacement of the MS primary supply as a part of the transformer replacement and thus, no project or design estimates were completed at the time of writing the 2020-2024 rate application. Therefore, the estimates did not fully account for the aforementioned

[12] *Supra* Note 1

factors, such as the stations and distribution portions of work. A variance analysis for each subsegment is provided in the following subsections.

Table 36: MS Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
MS Switchgear[13]	6.4	8.7	0.74	2.7	5.9	5.7	6.2	7.5	11.2	13.2
Power Transformer	3.7	2.6	1.6	0.65	8.1	4.6	5.1	5.3	5.9	5.2
MS Primary Supply	0.39	0.08	0.35	0.55	0.33	-	-	0.56	-	-
Total	11.5	12.5	2.4	3.9	14.3	10.2	11.3	13.3	17.0	18.4

During the 2025-2029 rate period, Toronto Hydro proposes to spend $70.3 million on its MS segment and renew 12 MS switchgear, 15 power transformers, and one MS primary supply. Expenditures are increased due to an increased unit cost (described in variance analysis), a modest increase in volume of work, projects with custom or higher capacity equipment, and forecasted inflation. The majority of the 2025-2029 spending relates to MS switchgear renewal ($43.7 million). The remaining spending is planned almost entirely for power transformers replacement, with only one MS primary supply project proposed for the rate period.

1. MS Switchgear – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete ten new switchgear projects and has completed two carry-over switchgear projects from the 2015-2019 rate period, for a total cost of $25.7 million. Table 37 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

[13] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.

Table 37: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switchgear)	2	5	1	1	3	12
Total Feeders[14]	6	19	3	3	10	41
Expenditures ($M)	7.0	9.5	0.56	2.7	5.9	25.7

The 2020-2024 Filed Plan proposed 12 new switchgear projects for a total cost of $23.4 million, and therefore expenditures are forecasted to increase by $2.3 million. Although the forecasted unit volume is the same, the replaced units have changed slightly. Toronto Hydro has since updated its MS conversion plans by offloading two of the 12 switchgears and is no longer planning for asset renewals at these stations. As a result, Toronto Hydro achieved a sustained risk profile and completed all the proposed work, but at a slightly higher cost than forecasted.

The two carry-over switchgear projects incurred expenditures of $3.2 million over the 2020-2024 rate period and comprised seven feeders. This results in a forecasted net expenditure of $22.5 million for ten new switchgear projects comprising 34 feeders, and an average unit cost of $0.66 million per feeder. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.6 million per feeder. [15]

Major sources for increases in unit cost are due to the practical implications of new arc-resistant switchgear, underestimation of egress replacement costs, and inflation of switchgear material cost.

1) New MS switchgears are arc-resistant. Thus, it usually requires substantial changes to the station building (including a complete rebuild of entire station floor), and additional relocation work of conduits and ancillary equipment.
2) The unit cost for egress replacement projects used in the 2020-2024 rate application was based on only one project that was completed, which did not end up being representative of average cost.

[14] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.
[15] *Supra* Note 1.

3) During the past few years, the material cost of switchgear has significantly increased by 47 percent from 2019 to 2022.

These sources have informed forecasted spending for the 2025-2029 rate period.

2. MS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 12 MS switchgear, which is a modest increase from the previous period. Table 38 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 38: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Units (Switchgear)	2	2	2	3	3	12
Total Feeders[16]	6	7	7	10	11	41
Expenditures ($M)	5.7	6.2	7.5	11.2	13.2	43.7

To complete the proposed 12 MS switchgear replacements, comprising 41 feeders, Toronto Hydro forecasts a cost of $43.7 million over the 2025-2029 rate period. This results in an average unit cost of $1.07 million per feeder which is a substantial cost increase from the previous 2020-2024 rate period. This new unit cost is forecasted using the cost increasing trend for the previous years, which considers these factors: updated unit costs from the 2020-2024 rate period, renewal of custom equipment for four projects, and general forecasted inflation.

For most MS, and for historical projects, the MS supplies an overhead distribution system using standard overhead switches. However, over the 2025-2029 rate period, four projects are planned at MS supplying an underground distribution system, which use custom underground egressing switches. Since these are legacy equipment past useful life, located within the station between the switchgear and the distribution system, and are needed to operate the station, these switches require renewal in parallel with the switchgear.

[16] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.

The additional cost needed to replace the custom underground egressing switches, plus general forecasted inflation, is responsible for the remaining unit cost increase over the 2025-2029 period resulting in an average unit cost of $1.07 million per feeder.

Segment expenditures were forecasted based on project-level estimates for the 12 switchgear replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Project estimates were adjusted based on station configuration as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its MS switchgear based on the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 39: MS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand switchgear failures	MS in areas of low resiliency are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, condition assessment, circuit breaker type, and issues raised by station crews are used to gauge the probability of a switchgear failure and when a switchgear has reached end-of-life. Furthermore, switchgear loading and resiliency of the surrounding distribution system (i.e. ability to withstand switchgear failures) are used to gauge the impact of the switchgear failure and the priority of the replacement.

3. Power Transformer – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to complete 11 new power transformer projects and one carry-over power transformer project from the 2015-2019 period, for a total cost of $ 16.7 million. Table 40 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 period.

Table 40: Power Transformer - Historical Actual and Bridge Unit Volumes and Expenditures[17]

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Power Transformers	1	4	2	0	5	12
Expenditures ($M)	3.7	2.6	1.6	0.65	8.1	16.7

The 2020-2024 Filed Plan proposed ten new power transformer projects for a total cost of $10.3 million, and therefore expenditures are forecasted to be overspent by $6.7 million while unit volume is forecasted to be one unit above target. One unit was advanced from 2025-2029 plans to mitigate outage coordination risks for the 2025-29 rate period, and to begin accelerating the replacement pacing to address an increased failure rate.

The one carry-over transformer project incurred expenditures of $1.3 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $15.4 million for the 11 new power transformer projects, and an average unit cost of $1.40 million. As a result, the forecasted unit cost over 2020-2024 has significantly increased above the unit cost provided in the 2020-2024 Distribution System Plan of $1.0 million.[18]

Major sources for increases in unit cost are due to underestimated civil and facilities modifications, underestimated distribution costs for MS primary supply replacement, and ground grid refurbishment.

[17] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.
[18] *Supra* Note 1.

1) In the 2015-2019 rate application, MS primary supply replacement was not included as part of the transformer replacement. Thus, the substantial amount of cost, including the construction the foundation of large primary switch and construction of new concrete encased duct banks, transformer foundation, and facilities modifications to extend equipment clearances to modern standards, was largely underestimated.
2) Similarly, the distribution portion of the MS primary supply replacement was also underestimated.
3) The station ground grid is an asset vital to employee and public safety. While conducting the civil modifications, the ground grid was often found inadequate and / or degraded, and the deficiencies needed to be addressed.

4. Power Transformer – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 15 power transformers, which is an increase from the previous period. The forecasted cost to complete this work is $26.0 million. Table 41 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 41: Power Transformer - Forecasted Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Power Transformers	3	3	3	3	3	15
Expenditures ($M)	4.6	5.1	5.3	5.9	5.2	26.0

To complete the proposed 15 transformer replacements, Toronto Hydro forecasts a cost of $26.0 million over the 2025-2029 rate period. This results in an average unit cost of $1.73 million, which is a cost increase from the previous 2020-2024 rate period. There are two factors which explain this cost increase: four projects with higher capacity transformers, and general forecasted inflation.

Over the 2020-2024 rate period, only one power transformer renewal project involved the renewal of a unit rated for 10 MVA. However, four such units are proposed for the 2025-2029 rate period. Such units not only have a higher material cost, but they also require a higher rated MS primary supply which also introduces higher material costs. Finally, a unit of this size requires a more sensitive protection scheme to protect it from faults, known as a transformer differential protection scheme.

This protection scheme introduces new equipment and requires a much more intensive engineering design, both of which contribute to a higher cost.

Segment expenditures were forecasted based on project-level estimates for the 15 power transformer replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Lessons learned from variances in the 2020-2024 rate period have been incorporated into project estimates for the 2025-2029 rate period. Project estimates were adjusted based on transformer capacity as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its power transformers based on the failure risk presented by each transformer. The failure risk is assessed qualitatively by considering the following factors.

Table 42: Power Transformer Prioritization

Factor	Prioritization
Age	Older transformers are given higher priority
Dissolved gas-in-oil analysis	Transformers in worse condition are given higher priority
Condition Assessment	Transformers receiving worse condition assessments are given higher priority
Loading	Transformers loaded higher relative to their capacity are given higher priority
Load	Transformers supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand transformer failures	MS in areas of low resiliency are given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, dissolved gas-in-oil analysis, loading, and condition assessment involving electrical tests are used to gauge the probability of a power transformer failure and when an asset has reached end-of-life. Further, transformer loading and resiliency of the surrounding distribution system (i.e. ability to withstand power transformer failures) are used to gauge the impact of the power transformer failure and the priority of the replacement.

5. MS Primary Supply – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete the replacement of four MS primary supplies for a total cost of $1.70 million. Table 43 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 43: MS Primary Supply - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Power Transformers	1	0	1	1	1	4
Expenditures ($M)	0.39	0.08	0.35	0.55	0.33	1.7

The 2020-2024 Filed Plan proposed 11 MS primary supply projects for a total cost of $3.9 million, and therefore expenditures are forecasted to be underspent by $2.2 million while unit volume is forecasted to be seven units below target.

Forecasted unit volume is below target, for three reasons. First, four projects were cancelled because, upon project scoping, the primary cable at these stations was found to be installed in concrete encased duct, which does not meet the criteria set out in Section E6.6.3.2. Second, two projects were cancelled because switchgear replacements were planned for these stations in the 2025-2029 rate period, and to coordinate MS renewal work, the scope of work has been incorporated with their switchgear replacements in 2025-2029. Lastly, one project was deferred to the 2025-2029 rate period to mitigate increased spending in the MS segment as a whole.

Over the 2020-2024 rate period, the average unit cost for the four completed MS primary supply projects is forecasted to be $0.43 million. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.37 million.[19]

Major sources for increases in unit cost are similar to sources for cost increases to power transformer replacements, since the power transformer replacements from 2019 onwards included MS primary supply replacements. In particular, since no projects and no design estimates had been completed at the time of writing the 2020-2024 rate application, both the station and distribution portions of work were underestimated. Based on actual project costs of 2020 and 2022 projects, and estimates

[19] *Supra Note 1*

for 2023 and 2024 projects, the unit cost has been updated to reflect these variances for both station and distribution portions of work.

6. MS Primary Supply – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace one MS primary supply, because this is the last primary supply remaining in the system, which meets the criteria set out Section E6.6.4.2. However, transformer failures which require immediate replacement, without an opportunity to replace the MS primary supply in parallel, may introduce the need for additional MS primary supply replacements.

The cost estimated for the proposed project is $0.56 million. The increased cost relative to the 2020-2024 rate period is due to forecasted inflation.

E6.6.4.3 Control and Monitoring Expenditure Plan

As shown in Table 44 below, Toronto Hydro expects to spend $28.29 million over the 2020-2024 rate period in its Control and Monitoring segment. This presents an overspend of $6.19 million compared to the 2020-2024 Distribution System Plan forecast of $22.1 million.[20] Toronto Hydro forecasts to complete one more TS RTU, 14 more MS RTU, 36 more TS Relays (previously shown as five customer locations, but correlates to two relays per location), and 32km less interstation control wiring as compared to the Filed Plan. A variance analysis for each subsegment is provide in the following subsections.

Table 44: Control and Monitoring Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RTU Renewal	3.8	1.6	4.1	3.6	6.2	2.8	3.1	3.2	3.3	3.4
Relay Renewal[21]	New Subsegment					9.1	9.1	10.3	9.8	10.7
Pilot-wire Protection Renewal	0.36	1.4	1.1	2.6	2.2	Subsegment Absorbed				
Interstation Control Wiring Renewal	0.58	0.15	-0.13	0.27	0.43	Subsegment Completed				
Total	**4.7**	**3.1**	**5.1**	**6.5**	**8.8**	**11.9**	**12.1**	**13.5**	**13.1**	**14.2**

[20] *Ibid.*

[21] Note: Relay Renewal has absorbed the cost and scope of work of "Pilot-wire Protection Renewal" from the 2020-2024 Rate Custom Incentive Risk Application.

During the 2025-2029 rate period, Toronto Hydro proposes to spend $64.70 million in its Control and Monitoring segment to renew 19 TS RTUs, 14 MS RTUs, 121 TS Relays, and 130 MS Relays. Expenditures are increased due to several factors, including an increase in volume of work for relays due to the modernization driver, more work replacing TS RTUs which have higher unit costs than MS RTUs, and forecasted inflation. The majority of the 2025-2029 spend relates to Relay Renewal ($48.91 million). The remaining spend is planned RTU Renewal with most of the costs being for the TS RTU renewals.

For the 2020-2024 rate period, the majority of proposed spending is for RTU renewal at both TS, MS, and installing RTUs at stations without an existing RTU (which is now completed). The remaining forecasted spending is planned pilot-wire protection upgrades and Interstation Control Wiring Renewal. The subsegment for Interstation Control Wiring Renewal is planned to be absorbed with Relay Renewal after the 2020-2024 rate period since they are accompanied by electromechanical relays and supply Toronto Hydro's larger customers. This will also focus on upgrading electromechanical relays to digital relays along with the communication wire upgrades from copper to fiber. This change will allow for more reliable tracking and reporting on work that is completed.

1. RTU Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 12 TS RTU and 48 MS RTU renewals for a total cost of $19.32 million. Table 45 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 45: RTU Replacement - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
TS RTUs	2	2	2	1	5	12
MS RTUs	17	6	11	8	6	48
Expenditure ($M)	3.8	1.6	4.1	3.6	6.2	19.3

The 2020-2024 Filed Plan proposed to complete 11 TS RTU and 34 MS RTU renewals for a total cost of $15.4 million. Expenditures are forecasted to be overspent by $3.92 million while TS and MS RTU units are forecasted to be one unit above and 14 units above respective targets. The total breakdown of RTU type is forecasted to be: 31 MOSCAD, eight D20, ten DACSCAN, one NTU, and ten new RTUs. This results in a total of 33 percent more RTUs renewed while spending 25 percent more. The spending difference can mainly be attributed to doing a larger amount of RTUs at the MS which have a much lower unit cost than at the TS.

a. TS RTU Renewals

The TS System consists of nine different RTUs being SEL 2240, SEL 3530, SEL 3355, D20MX, DACSCAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), ABB COM 500 (obsolete), and SEL 3332 (obsolete).

Toronto Hydro plans to replace a total of 12 TS RTUs during the 2020-2024 rate period for a forecasted total of $7.99 million.

b. MS RTU Renewals

The MS System consists of eight different RTUs being SEL 2240, SEL 3530, D20MX, DACSAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), MOSCAD (obsolete), and SEL 2032 (obsolete).

Toronto Hydro plans to replace or add a total of 48 MS RTUs during the 2020-2024 rate period for a forecasted total of $11.32 million.

2. RTU Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 period, Toronto Hydro plans to complete 19 TS RTU and 14 MS RTU renewals for a total cost of $15.79 million. Table 46 below provides an annual breakdown of the units proposed between 2025 to 2029.

Table 46: RTU Replacement - Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
TS RTUs	4	3	4	4	4	19
MS RTUs	2	3	3	3	3	14
Expenditure ($M)	2.8	3.1	3.2	3.3	3.4	15.8

The RTU Renewal subsegment is mainly prioritized according to the failure risks and outage impacts on customers. However, modernization has been incorporated to include upgrading assets that are obsolete. Stations with a larger number of customers, larger loads, and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 47: Control and Monitoring RTU Renewal Prioritization

Factor	Prioritization
Age	The older the asset, the higher the priority is assigned.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.

a. TS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to increase the rate of RTU renewals at the TS level to keep up with the amount of aging and obsolete RTUs for a total of 19 TS RTUs for a forecasted total of $11.12 million.

The associated costs have been estimated by a combination of historical costs of TS RTU renewals on a per switchgear or bus pair level, as well as considering future expected costs for General Alarm Cabinets. The alarm cabinets will need to be replaced along with some RTU renewals to allow the communication of alarms such as batteries, fire suppression, etc. which would not run to newly replaced RTUs.

b. MS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to reduce the rate of RTU renewals at the MS level for a total of 14 MS RTUs for a forecasted total of $4.66 million.

The associated costs have been estimated by historical costs of MS RTU renewals on a per station level. The original cost estimates for RTUs was broken down based off RTU type, however the distinction between station type seems to be the better factor for estimating unit costs. The overall cost increase is mainly due to assumed inflation.

3. Relay Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to upgrade or renew 46 relays for a total cost of $7.67 million. Table 48 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 48: Relay Renewal - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
TS Relays	2	4	0	19	21	46
MS Relays	NEW SUBSEGMENT					0
Expenditure ($M)	0.36	1.4	1.1	2.6	2.2	7.7

For 2020-2024, Toronto Hydro initially planned to complete ten TS relay renewals (initially number given per customer as five, but assuming two relays per customer its now shown as ten) and 0 MS Relays with a planned spend of $3.5 million. The current plan for 2020-2024 is to complete 46 TS Relays (37 being Pilot Wire/Transfer Trip relays for 18 locations, the rest being URD feeder relay upgrades to digital) and 0 MS RTUs with a planned spend of $7.67 million. This results in a total of 460 percent more relays renewed while spending 119 percent more. This increase in relays with less spend is mainly due to the unit cost of Pilot Wire Renewals seeming to originally include copper renewal costs within the estimate. Also, since this was a newer segment and the costs were more unknown and as such better estimates are being developed as more projects are completed.

4. Relay Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro plans to upgrade or renew 251 relays for a total cost of $48.91 million. Table 49 below provides an annual breakdown of the units completed and proposed between 2025 to 2029.

Table 49: Relay Renewal - Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
TS Relays	18	21	22	17	22	100
Pilot Wire Relay	6	2	3	3	0	14
Transfer Trip Relay	2	1	1	2	1	7
MS Relays	19	23	26	27	35	130
Expenditure ($M)	9.1	9.1	10.3	9.8	10.7	48.9

Toronto Hydro plans to increase the work on relays during the 2025-2029 rate period to modernize the system from obsolete electromechanical relays to digital relays, as well as upgrade remaining Pilot Wire and Transfer Trip Relays to Fiber. In total, 121 TS and 130 MS relays are proposed for an estimated total of $48.91 million.

The Relay Renewal subsegment is mainly prioritized according to the modernization to upgrade electromechanical relays to digital relays. Stations with larger number of customers, larger loads, and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 50: Control and Monitoring Relay Renewal Prioritization

Factor	Prioritization
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.

a. TS Relay Renewals

The TS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. The TS Relays can be broken down into four categories being:

- TS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 100 of these Relays for an estimated $25.33 million.
- TS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these Relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.
- Pilot-Wire Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Pilot-Wire Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Pilot-Wire Protection Systems to the new standards.
  - These upgrades are also required to facilitate a transfer from an older switchgear to a new switchgear renewal, so proactively replacing these units will also help with TS Switchgear Renewals in the future to take a little less time.
  - Toronto Hydro plans to replace a total of five locations with 14 Relays for an estimated $4.77 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.
- Transfer Trip Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Transfer Trip Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Transfer Trip Protection Systems to the new standards.

  - Toronto Hydro plans to replace a total of 6 locations with 7 Relays for an estimated $4.01 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.

The priority of this work will focus on the Pilot-Wire and Transfer Trip Relays since they supply larger customers who prioritize reliability in their supply. These systems are also the most at risk of faults since they still have older copper communication cables versus fiber. The remaining TS Relay upgrades will focus on obsolete electromechanical relay to digital renewals to modernize the system.

The associated costs have been estimated by a combination of historical average costs of other TS Relay renewals on a per cell basis as well as taking the newer and higher estimates for 2023-2024 work.

b. MS Relay Renewals

For the 2025-2029 rate period, the MS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. Similarly to the TS Relays, ideally the plans would include replacing existing digital relays that are more at risk to failure than electromechanical. However, as digital relays are newer to the system, Toronto Hydro does not estimate many will need to be replaced and if existing MS digital relays require renewal, it would take priority over electromechanical relays. The MS Relays can be broken down into two categories:

- MS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 130 of these relays for an estimated $14.80 million.
- MS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.

The associated costs for MS Relay Renewals have been estimated by a high-level estimation taking MS RTU renewal estimates and TS Relay renewal estimates and trying to determine a fair estimate on a per relay basis. Since this is a newer program, the unit costs are still not very well defined.

5. Interstation Control Wiring Renewal – 2020-2024 Variance Analysis

In the 2020-2024 rate period, Toronto Hydro initially planned to do 45km of Copper Wiring Renewals with a planned spend of $3.1 million. The current plan for 2020-2024 as shown in Table 51 below, is to complete 13km of Copper Wiring Renewals with a planned spend of $1.30 million. This results in a total of 71 percent less distance of copper renewals while spending 58 percent less. As a result of the novelty of this segment and considering Toronto Hydro had not previously performed planned replacement of its interstation control wiring, the costs were originally forecasted to be approximately $70k/km. However, based on projects executed during the 2020-2022 period, Toronto Hydro is revising its unit cost to $100k/km. This subsegment is planned to be completed by 2024 since there should be no more copper communications between stations.

Table 51: 2020-2024 Copper Renewal Plans

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
Copper Renewal (km)	3	1	2	6	1	13
Expenditures ($M)	0.58	0.14	-0.13	0.27	0.43	1.3

6. Interstation Control Wiring Renewal – 2025-2029 Expenditure Plan

As shown in Table 52 below, Toronto Hydro expects to complete the requirement of Interstation Control Wiring Renewal from copper to fiber in 2020-2024. While copper communications wires still exist on the system, it should only exist from station to customer which will be addressed in the Relay Renewal program under sub-section E6.6.4.3 above.

Table 52: 2025-2029 Copper Renewal Plans

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
Copper Renewal (km)	Subsegment Completed					
Expenditure ($M)	Subsegment Completed					

E6.6.4.4 Battery and Ancillary System Expenditure Plan

As shown in Table 53 below, Toronto Hydro forecasts to spend $7.3 million during the 2020-2024 rate period in its Battery and Ancillary System segment which is aligned to the 2020-2024 Battery & Ancillary system plan of $7.1 million. This spend is expected to be of $4.55 million and $2.75 million respectively for batteries/chargers and other ancillary projects. Toronto hydro forecasts to complete 37 fewer Battery and Chargers and three fewer Ancillaries (SST, AC Panel, Sump pump, Air compressor). Variance analysis for each subsegment is provided in the following subsections.

Table 53: Battery and Ancillary Systems Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Battery and Charger Renewal	1.0	0.53	0.61	1.9	0.52	0.82	0.71	0.94	0.84	0.80
Other Ancillary Renewal	0.91	0.70	0.49	0.35	0.30	2.4	1.5	0.99	2.6	2.1
Total	**1.9**	**1.2**	**1.1**	**2.2**	**0.8**	**3.2**	**2.2**	**1.9**	**3.4**	**2.9**

During the 2025-2029 rate period, Toronto Hydro proposes to spend $13.6 million in its Battery and Ancillary System segment and complete 63 battery and charger projects, and 11 ancillary projects. The budget of Battery and Charger Renewal has remained relatively similar to the budget approved for the 2020-2024 rate period. However, the cost of the SST and Other Ancillary Renewal have gone up due to two major factors: revised cost of installing Sum Pump and the renewal work required for AC Panels in Downtown TS.

The battery and ancillary systems at Toronto Hydro TS are prioritized above the same assets at MS due to the sheer volume of customers that are served through each TS. A TS asset failure affects significantly more customers than the same asset failing at an MS. Also, recent survey results have shown that the customer needs can be categorized into two main categories which are Rates and

Reliability. The 2025-2029 expenditure plan proposes a plan that looks to minimize the system risk while also maximizing the value of each project.

1. Battery and Charger Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 46 MS and ten TS batteries, 39 MS and two TS charger systems for a total cost $4.55 million. Table 54 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 54: Battery and Charger Renewal - Historical Actual and Bridge and Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Battery units	16	8	10	18	4	56
Charger units	15	8	8	9	1	41
Expenditures($M)	1.0	0.53	0.61	1.9	0.52	4.6

The 2020-2024 Filed Plan proposed 60 MS Batteries, 7 TS batteries, 60 MS chargers, and 7 TS Chargers for a total cost of $4.8 million. Therefore, expenditures are forecasted to be underspent by $0.25 million while unit volume is generally forecasted to be below target. Unit variances are respectively: -14, +3, -21, and -5.

Forecasted unit volume is below target, due the following:

- These include a higher unit cost for the replacement of TS batteries relative to the cost of MS batteries. Therefore, as a result of a higher volume of TS battery replacements, Toronto Hydro replaced fewer MS batteries.
- A number of MS batteries and chargers were replaced reactively during the 2020-2022 period.
- As a part of the work done, Toronto Hydro assessed whether it was necessary to replace batteries and chargers together. However, given the fact that the useful life of chargers is much longer than the batteries, Toronto Hydro decided to only replace the batteries if the charger has not reached its useful life in order to be cost-effective.

In addition, the overspend on stations ancillary renewal caused limitation to the DC battery renewal budget. All the factors explained above contributed to the under attainment for both batteries and charger systems.

2. Battery and Charger Renewal – 2025-2029 Expenditure plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 55 end-of-life batteries and eight charger systems. The forecasted cost to complete this work is $4.12 million. Table 55 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 55 : Battery and Charger Renewal – Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
MS Batteries	8	6	9	8	8	39
TS Batteries	4	3	3	3	3	16
MS Charger Systems	1	2	1	2	1	7
TS Charger Systems	-	-	1	-	-	1
Expenditures($M)	0.82	0.71	0.94	0.84	0.80	4.1

To complete the proposed 55 batteries and eight charger systems, Toronto Hydro forecasts a cost of $4.12 million over the 2025-2029 rate period. This forecast was developed based on project-level estimates for the proposed replacements, and average unit costs of: of $0.041 million per MS battery, $0.12 million per TS battery, $0.06 million per MS charger, and $0.15 million per TS charger. Unit costs were informed by actual and forecasted project costs over the 2020-2024 rate period.

Toronto Hydro prioritizes the replacement of its battery and charger systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 56: Battery and Charger Prioritization

Factor	Prioritization
Age	Older battery and charger systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority (e.g. battery and charger systems located at Transformer Stations are given higher priority than those located at Municipal Stations).
Other factors determined on a case-by-case basis	Systems which are non-standard or contain obsolescent technology are given higher priority (e.g. some DC distribution

Factor	Prioritization
	panels are obsolete). Spare parts that should be accessible routinely are no longer available (e.g. DC panel breaker).
Voltage conversion planned (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets replaced.

3. Ancillary Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete zero air compressors, one sump pump, four SSTs, two carry-over SST, and one carry-over AC panel from the 2015-2019 rate period, for a total cost of $2.75 million. The carry-over projects incurred expenditures of $0.4 million over the 2020-2024 rate period.

Table 57 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 57: Ancillary Renewal - Historical Actual and Bridge Units

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
Air Compressor Replacements	-	-	-	-	-	-
Sump Pump Installations	-	1	-	-	-	1
SST	3	0	1	1	1	6
AC Panels	1	0	0	0	0	1
Expenditures($M)	0.91	0.70	0.49	0.35	0.30	2.8

The 2020-2024 Filed Plan proposed two air compressors, three sump pumps, six SSTs and zero AC panels for a total cost of $2.3 million, and therefore expenditures are forecasted to be aligned while completing fewer units overall. Unit variances are respectively: -2, -2, -2, and +1. Forecasted unit volume is below target, because of multiple factors such as reactive replacements and under estimation of unit costs. However, the major factor of the cost variance is due to the higher unit cost of sump pump installations. Variance analyses for each subsegment are provided in the following subsections.

Air compressors: During the 2020-2024 rate period, the two planned projects were not required as one was replaced reactively and the other was sold to a third party.

Sump Pump Installation: For the 2020-2024 rate period, the plan was to install three sump pumps. Initially, it was determined that no extra civil work is required on site, however after site investigation it was established that there is no existing system in place. As a result, the scope will need to include all the required civil work for the new system installation. This created variance in the project where total budget for sump pumps was $0.2 million and the one project that was completed cost $1.0 million. Toronto Hydro prioritized installing the Cecil TS sump pump since it has many major assets in the basement that would be vulnerable if flooding occurs.

SST: The 2020-2024 Filed Plan proposed six SST renewals for a total cost of $1.9M. One of the SSTs at Dufferin TS was replaced reactively and upon further assessment the SST renewal project at Windsor TS was no longer required. This resulted in two fewer SST replacements.

Overall, Toronto Hydro forecasts to spend $2.0 million on SST replacements. In addition, George & Duke SST renewal was a carryover from the 2015-2019 rate period. This project included replacement of one SSTs and one AC panel. This carryover project incurred expenditure of $0.4 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $1.6M for the four SST renewal projects, and average unit cost of $0.4 million.

As a result, the forecasted unit cost over 2020-2024 has slightly increased from the unit cost provided in the 2020-2024 rate application period. The main factor driving the increase is that Toronto Hydro did not have actual costs or experience executing this work to base its estimates on, as SST renewal was a newer segment in the last rate application period.

4. Ancillary Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to install three sump pumps, and replace three SSTs, and five AC panels. The forecasted cost to complete this work is $9.52 million.

Table 58 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 58: Ancillary Renewal - Historical Actual, Bridge and Forecast Units

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Sump Pump Installations	1	-	-	1	1	3
SST	1	1	0	1	0	3
AC Panels	1	1	1	1	1	5
Expenditure ($M)	2.4	1.5	0.99	2.6	2.1	9.5

Sump Pump Installations: The utility has increasingly focused on storm hardening its system to ensure reliable power supply for its customers. After completing station risk assessments, Toronto Hydro is proposing $3.01 million for the installation of three sump pumps in 2025-2029.

SST: For the 2025-2029 rate period, Toronto Hydro is proposing $1.55M to replace three SSTs located at three of its 15 downtown TS. The slight increase in cost is driven by addition of the metering to the SST cell allowing for better load tracking and renewal foresight in the future.

Currently, Toronto Hydro does not monitor SST loads, and sizing has been based on theoretical values rather than actual loading data to reference. Furthermore, the cost increase is driven by increased unit costs in recent projects attributed mainly to civil requirements and higher labour requirements than originally estimated.

AC Panels: Based on the experience, the average unit cost of AC panel replacement is $0.99 million. Toronto Hydro is proposing $4.96 million for the installation of five AC panels over 2025-2029. It should be noted that the estimated cost is based only one AC panel replacement in the recent years, therefore Toronto Hydro expects cost variances until a number of these projects are completed.

Historically, AC panel replacements have not been completed. It was assumed that when needed, AC panel replacements would be absorbed into the scope of work of SST or charger renewals. However, an SST replacement at George & Duke MS revealed the complexity and true costs of AC panel replacements.

Toronto Hydro prioritizes the replacement of its ancillary systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 59: Ancillary System Prioritization

Factor	Prioritization
Age	Older systems are given higher priority.
Failure Impact on a system-by-system basis	Systems that have more far reaching impacts are given higher priority. For example, AC Panel failure could render entire switchgears breakers inoperable, which could cascade into a larger system problem which has to be solved within the eight hours the DC system could provide, therefore replacing AC Panels will be given a higher priority compared to SSTs. On the other hand, basement flood would have a more immediate impact on the system compared to failure of an air compressor
Number of Customers	The larger the number of customers connected to the station, the higher the priority. For example, ancillary systems located at TS are given higher priority than those located at MS.
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

E6.6.5 Options Analysis

E6.6.5.1 Transformer Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Transformer Stations segment over the 2025-2029 rate period, as presented in this document. This option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. As a result, the Sustainment Option is expected to maintain TS reliability given population demographics and System Health. In addition, two other options were considered: Improvement and Managed Deterioration. The outcome measures, units, and costs of each option are presented in Table 60 below.

Table 60: Transformer Stations Options – Measures, Units, and Costs

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	TS Switchgear	42	32	28	34
	Outdoor Breaker	13	8	8	13

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
	Outdoor Switch	7	14	14	20
System Health (ACA) [%]	TS Switchgear	2	15	13	16
	Outdoor Breaker	5	12	12	19
Arc-Resistant TS Switchgear [%]	TS Switchgear	26	36	40	32
CIR Period		2020-24	2025-29	2025-29	2025-29
TS Switchgear		5	5	7	4
TS Outdoor Breaker		12	12	12	7
TS Outdoor Switches		69	63	63	49
Cost ($M)		95.2	134.1	168.1	112.2

The Improvement Option would replace an extra two TS switchgear with an additional cost of $34.0 million relative to the Sustainment Option. This option would ensure that population demographics meet or exceed those present over the 2020-2024 rate period. This is expected to result in higher system reliability, and would result in an improvement to all measures provided in Table 60. This option is not recommended because customers have indicated almost equal priority on cost and reliability. The Improvement Option favours reliability over cost, and therefore is not aligned with customer priorities.

The Managed Deterioration Option would replace one TS switchgear, five outdoor switchgear breakers and 14 disconnect switches less, resulting in 21.9 million decrease in spending compared to the Sustainment Option. The Managed Deterioration Option would result in more obsolete and old components remaining in the system, thereby marginally decreasing Toronto Hydro's reliability. In order to maintain Toronto Hydro's standards and align with industry standards, this option is not recommended.

E6.6.5.2 Municipal Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Municipal Stations segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance of reliability and cost. As a result, the

Sustainment Option is expected to maintain MS reliability given population demographics and asset failure trends. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 61 below.

Table 61: Municipal Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	40	33	31	35
System Health (ACA) [%]	3	21	20	22
Arc-Resistant MS Switchgear [%]	22	37	40	35
Rate Application Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Switchgear	10	12	15	10
Power Transformers	11	15	17	12
MS Primary Supplies	4	1	1	1
Cost ($M)	44.6	70.3	83.2	57.7

The Managed Deterioration Option would replace two fewer MS switchgear and three fewer power transformers with a cost reduction of $12.6 million relative to the Sustainment Option. The Managed Deterioration Option would result in an increase in the number of the oldest MS switchgear in service, and would maintain population demographics for the power transformers. This is expected to result in lower system reliability, especially given recent failure trends, and would result in a degradation to all measures provided in Table 61. This Option is not recommended because customers have indicated almost equal priority on cost and reliability. The Managed Deterioration Option is expected to reduce reliability, and therefore is not aligned with customer priorities.

The Improvement Option would replace three more MS switchgear and two more power transformers with a cost increase of $12.9 million relative to the Sustainment Option. The Improvement Option would result in equal or improved MS switchgear demographics, and would increase pacing in power transformer replacements to eliminate all units operating past 59 years by the end of 2034. This is expected to result in improved system reliability, and would result in an improvement to all measures provided in Table 61. This Option is not recommended because customers have indicated equal priority on cost and reliability. The Improvement Option is expected to improve reliability at significantly greater cost, and therefore is not aligned with customer priorities.

E6.6.5.3 Control and Monitoring

The Improvement Option is Toronto Hydro's proposed plan for the Control and Monitoring segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: a balance between reliability and cost in terms of RTU Renewal with the addition of modernizing the grid from older obsolete electromechanical relays to digital relays for Relay Renewal. As a result, the Improvement Option is expected to maintain Control and Monitoring reliability given population demographics and asset failure / corrective work trends while also modernizing the grid to new digital relays. In addition, two other options were considered: Sustainment, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 62 below.

Table 62: Control and Monitoring Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Improvement	2029 Alternative 1 – Sustainment	2029 Alternative 2 – Managed Deterioration
RTU APUL/Obsolete [%]	29%	0%	0%	6%
TS Relay APUL/Obsolete [%]	43%	21%	28%	28%
Digital Relays [%]	63%	90%	64%	64%
CIR Period	**2020-2024**	**2025-2029**	**2025-2029**	**2025-2029**
TS RTU	12	19	19	14
MS RTU	48	14	14	8
TS Relay	46	121	98	98
MS Relay	0	130	16	16
Cost ($M)	28.3	64.7	35.7	30.4

The Sustainment Option would focus on replacing both RTUs and digital relays (rather than electromechanical relays) that are obsolete or past their typical useful life, resulting in a cost reduction of $28.96 million. The Sustainment Option would also continue to upgrade pilot wire and transfer trip relay customers with copper communications to fiber and upgrade the relays from electromechanical to digital. This option would replace the same amount of RTUs, pilot wire relays, and transfer trip relays, however, this would still replace 21 electromechanical relays (pilot wire or transfer trip relays) and focus the remainder on the digital relays which are expected to be obsolete or past their typical useful life. For this option, it mainly focuses on the renewal portion of the portfolio rather than modernizing the system. While this option still seems like an improvement due to the continued improvement to the outage measures (other than Digital Relay percentage), the rate of replacement in terms of total RTUs is less than proposed last rate application and relays are now becoming more integrated into the portfolio so it should lower the amount of relays that are considered obsolete or past their typical useful life to a more reasonable percentage. In addition, these percentages also include the help of current planned Switchgear Renewals and MS Conversions. This option is not recommended because with an ever-growing need for modernization, digital relays can help provide a greater ability for control and monitoring Toronto Hydro distribution.

The Managed Deterioration Option is very similar to the Sustainment option, with the difference being to only replace RTUs that are past their typical useful life versus RTUs that are considered obsolete as well. This would result in a reduction from the proposed option of $34.33 million. This option is not recommended, since modernization and having the ability to control and monitor the system has become a high priority and is crucial for many of Toronto Hydro's operations.

E6.6.5.4 Battery and Ancillary Systems

The Sustainment Option is Toronto Hydro's proposed plan for the Battery and Ancillary segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. This option would reduce failure risks and provides positive outcome for customers by maintaining reliability. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and cost of each option are presented in Table 63 below.

Table 63 : Battery and Ancillary Systems – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
Batteries APUL [%]	12%	9%	0%	14%
Charger Systems APUL [%]	7.5%	11%	1%	12%
SST APUL [%]	7%	0%	0%	2%
CIR Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Batteries	46	39	53	32
TS Batteries	10	16	16	16

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
MS Charger Systems	39	7	21	5
TS Charger Systems	2	1	1	1
Sump Pump	1	3	3	1
SST	6	3	3	2
AC Panel	1	5	5	3
Expenditure ($M)	7.3	13.6	15.1	8.8

The improvement Option would replace 14 more MS Batteries and 14 more MS Chargers with a cost increase of $1.42 million relative to the Sustainment Option. Overall, this option is expected to improve system reliability and replace almost all batteries and chargers which are past their useful life by 2029. This option is not recommended, because it does not align as well with customer priorities: an equal balance on reliability and cost.

The Managed Deterioration Option would replace seven fewer MS Batteries and two fewer MS Chargers, two fewer sump pumps, one less SST, and two fewer AC Panels at a cost reduction of $4.89 million relative to the Sustainment Option. This Option would permit an increase in APUL for Batteries and Charger Systems and SSTs. Also, for other ancillary systems, two AC panel renewals and two sump pump installations would be deferred to the next rate application period, which is expected to result in lower system reliability. This Option is not recommended because customers have indicated almost equal priority on cost and reliability.

E6.6.6 Execution Risks & Mitigation

Each segment of the Stations Renewal Program faces challenges which can delay or prevent planned renewal work from occurring. Many of these challenges overlap across the four segments of this Program. These challenges are summarized in the Table 64 below.

Table 64: Execution Risk Applicability by Segment

Segment	Execution Risks						
	Resource Constraints	Planned outages	Asset Failures	Procurement Lead Times	Project Assessment	Distribution Coordination	Other Risks
Transformer Stations	✓	✓	✓	✓	✓	✓	✓
Municipal Stations	✓	✓	✓	✓	✓	✓	✗
Control and Monitoring	✓	✓	✗	✓	✓	✗	✓
Battery and Ancillary Systems	✓	✓	✓	✓	✓	✗	✗

E6.6.6.1 Resource Constraints

All four segments of the Stations Renewal Program use the same pool of stations design and construction resources. Therefore, if there are insufficient resources to complete all the projects planned in the Program, then certain projects will need to be deferred to ensure highest priority projects are completed. Prioritization of projects within this Program is discussed in Section E6.6.3.4. Toronto Hydro is mitigating this risk with the help of third-party providers to complete any projects in excess of Toronto Hydro's resource capacity.

E6.6.6.2 Planned Outages

Most of the renewal work cannot be completed unless a planned outage is arranged. Planned outages are needed to de-energize feeders, power transformers, switchgear, or entire stations without causing power outages to customers, so that Toronto Hydro's crews can safely complete replacement or maintenance work. For Toronto Hydro to de-energize station assets without introducing any undue risk of power outages, Toronto Hydro cannot execute multiple planned outages within the same TS or at two neighbouring MS. Additionally, projects occurring at neighbouring MS are planned to take place in different years, and if possible, at least two years apart.

E6.6.6.3 Asset Failures

Failure of station assets are a source of unplanned station outages which can prevent replacement projects from proceeding due to lack of redundancy. This risk can be mitigated by proactively replacing end-of-life station assets in a timely manner as proposed in this Program.

E6.6.6.4 Procurement Lead Times

Procurement lead times for power transformers, MS switchgear, and TS switchgear range from six to 18 months. For this reason, it is difficult and sometimes infeasible to advance or expedite the replacement of a station asset, even if such a change in schedule would result in a more effective execution of the Program. To help mitigate this risk, Toronto Hydro orders this equipment six to 26 months or earlier in advance of expected in-service dates. In addition, with the planned renewal plan for relays, there is an added risk of procurement issues as there has been issues procuring relays recently. Currently, lead times are expected to be around four to five months but with the addition of so many additional planned digital relays, this may add additional complications with procurement.

E6.6.6.5 Distribution Coordination

Distribution coordination is a challenge commonly affecting the TS and MS segments. All TS switchgear replacement projects and all projects under the MS segment require a distribution project to support the replacement of station assets. A switchgear replacement requires distribution feeders to be removed from the old switchgear and connected to the new switchgear, and replacement of the primary cable within a MS is completed through a distribution project. As a result, if there are delays or resource constraints in the distribution projects, then dependent station projects may also be delayed. Similarly, distribution projects also require planned outages as discussed earlier.

To mitigate the risk relating to distribution coordination, Toronto Hydro engineers strive to clearly define the need for coordination between station and distribution projects at the inception of such projects. On this basis, project managers plan interdependent projects as a single entity so that adequate resources can be allocated and adequate outage planning can be initiated.

E6.6.6.6 Project Assessment

All planned work undergoes a risk assessment by Toronto Hydro's control centre prior to execution. This timeframe is accounted for in the pacing outlined in Section E6.6.3.4.

E6.6.6.7 Other Risks

The risks identified below apply only to their specific segments.

1. Hydro One Coordination (TS)

One of the most significant risks for the successful completion of projects under the TS segment will be Toronto Hydro's ability to effectively coordinate with Hydro One. For example, when replacing a TS switchgear, close coordination is required to transfer Hydro One's supplying transformers from the existing switchgear to the new switchgear. For TS outdoor breaker replacements, all protection and control wiring needs to be verified by Hydro One prior to the breakers being placed back in-service.

With this need for coordination, there is always a risk Hydro One might not be able to secure resources to align with Toronto Hydro's work plan. Additionally, similar to the discussion in Section E6.6.6.2, Hydro One also requires that its own equipment undergo planned outages. Given the need for such planned outages, there is a risk that Toronto Hydro's replacement work will be prevented from proceeding due to a lack of redundancy.

Toronto Hydro mitigates this risk by sharing its high-level replacement plans with Hydro One years in advance of planned project start date. As project execution draws closer, Toronto Hydro and Hydro One exchange detailed information and communicate more frequently to ensure that work plans and resourcing aligns for both companies. For more information, see Exhibit 2B, Section B.

2. Physical Constraints (TS)

Space limitations pose a significant risk to the timely completion of TS switchgear renewal projects under the TS segment. In many cases, Toronto Hydro stations do not have space available to install new switchgear. This is a problem because it is usually necessary to install a new switchgear before decommissioning the existing unit, so as to maintain continuous power supply to customers.

The alternative to this approach is to transfer all customers from the existing switchgear to an adjacent switchgear, decommission the existing switchgear, and then install the replacement in the same space. This can only be done if the adjacent switchgear has enough spare capacity to supply these additional customers. Spare capacity on this order is seldom available.

Toronto Hydro mitigates this risk through use of its Station Expansion Program, which is intended to ensure capacity requirements are met on the distribution system.[22] For example, replacement of the Windsor TS A3-4WR switchgear unit will be possible once Windsor A19-20WR been energized,

[22] Exhibit 2B, Schedule E7.4.

following which the electrical load on the Windsor TS A3-4WR switchgear will be transferred to the new A19-20WR switchgear. A19-20 can only be energized with Hydro One T1/T3 after Hydro One replaces their transformers T5/T6 in Q2 2025. Thereafter, A3-4WR can be decommissioned and its space used to install a new switchgear – A21-22WR. This in turn will allow capacity for the next Windsor TS switchgear unit to be replaced.

In the case of TS building not having enough space to install a new switchgear, a new building or renovation for an existing building is required to facilitate the switchgear replacement. However, this solution requires a long-term plan since the construction of the building may take few years to be ready for switchgear installation. Toronto Hydro plans to request Hydro One to refurbish Hydro One owned building for the new switchgear installation at Bridgman TS.

Due to the lack of space at TS in Downtown, it is impossible to expand the building or is very costly to do so. Small footprint switchgear is necessary for limited space in the TS residing in the Downtown area. Pursing the cost-effective switchgear with narrow feeder cell will be only way to implement switchgear replacement in some TS, like Cecil, Charles, Duplex and Windsor.

By ensuring a reasonable level of spare capacity at or adjacent to heavily loaded stations, Toronto Hydro will be able to effectively plan and execute switchgear replacement while accommodating new customer connections.

3. Customer Coordination (Control and Monitoring)

For pilot-wire system replacements under the Control and Monitoring segment, a challenge to successful execution is customer coordination. Such replacements require customer relays and associated equipment to be replaced in parallel with Toronto Hydro’s equipment. This introduces a risk since projects cannot be scheduled until a time is found which satisfies both the customer’s and Toronto Hydro’s needs. Toronto Hydro minimizes this risk by informing customers several months ahead of planned work, allowing sufficient time for customers to respond and schedule a time that is feasible.

E6.7 Reactive and Corrective Capital

E6.7.1 Overview

Table 1: Reactive and Corrective Capital Program Summary

2020-2024 Cost ($M): 297.6	**2025-2029 Cost ($M):** 328.1[1]
Segments: Reactive Capital; Worst Performing Feeders	
Trigger Driver: Failure	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment and Customer Focus	

The Reactive and Corrective Capital program (the "Program") addresses the replacement of failed and defective major assets, and provides for near-term corrective actions on Toronto Hydro's least reliable feeders. The work required under this Program is unplanned, unpredictable, and non-discretionary. Toronto Hydro carries out the projects and activities in this Program in response to:

- Major asset failures;
- High risk asset deficiencies discovered through planned inspection or in the course of day-to-day work; and
- Feeders exhibiting especially poor reliability.

The Program is grouped into two segments summarized below, and is a continuation of the reactive and corrective activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[2]

- **Reactive Capital:** This segment covers the non-discretionary replacement of failed or failing major assets across the entire system. There are a significant number of asset failures each year. Between 2018 and 2022, on average, there were over 825 Customer Interruptions ("CI") and over 678 Customer Hours Interrupted ("CHI") associated with each major asset failure across the network. Catastrophic failures of assets can require very large investments by Toronto Hydro which, in the absence of a dedicated reactive capital budget, would deprive other programs of necessary resources to maintain the grid. The objective of this segment is to manage unexpected asset failures and address high-risk deficiencies (or assets

[1] Consistent with the 2020-2024 program, the 2025-2029 program forecast includes allowances for streetlight reactive pole replacement, reactive streetlight replacement and streetlight spot improvement.
[2] EB-2018-0165, Exhibit 2B, Section E6.7

approaching imminent failure) in a timely and cost-effective manner. Toronto Hydro's goal is to mitigate the impact of failures on customer outcomes such as reliability, safety, and the environment for 2025 to 2029 and beyond.

- **Worst Performing Feeders:** The Worst Performing Feeder ("WPF") segment focuses on improving overall service reliability for customers supplied from poorly performing feeders. The objective of this segment is to identify feeders performing poorly over a rolling 12-month period and perform work in an effort to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting, the following criteria:
    - Feeders (with no large customers) at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 7 or more, or "FESI-7");
    - Key Account ("KA") feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "FESI-6 Large Customer"); or
    - Feeders (KA or non-KA) that are experiencing systemic issues in a localized area that are resulting in, or are at risk of resulting in, multiple sustained or momentary interruptions.

  Toronto Hydro has also started tracking a new metric called Customers Experiencing Multiple Sustained or Momentary Interruptions of 10 or more ("CEMSMI-10") to put additional focus on large critical customers with Ion meters who are experiencing poor reliability (including power quality) that negatively impacts their operations. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.

  Poorly performing feeders that are designated FESI-7 or FESI-6 Large Customer have a disproportionately negative impact on the system's overall reliability performance, as reflected in metrics such as the annual CI and CHI. In an effort to effectively manage these metrics and the impact on customer, outages are analyzed on poorly performing feeders and targeted work is issued.

As the nature of work in this Program is largely unplanned, unpredictable, and can vary significantly from year to year, Toronto Hydro has based its 2025-2029 forecast costs and projected reactive work volumes for this Program on historical trends and asset condition demographics. The utility forecasts $328.1 million for the Program during the 2025-2029 rate period, which is approximately 10 percent higher than projected for 2020-2024. Timely reactive work improves safety, avoids depriving other capital programs of planned resources, mitigates environmental impacts and public safety risks, and reduces strain on the distribution system.

E6.7.2 Outcomes and Measures

Table 2: Reactive and Corrective Capital Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, FESI-6 Large Customer, System Health Index) by: ○ Promptly replacing major assets that have failed or are at a very high risk of near-term failure; ○ Monitoring feeders that are at a high risk of becoming FESI-7 or FESI-6 Large Customer, and taking near-term mitigating actions where feasible.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives (including compliance with Ontario Regulation 22/04) by: ○ Replacing failed major assets or assets approaching imminent failure to mitigate the risk of catastrophic asset failure causing injuries to utility employees and/or members of the public.
Environment	• Contributes to reducing environmental impact of Toronto Hydro's distribution system by: ○ Reducing the potential for release of harmful chemicals, smoke, or waste (e.g. oil leaks, SF6 gas) into the environment through timely replacement of failing or failed major assets. ○ Improving Toronto Hydro's Spills of Oil containing PCBs measure and reduce the risk of toxic exposure to the environment by eliminating PILC cable and AILC cable containing asbestos and/or lead.

Customer Focus	• Contributes to Toronto Hydro's customer service obligations and objectives by: ○ Ensuring the accurate billing of all smart metered customers based on actual usage by restoring metering service as soon as possible. ○ Supporting compliance with the Electricity and Gas Inspection Act and the Weights and Measures Act.

E6.7.3 Drivers and Need

Table 3: Reactive and Corrective Capital Program Drivers

Trigger Driver	Failure
Secondary Driver(s)	Reliability, Safety, and Environmental Risk

The Reactive and Corrective Capital program is largely driven by the need to address equipment failure. The Program is focused on ensuring asset and system performance at an acceptable standard by:

- Addressing asset deficiencies and failures through like-for-like replacements;
- Completing short-term and small-scale replacements to reduce safety and environmental risks; and
- Executing short term, targeted, and small-scale mitigation measures to reduce the risk of additional outages on feeders exhibiting poor reliability outcomes.

The needs underlying the Reactive Capital segment must be addressed in short order mainly due to asset failure risk. The Worst Performing Feeders segment mainly aims to improve overall service reliability for customers supplied from poorly performing feeders.

Through the Program, Toronto Hydro will be better able to maintain system performance and reliability, manage or eliminate safety risks to the public and Toronto Hydro employees, and ensure customer satisfaction. The trigger and secondary drivers for this Program are discussed below.

E6.7.3.1 Failure Risk

Asset failure on Toronto Hydro's distribution system presents reliability risks which can lead to outages and directly impact customers, environmental risks such as oil spills, and safety risks such as arc flashes, and potentially catastrophic fires. These aspects are discussed in more detail in the following sub-sections. Additionally, timely replacement of failed equipment may be required to avoid operating the distribution system under contingency conditions (i.e. with a lack of feeders or assets that can provide backup supply in the event of a subsequent equipment failure).

Various factors can cause failure, including degradation of an asset's condition, foreign interference, and weather (e.g. major storms). For example: a fractured pole caused by a vehicle accident (i.e. foreign interference); or structural deficiencies of an underground vault as a result of gradual degradation. See Figures 1 and 2 below for reference.

Figure 1: Pole struck by vehicle identified through a patrol

Figure 2: Underground vault structural deficiencies

Age and condition can also affect the health of an asset, and contribute to asset failure. With a higher number of end-of-life assets in the system there is a greater likelihood of failure and need for reactive replacement. Toronto Hydro performs Asset Condition Assessments (“ACA”) on many of its major asset classes. The System Health – Asset Condition for a major asset is ranked from HI1 to HI5 where HI5 indicates the worst condition. Table 4 below shows the percentage of combined HI4 and HI5 populations of major assets divided by their total populations. Wood poles represent the highest number of HI4 and HI5 assets out of the total at risk asset population (e.g. 9,628 in the distribution system) which will continue to drive expenditures in this Program.

Table 4: Proportion of Assets in HI4 & HI5 by Major Asset

Major Assets	2022 Total # of Assets Breakdown		
	Total Assets per Asset Class	Current Health Score 2022 Data	
		HI4 & HI5	% HI4 & HI5
Wood Pole	106,386	9,628	9%
Cable Chamber	10,657	592	6%
Vault Transformer	11,497	258	2%
Submersible Transformer	9,161	180	2%
Padmounted Transformer	7,011	257	3%
Network Vault	470	91	19%
Network Protector	1,728	42	2%
Network Transformer	1,718	43	3%
Total	**148,628**	**11,073**	**7%**

In addition to assessing current condition, Toronto Hydro projects future asset condition for the same assets. As an example, Table 5 summarizes Toronto Hydro’s ACA results for underground submersible transformers, which indicate:

- 180 submersible transformers exhibit material deterioration (HI4 & HI5) and should be considered for replacement as of end of 2022;
- Without any intervention, the number of transformers exhibiting material deterioration is forecasted to more than double by 2029.

Table 5: Asset Condition for Submersible Transformers[3]

Condition	Submersible Transformers	
	2022	**2029**

[3] For more details on Asset Condition Assessment see Exhibit 2B, Section D1 – Asset Management Process Overview.

HI1 - New or Good Condition	8,120	7,330
HI2 – Minor Deterioration	699	642
HI3 – Moderate Deterioration	162	635
HI4 – Material Deterioration	133	240
HI5 – End of Serviceable Life	47	314
Total	**9,161**	**9,161**

Detailed discussions of the condition and age demographics of various asset classes are provided under Toronto Hydro's System Renewal programs.[4]

1. Reliability

An important driver of the Program is system reliability. Depending on the asset and its location within the distribution system (e.g. Main trunk vs. laterals/sub-laterals), the impact may vary from ten customers experiencing an outage to thousands of customers on the main trunk. Asset failures affect the supply of power to Toronto Hydro's customers (e.g. key account customers, residential and/or industrial) and the additional fault current and switching surges create strain on the system that can lead to cascading failures or reduced expected life of other major assets. Historical system reliability impacts are discussed in detail further below.

Figure 3 below shows the causes of sustained interruptions between 2018 and 2022. The chart shows that 41 percent of all sustained interruptions are caused by defective equipment, which is significantly higher than all other causes. The Program focuses mainly on the mitigation of outages caused by major equipment failures; however, it can also mitigate interruptions by various other causes. For example, when replacing a failing overhead transformer, Toronto Hydro may fit the new transformer with an animal guard that may mitigate the "Animal Contact" cause as well as the "Defective Equipment" cause.

[4] Exhibit 2B, Section E6.

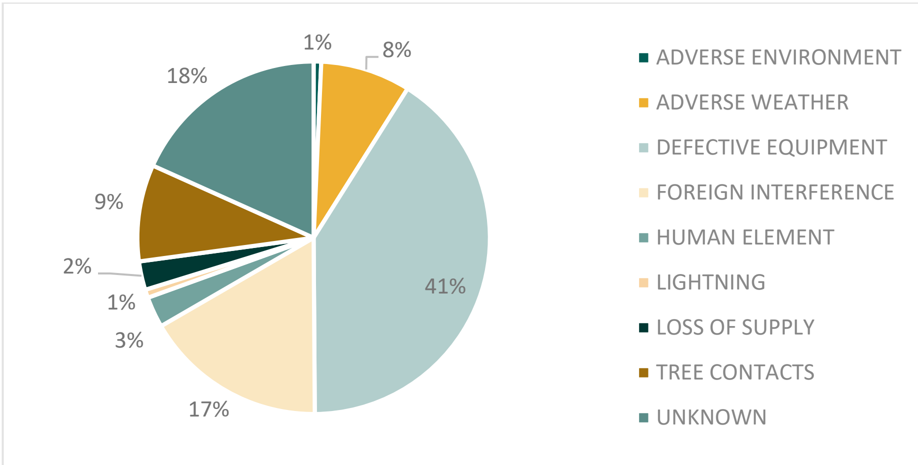


Figure 3: Causes of Sustained Feeder Outages between 2018 and 2022

Table 4 below shows the customer reliability impacts of major asset failures between 2018 and 2022. Each failure of an overhead switch between 2018 and 2022, for example, caused an average of 1,062 customers interruptions and 572 Customer Hours Interrupted. Timely replacement of equipment prior to its failure will mitigate the frequency and duration of interruptions experienced by customers.

Table 4: Average CI and CHI Associated with Failures of Major Assets from 2018 - 2022

Asset	Average Customers Interrupted (CI)	Average Customer Hours Interrupted (CHI)
Overhead Switches	1,062	572
Underground Switchgear	1,204	1,156
Overhead Transformers	115	122
Poles	1,159	673
Underground Cables	881	775
Underground Transformers	596	326

Through Phase 1 of Toronto Hydro's Customer Engagement, "Reliable Service" was identified as a top customer need, and ranked in the top three priorities for all customers, with reliable service being the top priority for key account customers.[5] Most notably, however, there is increasing demand for reliable service from smaller residential customers. A likely contributor to this trend is

[5] See Exhibit 1B, Tab 5, Schedule 1 – Customer Engagement; and Appendix A for Customer Engagement Report.

the transition to work-from-home for many employees at least part of the time, driven by the COVID-19 pandemic. Interruptions to many residential customers is no longer merely an inconvenience, but also impacting businesses through lost labour hours. This Program is intended to address this customer priority, among others, by issuing the necessary mitigation work to reduce the total number of outages and their duration.

2. Safety

Another important driver of the Program is the safety of both the public and Toronto Hydro employees. Failure modes of equipment, depending on their nature, can have immediate and serious safety or environmental consequences. For example, transformers in deteriorated condition may experience transformer fires or oil leaks. Similarly, overhead lines with damaged insulators may lead to tracking and potential pole fires which is a serious safety risk to workers and the public. Furthermore, civil deficiencies such as structural damage in underground assets can jeopardize the public and Toronto Hydro employees. The Reactive Capital segment mitigates safety risks by replacing assets that have failed or are approaching imminent failure. Figure 4 illustrates a pole fire (left) and hazardous civil conditions found in a network vault (right).

Figure 4: Pole fire caused by Tracking (left), Exposed and rusted rebar in Network Vault (right)

3. Environment

Finally, asset failures can also be harmful to the environment. Leaking oil-filled transformers, PILC cable splices, or SF6-insulated switchgear pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely capital replacements help mitigate such environmental risks. The Reactive Capital segment addresses oil deficiencies by replacing leaking transformers. As an added benefit, during transformer replacement, assets that are at risk of containing PCB are also replaced, thereby reducing the possibility of oil spill containing PCBs and contributing to complete removal of all PCB transformers by 2025.

E6.7.3.2 Reactive Capital

The Reactive Capital segment is comprised of work relating to overhead, underground, secondary network, stations and metering assets. The purpose of this reactive work is to restore service to customers and maintain system reliability by addressing severe asset deficiencies and failures. Reactive work occurs on an unplanned basis in response to an asset failure or the detection of a high-risk asset deficiency (e.g. a severely cracked or rotten pole). Such issues cannot be addressed under planned capital renewal procedures and timelines, and therefore must be reactively replaced to maintain the safety and reliability of the distribution system. Reactive work is executed within a short timeframe (e.g. within 15 days to within six months, based on assigned priority level) following the detection of an asset requiring replacement. Reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Asset deficiencies or substandard conditions across Toronto Hydro's distribution system are identified mainly through the Preventative and Predictive Maintenance programs, but can also be identified either during the normal course of operations or through the Emergency Response program, as shown in Figure 5. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs:

- Preventative and Predictive Maintenance;
- Corrective Maintenance; and
- Reactive and Corrective Capital programs.[6]

[6] Exhibit 4, Tab 2, Schedules 1-4 for maintenance programs

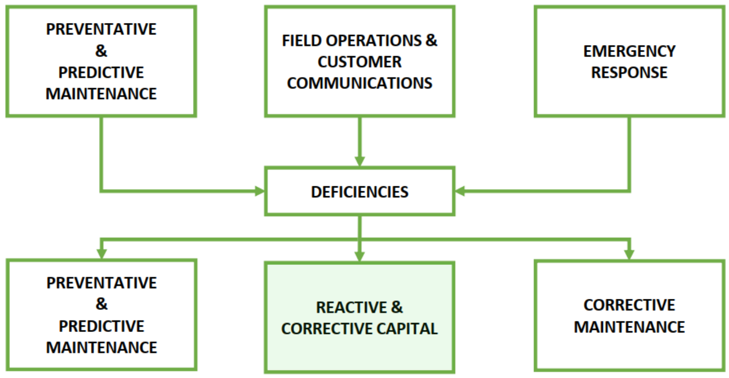


Figure 5: Deficiency Capturing Process[7]

- **Preventative & Predictive Maintenance Activities**: Field crews identify asset failures and deficiencies as part of scheduled maintenance and inspection activities. The inspection cycle depends on the maintenance program as per Reliability Centered Maintenance ("RCM"). The RCM framework is a comprehensive approach to the lifecycle maintenance of distribution system assets. RCM enables Toronto Hydro to leverage a methodological approach to preserve the asset's function by implementing failure management practices that target the potential functional failure.

- **Field Operations & Customer Communications**: Issues or actions identified can also be triggered by sources outside scheduled or planned maintenance activities. These include, but are not limited to:
  - Phone calls from customers to Toronto Hydro;
  - External emails to Toronto Hydro;
  - Observation by field crews during the normal course of operations;
  - Customer inquiries requiring field assessment and follow up; and
  - Line patrol for Worst Performing Feeder Program.

- **Emergency Response:** Reactive capital work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring follow-up remediation and reactive replacements in order to permanently restore power or eliminate safety or environmental risks.

[7] The deficiency capturing process is described in detail in Exhibit 2B Section D3.

Deficiencies from the above sources are reviewed to validate the need for reactive intervention, assessed to determine the nature of reactive intervention required (capital versus maintenance) and the level of urgency and priority (e.g. P1-P4) to be assigned to each asset deficiency. Toronto Hydro addresses the deficiencies identified by issuing work requests.[8]

For the Reactive Capital segment, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories:

- P1 requires resolution within 15 days;
- P2 requires resolution within 60 days; and
- P3 requires resolutions within 180 days;
- P4 which indicates that conditions are to be monitored.

Due to the unpredictable nature of asset failures, the number of reactive work requests may vary from year to year. Catastrophic failures of major assets can require large investments by the utility, and as such, Toronto Hydro requires the Reactive Capital segment to manage imminent major asset failures and address high-risk assets approaching imminent failure. This will help with providing reliable, safe, and environmentally responsible service to customers from 2025 to 2029 and beyond.

Figure 6 below shows the volume of reactive capital work requests issued from 2019 to 2022.[9]

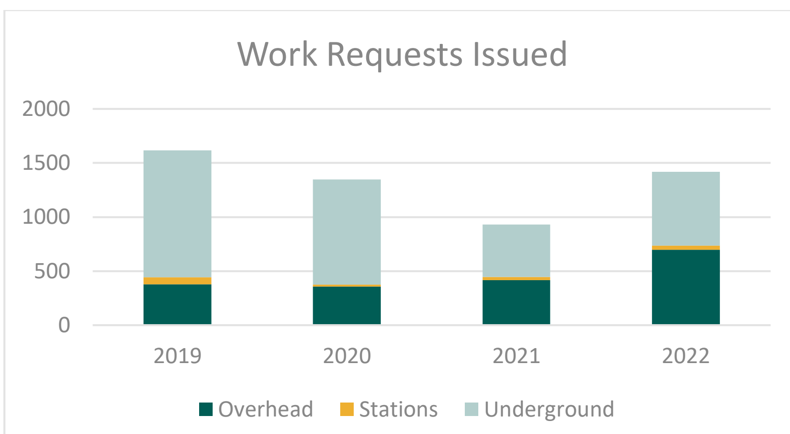


Figure 6: Historical Reactive Capital Work Requests Issued by System Type

[8] Work request are forms issued to assign / schedule corrective work addressed by Toronto Hydro or contractor crews. Deficiencies identified and work requests raised may have a one to one or many to one relationship (i.e. a single work request may contain more than one deficiency).
[9] 2018 data is excluded due to the transition to SAP that occurred during that year.

On average, 1,483 reactive capital work requests were issued each year between 2019-2022, with an overall downward trend, except in 2022, and representing a 9 percent decrease over the 2013-2017 average of 1,624 per year. Generally, the underground system contributes the most to both volume and cost to reactively replace assets, such as Underground Residential Design ("URD") vaults, transformer vaults, and network vaults. Note, that the level of spending depends not just on the volume, but the mix of the different types of work each year. For example, due to the size, operational complexity, and criticality of stations assets, station work can contribute significantly to the overall cost of the Reactive Capital segment, despite the relatively low volume of requests.

1. Metering Assets

The Reactive Capital segment also funds reactive meter replacement. Reactive meter replacement capital work consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters, and primary meters (Including instrument transformers). The loss of communication with a meter is the primary cause of meter replacements. Primary metering units can also fail due to blown instrument transformer fuses which causes customer consumption to be incorrectly read, resulting in incorrect billing. Failed metering equipment not replaced in a timely manner can result in delayed billing and the need to estimate customer consumption.

Table 7 summarizes the estimated number of meter replacement units and costs for the 2025-2029 rate period. The estimated costs were derived based on a four-year weighted average of historical costs. The average percentage of meters failing remains the same but the population is increasing yearly. The meter replacement costs are embedded into the Reactive Capital segment 2025-2029 forecasts in the Expenditure Plan section.

Table 7: Reactive Meter Replacement Costs (2025 - 2029)

	Projected					
	2025	**2026**	**2027**	**2028**	**2029**	**Total**
Meter Replacements (Units)	5500	5600	5700	5800	5900	28500
Meter Replacement Costs ($ Millions)	3.56	3.66	3.76	3.89	4.02	18.88

E6.7.3.3 Worst Performing Feeders

Toronto Hydro's distribution system contains over 1,500 feeders that supply power to over 790,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment breakdown, foreign interference and environmental effects that can cause unplanned outages, specific feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained or momentary interruptions to the customers connected to them. Figure 7 below shows that between 15 and 20 percent of the total CI, and approximately 10 percent of CHI in a given year, are attributed to FESI-7 feeders, which make up less than 2 percent of all feeders, as shown in Table 8 below.

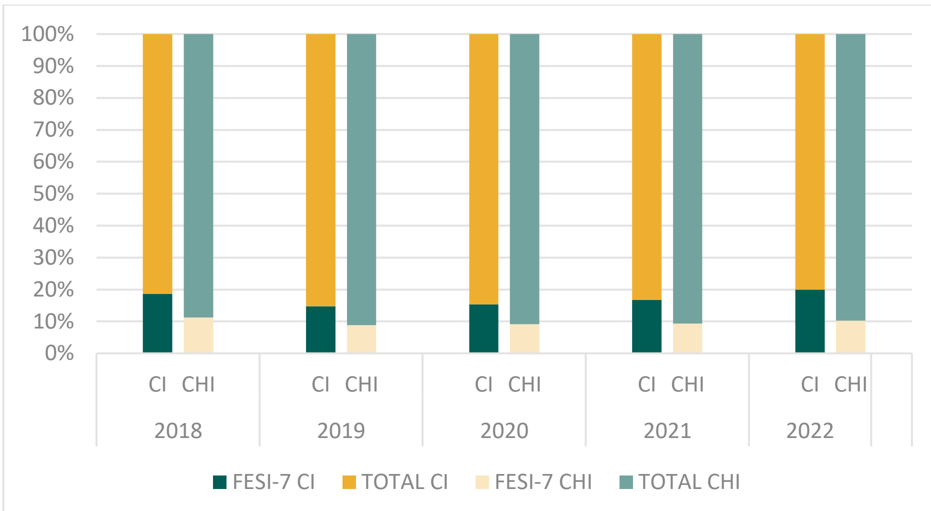


Figure 7: Contribution of FESI-7 feeders to CI and CHI between 2018 and 2022

Table 8: Number of FESI-7 feeders compared to total number of feeders

	2018	2019	2020	2021	2022
# FESI-7 feeders	17	7	9	10	27
Total # feeders	1521				
% FESI-7/total	1.12%	0.46%	0.59%	0.66%	1.78%

Figures 8 and 9 below show the locations of FESI-6 Large Customer feeders in 2020 and 2022 respectively. These feeders typically vary from year to year and are difficult to predict. Since planned renewal programs take a substantial amount of time to plan, design and execute, it is necessary to address emerging issues contributing to interruptions on these feeders in a timely manner.

Figure 8: Locations of 2020 FESI-6 Large Customer Feeders

Figure 9: Locations of 2022 FESI-6 Large Customer Feeders

The main objective of Toronto Hydro's WPF segment is to improve overall service reliability for customers supplied from poorly performing feeders, which aligns with results of the Phase 1 Customer Engagement, where reliability is one of the top three priorities across all types of customer types. This improvement is accomplished by employing a feeder-level analytical approach that selects feeders experiencing a high number of outages or trending towards increased outages, analyzing previous outages to determine the cause, and issuing work intended to address the cause in an effort to mitigate any subsequent outages. The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment may still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Most of this work is targeted for completion within a 12-month period to mitigate the risk of customers being exposed to poor reliability for prolonged periods.

In addition to FESI-7 and FESI-6 Large Customer metrics, Toronto Hydro has begun to track a new metric, Customers Experiencing Multiple Sustained and Momentary Interruptions, or CEMSMI-10. This particular metric closely assesses the experience of each key account customer, as customers may be transferred to alternate supply feeders during contingency scenarios and may not consistently be supplied by their normal supply arrangement throughout the year. Additionally, since many key account customers are also negatively impacted by momentary interruptions (i.e. factory lines, hospital equipment), momentary interruptions are tracked along with sustained interruptions. Where a specific key account customer is trending towards a poor experience over a 12-month period, each feeder that supplies the specific customer will be targeted for analysis in an effort to address any deficiencies that may cause further interruptions.

Through this segment, Toronto Hydro first identifies feeders which are at risk of becoming designated FESI-7 or FESI-6 Large Customer feeders, feeders with KA customers experiencing a high volume of momentary interruptions or power quality issues (i.e. CEMSMI-10), or feeders with specific systemic issues that need to be addressed in the short term. This assessment excludes planned outages, outages occurring on Major Event Days ("MEDs"), outages caused by loss of supply, and interruptions on the secondary side of the distribution transformer. Toronto Hydro then assesses each of the past outages that occurred on the designated feeder, which includes but is not limited to:

- Reviewing comments from the Control Authority and crews attending to the outage;
- Checking for flags raised by SCADA-connected devices; and
- Reviewing voltage and current profiles collected by Ion meters in an effort to localize the outage, so that the cause may be identified and subsequently addressed.

Following a feeder reliability analysis, field crews patrol and inspect the feeders, with a particular emphasis on any locations identified during the analysis, to assess the condition of equipment and identify quick targeted actions that yield immediate reliability improvements. Examples of deficiencies discovered during such feeder patrols are shown in **Error! Reference source not found.**Figure 10 below.

Figure 10: Animal Contact on Metal Switch Bracket (Left)/Rusted Overhead Transformers at Risk of Leaking Oil (Right)

As previously stated and shown in Figure 1, 41 percent of all sustained interruptions are a result of the failure of defective equipment. Through the reliability analysis on poorly performing feeders, assets that are identified as having a risk of imminent failure are targeted for replacement before they would be scheduled for replacement under planned renewal programs. This addresses equipment deficiencies quickly before they cause subsequent outages on already poorly performing feeders.

Between 2020 and 2022, Toronto Hydro issued 107 WPF mitigation scopes to address asset deficiencies across an average of 31 different FESI-7 or FESI-6 Large Customer feeders per year. Figure 11 below shows the breakdown of asset types that were targeted for replacement. Toronto Hydro expects that this trend will continue through the 2025-2029 rate period and that there will be a similar breakdown of asset types requiring replacement through the WPF segment.

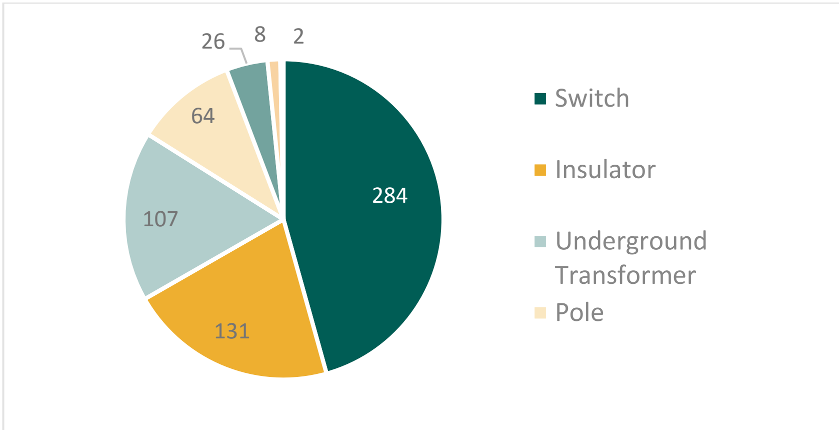


Figure 11: Breakdown of assets replaced under the WPF segment between 2020-2022

The top asset types scheduled for replacement through the WPF segment were overhead switches, insulators, and underground transformers. These assets were targeted for replacement in order to mitigate risk of failures due to the following issues:

Overhead switches with vintage porcelain insulators mounted onto metal brackets are susceptible to electrical tracking, whereby small amounts of current flow from the live switch terminals/end fittings, across the surface of the porcelain shell, to the grounded metal bracket. Electrical tracking is exacerbated by salt spray in the winter months and condensation when warm moisture-laden air comes into contact with a cold porcelain shell. Tracking can cause outages by triggering the operation of upstream protection, as well as degradation of the porcelain shell, leading to its fracture and a full asset failure. Figure 12 below shows a porcelain insulator with a hairline crack and scorch marks. New switches are fitted with larger polymer insulators and are less susceptible to electrical and mechanical failure mechanisms.

Figure 12: Porcelain insulator with small cracks in the shell and scorch marks

- Porcelain insulators mounted onto metal brackets have the same failure mode and mechanism as the above example. New insulators are manufactured using polymer.
- Single-phase submersible transformers manufactured with mild steel tanks and bare, uninsulated low voltage terminals are prone to premature failure where installed in locations susceptible to flooding. Transformers installed in these areas may experience accelerated corrosion of the tank, typically near the base, and potentially heavy corrosion of the aluminum secondary cables and steel tank near the low voltage terminals where the terminals are left bare and water levels inside the vault rise to the height of the terminals. Refer to the photos in Figure 13 below showing two transformers that had been removed from service due to extreme levels of corrosion. New single-phase submersible transformer tanks and lids are manufactured using stainless steel and are fitted with additional components that effectively seal live components from water ingress, mitigating the corrosion.

Figure 13: Mild steel single-phase submersible transformers with heavy corrosion

Figure 14 below shows the historical count of FESI-7 and FESI-6 Large Customer feeders per year. As shown, the annual number of FESI-7 and FESI-6 Large Customer feeders are a small subset of the more than 1,500 total feeders that make-up Toronto Hydro's distribution system and are gradually trending down over time since the inception of the WPF segment. There was, however, a noticeable increase in the number of FESI-7 and FESI-6 Large Customer feeders in 2022 due to the increased sensitivity of the Outage Management System in recording interruptions, which is further explained in Exhibit 1B, Tab 02, Section 4 "Reliability Performance". It is also important to note, that the WPF segment is not the sole driver for the FESI-7 and FESI-6 Large Customer metrics, and that the success of these metrics is also heavily dependent on planned renewal programs, such as Underground System Renewal – Horseshoe.[10]

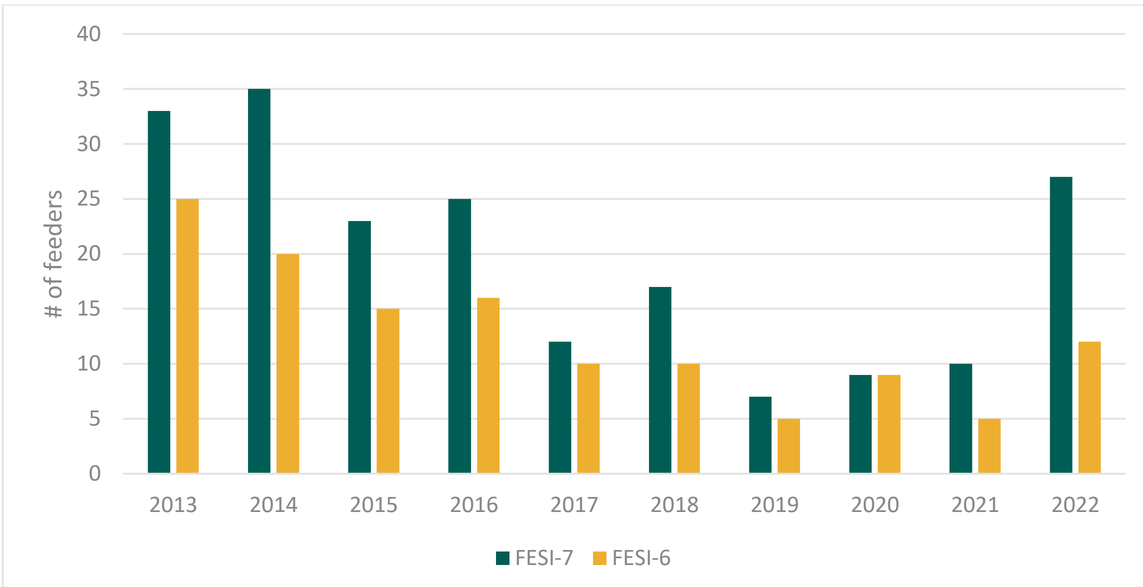


Figure 14: Historical Worst Performing Feeder Interruptions between 2013 and 2022

Although there has been an overall decline in the number of FESI-7 and FESI-6 Large Customer feeders, it is particularly important that the WPF program be maintained to sustain this decrease and continue to mitigate the risk of interruptions caused by equipment failures, as planned renewal programs have been prioritizing the replacement of transformers containing PCBs, which has reduced investment in more reliability-focused work (e.g. replacing high-risk direct-buried cable).

The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power

[10] Exhibit 2B, Section E6.2.

interruptions for customers on feeders that are experiencing especially poor reliability performance, as shown in Figure 14 above.

E6.7.4 Expenditure Plan

Table 9 provides the Actual (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Reactive and Corrective Capital program.

Table 9: Historical and Forecast Program Costs ($ Millions)

	Actual			Budget		Plan				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Reactive Capital	58.7	50.9	56.0	55.1	53.1	55.4	58.4	58.3	60.6	62.8
Worst Performing Feeder	4.2	3.7	3.8	6.7	5.7	6.1	6.3	6.5	6.7	6.9
Total	**62.9**	**54.5**	**59.7**	**61.7**	**58.7**	**61.6**	**64.8**	**64.8**	**67.3**	**69.7**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $165.6 million in reactive capital work over 2020-2022 and projects to invest a total of $273.7 million by the end of 2024 (including forecasted inflation), which is approximately $17 million more than the $256.8 million budget approved by the OEB in the 2020-2024 rate application. Due to the demand-driven, non-discretionary nature of this segment and the volume and mix of work that needed to be addressed, Toronto Hydro could not reasonably constrain spending for this spending to the OEB approved amount.

Actual work volumes and costs will vary from year to year and Toronto Hydro forecasts future costs based on historical trends. Toronto Hydro developed its forecasts for 2020-2024 in 2018 based on the best available information at the time, which reflected an increasing trend that has since plateaued. That being said, Toronto Hydro has since developed a more detailed projection model for its 2025-2029 forecast, which is discussed below.

The predominant driver for the variance during the 2020-2024 rate period is the demand-driven nature of the actual volumes and type of assets requiring non-discretionary replacement. The unpredictable nature of asset failures can vary in type and number of equipment from year to year due to foreign interference or weather. For example:

- The volume of condemned pole reactive replacements can increase as the overall condition of poles deteriorates, as indicated by the number HI4/HI5 poles. Toronto Hydro replaces condemned poles, identified through inspections, both reactively and through proactive (planned) renewal. The total number of condemned poles approximately doubled from 2020 to 2021 and remained at a similar level in 2022. Toronto Hydro has seen a steady increase in reactive pole replacement, which includes not only condemned poles but any pole replacements required due to emergency or storm events. Given the current and projected condition of Toronto Hydro's wood poles, the utility expects this trend to continue.
- The total volume of overhead and underground transformer replacements declined from 2020 to 2022. In 2020, there were 849 transformer related work requests which decreased by approximately 50 percent in 2022. This reduction is likely due to the Toronto Hydro's recent focus on eliminating transformers at risk of containing PCBs, which are also at higher risk of failure due to their age. Toronto Hydro expects the number of transformer replacements to plateau over the next 3 to 4 years.

Toronto Hydro's 2025-2029 Reactive Capital predictive model uses a layered approach, which is based on the previously established weighted moving average methodology, but also incorporates relevant condition-based information for underground distribution transformers to forecast future capital expenditure. The underground transformer forecast leverages historical reactive replacement data to determine the average probability of reactive replacement for a given health index band. The model considers a 3-year window of anticipated asset deterioration as per ACA projections, which corresponds to the longest underground transformer inspection cycle. Expenditures beyond the 3-year window are calculated using the conventional weighted average methodology. Toronto Hydro's corresponding forecast of work request volumes is shown in Figure 15, along with historical actuals.

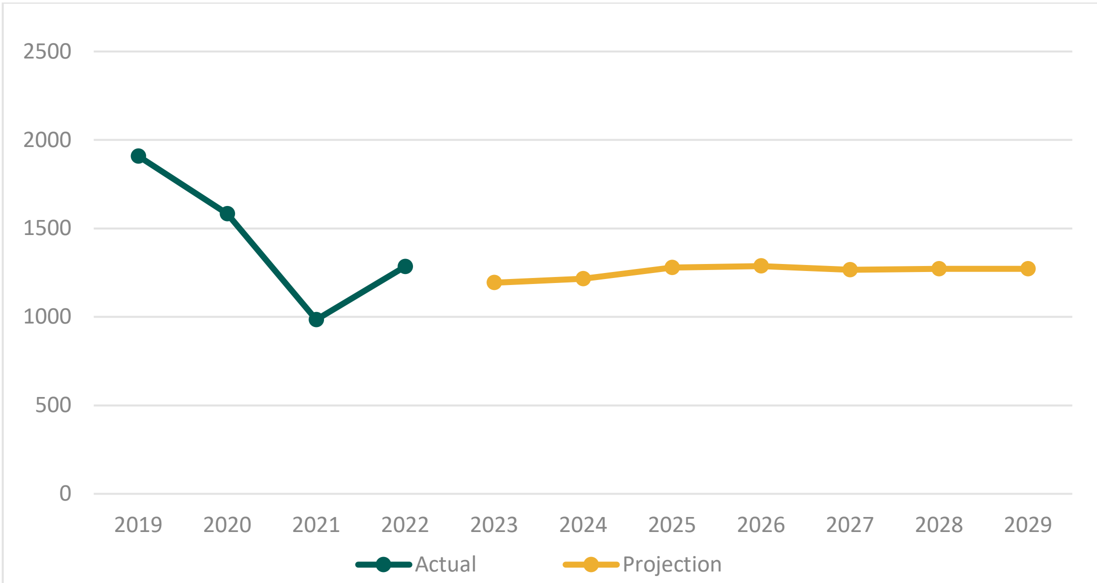


Figure 15: 2019-2029 Reactive Capital Work Requests Actuals and Forecast

As previously noted, the nature of work in this segment is unplanned, unpredictable, non-discretionary, and can vary significantly from year to year. When an asset exhibiting severe deficiencies is found through maintenance inspections, reported by operations teams or customers, or caused by emergency events, the utility immediately assigns personnel to triage and resolve the issue. Based on the expertise and experience of Toronto Hydro engineers and operation teams, deficiencies are evaluated and prioritized for resolution. Crews are then dispatched to address those assets with the highest priority based on severity of the issue and the impact on environmental, safety and reliability.

Since 2015 Toronto Hydro has also undertaken efforts to maximize the productivity, safety, reliability, and environmental benefits of reduced switching work on the downtown "grid" system. Where possible for P3 work types, planned maintenance, customer or capital work can be bundled together to align with feeders that are taken out of service to create a safe work zone for repairs or equipment replacement which can reduce the switching costs. Due to lower urgency and more flexible turnaround times, P3 work can be aligned with upcoming maintenance, capital, or customer work.

Toronto Hydro has also taken steps to improve work processes in this segment, including: better coordination within the utility to ensure material availability; enhanced inspection forms; and adoption of software tools to improve tracking, management, and reporting of work requests and reduce manual work.

E6.7.4.2 Worst Performing Feeder Segment

Between 2020 to 2022, Toronto Hydro invested $11.7 million in the WPF segment, and projects to invest an additional $12.4 million, for a total of $24.1 million by the end of 2024. The total spend is projected to be slightly less than the $24.9 million forecast in the 2020-2024 DSP, while still generally expecting to meet segment objectives (i.e. meeting or exceeding FESI targets). The WPF segment has proven to be a cost-effective means of managing reliability issues in the short term.

In order to address the evolving needs of customers, for whom reliable service has gained importance, Toronto Hydro needs to invest in this segment at slightly higher rate, for a total of $32.5 million over the 2025-2029 rate period. Some of the main drivers for this are summarized below.

Due to the increased sensitivity of the Outage Management System noted previously, a higher proportion of outage events that occur on the system will be logged, providing Toronto Hydro better visibility into poor performing feeders and actual customer reliability experience. This will enable Toronto Hydro to better mitigate issues and improve service for customers experiencing poor reliability. However, this also requires more investment and will put upward pressure on measures such as FESI-7. Similarly, the new CEMSMI-10 measure provides better visibility into large, sensitive customers experiencing poor reliability (including momentary interruptions), which Toronto Hydro will need to invest in addressing. Finally, due to the recent focus on removing PCBs from the system through programs such as Overhead System Renewal and Underground System Renewal – Horseshoe, Toronto Hydro has been investing less in reliability-focussed proactive renewal of the distribution system, increasing the need for short-term mitigation measures taken through WPF segment.

Toronto Hydro has based its 2025-2029 forecast expenditures for the WPF segment on historical trends and considering the factors noted above. The utility prioritizes WPF scopes based on the reliability performance of each feeder and field patrol findings. The intent of the short-term capital work is to mitigate immediate risk to reliability by replacing or upgrading assets that are at high risk of failure that will result in power outages. Most of this work is targeted for completion within a 12-month period so the outcome of reliability improvement is realized immediately thereafter.

E6.7.5 Options Analysis

E6.7.5.1 Reactive Capital Segment

Toronto Hydro considered three different forecasts for funding the replacement of failed or failing assets for the 2025-2029 rate period:

1) **Lower Bound** – Annual need and costs remain consistently on lower end of historical experience;
2) **Most Likely** – Toronto Hydro's best estimate of needs and costs for this segment based on historical trends and asset condition; or
3) **Upper Bound** – Annual needs and costs reflect higher end of historical experience.

1. Option 1: Lower Bound

As for all three options, this forecast relies on Toronto Hydro's Reactive Capital predictive model to estimate future costs. However, under this option the forecast expenditures in each year are adjusted downward to reflect the assumption that the volume and costs of required work will be consistently on the low end of Toronto Hydro's recent experience with no major storm events or other factors to drive up costs. While it is possible that the required work in one year could drop to this level, it is not very likely and it would be very unrealistic to expect it to stay around that level for a full five-year period.

Implementing this option would very likely result in inadequate funding to meet the demand for reactive capital work based on historical trends. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Addressing reactive capital work through planned capital rebuilds would also take time to plan, design and execute and would not typically allow for the timely replacement of failed and failing assets. Inadequate funding would also increase environmental risk, and safety risks to the public and Toronto Hydro employees. Ultimately this would lead to more interruptions and longer outages for customers, potentially significant legal consequences (e.g. related to environmental obligations), and risk of worker and public safety incidents.

2. Option 2 (Selected Option): Most Likely

The expenditures for this option are forecast using Toronto Hydro's Reactive Capital predictive model and represent the utility's best estimate of required spending in this segment over the 2025-2029 rate period. The proposed investment levels are necessary to maintain system performance and reliability, ensure customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, and mitigate environmental risks.

3. Option 3: Upper Bound

This option is the reverse of Option 1, i.e. the forecast expenditures from the predictive model are adjusted upwards to reflect a scenario where the required work is at the higher end of Toronto Hydro's recent experience. Under this option, Toronto Hydro would also ensure no backlogs of work, while also being in a better position to address any storm events without compromising funding needed for its other capital work. While this would be ideal from a risk management perspective, the extra costs are not prudent given the relatively low likelihood of there being that level of need over the full five-year period.

E6.7.5.2 Worst Performing Feeder Segment

Toronto Hydro considered three alternatives for addressing the WPF segment's budget for the 2025-2029 rate period:

1. Managed deterioration - Reduction of work issued under the WPF segment, addressing asset replacement mainly through planned renewals;
2. Sustainment - Continuation of the current WPF segment, addressing asset replacement at similar levels as seen in the 2020-2024 rate period;
3. Improvement - Enhancement of the WPF segment, addressing asset replacement at higher levels than previously seen in the 2020-2024 rate period (preferred option)

1. Option 1: Managed Deterioration

Under this option, Toronto Hydro would reduce the pace of WPF work. Addressing deficiencies on feeders exhibiting poor reliability mainly through planned capital renewal programs is an adequate solution for the long term, however, planned renewal projects take significantly longer to plan, design and execute; and do not typically allow for the timely mitigation of worsening reliability trends on poorly performing feeders. Additionally, the planned capital renewal programs have recently been focused on the replacement of PCB transformers. Without sufficient targeted, short-term interventions on poorly performing feeders, many customers would likely experience worsening reliability. It is expected that the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers would increase, negatively impacting customers for prolonged periods. This option does not align with the Phase 1 Customer Engagement report conducted in 2022, which identified a growing preference for reliable service, and therefore this option is not recommended.

2. Option 2: Sustainment

Under the sustainment option, Toronto Hydro would continue issuing mitigation work at the current pace, which has proven effective over recent years. However, given the pressures on reliability metrics discussed previously (e.g. recent focus of planned renewal programs on removing PCBs transformers), Toronto Hydro expects that this level of investment will not be sufficient to prevent the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers from increasing. More importantly, some customers will face delays in having their poor reliability addressed and customers have made it clear that reliability is a top priority. Therefore, this option is not recommended.

3. Option 3: Improvement

Under the Improvement option, Toronto Hydro will increase the pace of spending by a small amount in this segment to address pressures on reliability and customer priorities. This option will provide immediate reliability improvements to more customers served by poor performing feeders at a reasonable cost, and serves as a "bridge" solution until planned capital rebuilds can be executed. This option is a reasonable balance of the top customer priorities of price and reliability by spending a little bit more to improve service reliability for those experiencing worse than average performance in the short term, until planned renewal projects can take place.

E6.7.6 Execution Risks & Mitigation

Each segment of the Reactive and Corrective Capital program faces challenges which can delay or prevent work from occurring. Many of these challenges overlap across the two segments of this Program. These challenges are summarized in the table below.

Table 10: Execution Risk Applicability by Segment

Segment	Execution Risks			
	Material Constraints	Resource Constraints	Logistics Constraints	Planned Work Restrictions
Reactive Capital	✓	✓	✓	✗
Worst Performing Feeder	✓	✓	✗	✓

E6.7.6.1 Material Constraints

Both segments use major equipment, which includes but is not limited to, transformers, switches, switchgear, and poles. The procurement lead time for a major asset can vary from 21 days to 14 months based on the type. For this reason, it is difficult and sometimes infeasible to advance or expedite the requests. Supplier shortages affecting material availability may cause delays in executing the work in a timely manner. For more details and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 13 (Supply Chain). To help mitigate this risk, Toronto Hydro orders assets in advance of expected in-service dates and ensures sufficient supply of critical spares.

E6.7.6.2 Resource Constraints

Both segments use design and construction resources. Therefore, if there are insufficient resources to complete all the projects in the Program, certain requests will need to be deferred to ensure highest priority requests are completed. Unpredictable events such as major snow storms or a resurgence of the COVID-19 pandemic could also contribute to lack of construction resources. Furthermore, depending on the location or type of failure, further design, planning, and approval may be required prior to work execution. For example, work may require pole loading, cable pulling or voltage drop calculations by a designer prior to replacing the asset in the field. Toronto Hydro is mitigating this risk with the help of third party (e.g. contractors) to complete any project in excess of Toronto Hydro's resources capacity.

Under the WPF segment, in order to assist with the mitigation of this risk, Toronto Hydro has mapped out the WPF process, where feeder patrols scheduling and timelines for project execution have been clearly established. As a result, mitigation work is normally placed on high priority and scheduled for field execution taking into consideration available resources. Additional emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window.

E6.7.6.3 Logistics Constraints

Reactive Capital work can face challenges such as installation of legacy equipment, lack of space in a vault or feeder not being able to be taken out of service. For these reasons, there is a risk of delay as additional teams may need to be involved for further analysis. Toronto Hydro is mitigating this risk by ensuring clear communication with the overhead or underground renewal portfolios.

E6.7.6.4 Planned Work Restrictions

Under the WPF segment, since this is planned work and is not generally considered to be as urgent as reactive replacements of failed equipment, feeder scheduling restrictions and road work moratoriums may also pose risks to the completion of work in a timely manner. To mitigate this risk, monthly stakeholder meetings are scheduled to review status of work, emerging issues, as well as alternatives to ensure work is completed in a satisfactory manner and time frame.

E7.1 System Enhancements

E7.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 26.3	**2025-2029 Cost ($M):** 151.2
Segments: Contingency Enhancement, Downtown Contingency, System Observability	
Trigger Driver: Reliability	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Financial Performance	

The System Enhancements program (the "Program") is comprised of three strategic investment initiatives that are designed to modify and augment the distribution system, with the goal of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to optimize the efficiency of grid operations and deliver incremental customer value in response to emerging risks and drivers. These drivers include (1) the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); (2) accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and (3) increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).

The System Enhancements program consists of the following three segments:

- **Contingency Enhancement:** This segment enhances Toronto Hydro's ability to optimize the grid and efficiently restore power to customers by: (1) adding remotely operable feeder tie and sectionalizing points on feeders where the number of switching points is currently sub-optimal or where there is an opportunity to facilitate or expand a distribution automation network, (2) upgrading undersized conductors on lateral loops to improve contingency options, and (3) upgrading undersized trunk egress cables. Toronto Hydro plans to invest an estimated $132.9 million in 2025-2029 in Contingency Enhancement, which is a significant increase in segment spending relative to the forecast total for the 2020-2024 period. The increased pace of investment reflects Toronto Hydro's strategic objectives for grid modernization. By 2030, the utility aims to deploy sufficient remote operable switching points to allow for distribution automation across the Horseshoe region, where reliability has typically been more challenging to maintain (compared to the Downtown system) and where significant growth causing system strain is forecasted, particularly in the Horseshoe west region of the distribution system. This segment also introduces modern switching assets that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions. Such devices include but are not limited to reclosers on the trunk and laterals of feeders. Reclosers are pole-mounted breakers which will allow Toronto Hydro to better prevent momentary interruptions from cascading into prolonged outages, and to better isolate a feeder during sustained interruptions, thereby limiting the number of customers impacted by an outage. A fault event on the feeder downstream of the recloser will only cut off power to that section instead of the entire feeder by coordinating with the station breaker, which would primarily benefit those customers that are particularly sensitive to momentary interruptions. Furthermore, installing a recloser on the lateral section of a feeder will provide advanced lateral protection, which prevents temporary faults from becoming sustained outages and avoids momentary interruptions on feeders. The devices proposed under this segment support Toronto Hydro's *Grid Modernization Roadmap*.

- **Downtown Contingency:** This segment provides for plans to add provisions in the downtown core for incremental Toronto Hydro-controlled back-up supply to stations – above and beyond existing Hydro One provisions. Toronto Hydro plans to invest an estimated $13.6 million during the 2025-2029 period in the Downtown Contingency segment. Major loss-of-supply incidents – driven by a variety of causes – have become more frequent in recent years, underscoring for the utility and many of its critical downtown customers (e.g., financial institutions; shopping centres; office towers; large multi-residential buildings; hospitals; etc.) the importance of grid resiliency. The planned enhancements will provide N-2 (i.e., two station loss-of-supply issues at the same time) operational capability to address serious loss-of-supply scenarios. These investments will bring the downtown and horseshoe back-up supply practices into greater alignment with one another, improving resiliency in areas of the system with highly critical loads. The impact of significant outage events in the Downtown core will be of increasing concern to customers and stakeholders as the economy becomes more reliant on electricity in the next decade and beyond.

- **System Observability:** This segment introduces new assets that can provide real-time condition data, loading data and fault-finding capabilities. Such devices include, but are not limited to, overhead and underground sensors, online cable monitors, and transformer monitors as well as considerations for emerging technologies. By installing monitoring on

Toronto Hydro's overhead and underground assets, power outage response times would be improved by the devices' ability to provide alerts and fault localization in real time. The installation of online cable monitors provides real-time thermal profiles of cables, determines actual loading to enhance decision making on loading/connections and provides a better understanding of cable risk. These devices are also beneficial for monitoring cables in locations that require long or costly preparations for inspections. Toronto Hydro plans to invest an estimated $4.7 million in 2025-2029 in System Observability. Overall, these assets are intended to provide real-time or near-real-time information and will expand on pilot programs and focus on system reliability improvements for planned and unplanned scenarios.

The investments in this program represent a substantial portion of the Intelligent Grid component of Toronto Hydro's *Grid Modernization Roadmap*. For more details on the Intelligent Grid strategy, please refer to Exhibit 2B, Section D5.

Overall, Toronto Hydro plans to spend an estimated $151.2 million in this Program over the 2025-2029 period.

E7.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Reducing fault isolation times and the average duration of outages by installing SCADA switches and SCADA-enabled tie and sectionalizing points ○ Reducing the average duration of outages on targeted feeders by installing SCADA-enabled tie and sectionalizing points as well as reclosers; ○ Reducing outages resulting from contingencies by upgrading undersized or de-rated equipment; ○ Using real-time monitoring to detect line disturbance, proactive monitoring of cables, and providing information to identify early signs of failure and to proactively manage the load on the system. • Reduces the impact of downtown Major Event Days (MED) by:

	○ Providing back-up supply for low probability, high impact, long duration station loss-of-supply incidents; ○ Reducing the average duration of outages due to loss-of-supply incidents.
Operational Effectiveness - Safety	• Continues to maintain Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching
Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Leveraging distribution system automation (including real time loading, and remote switching operations) to reduce operational costs associated with patrolling faulted sections of the feeders; ○ Improving power outage response time through real-time power interruption alerts, remote switching operations, and better optimizing resource management (i.e. crews patrolling feeders to identify fault location).

E7.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Operational Constraints, System Efficiency

Toronto Hydro has developed a Grid Modernization Roadmap which aims to (1) leverage technology to improve the efficiency of the grid, and (2) develop capabilities that are responsive to emerging risks and drivers. These drivers include the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).[1]

The System Enhancements program (the "Program") is the most important part of the Intelligent Grid component of the utility's Grid Modernization Roadmap for 2025-2029. It is comprised of three strategic investment initiatives which will modify and augment the distribution system, with the goal

[1] Exhibit 2B, Section D5

of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to achieve sufficient flexibility, automation and resiliency in grid operations.

Investments in the System Enhancements program are necessary to support the utility's system reliability objectives for 2025-2029. Across the system, Toronto Hydro has identified opportunities to maintain and improve reliability and resiliency by implementing targeted system modifications. These system design interventions can cost-effectively mitigate the consequences of failure in many circumstances (i.e. the number of customers affected and outage duration), as distinguished from investments that reduce the probability of failure, such as replacing or maintaining aging and poor condition assets or trimming trees. The investments in this Program will reduce the consequence of failure by improving power restoration capabilities during both normal interruption events and adverse weather events, which are becoming increasingly frequent, as outlined in the Climate and Weather component of the Overview of Distribution Assets for 2025-2029.[2] Other investments in this program will establish capabilities to monitor distribution asset performance and loading in real-time, allowing for early detection of conditions that could warrant proactive interventions to avoid or reduce the impact of failures and violations of system operating parameters.

The following sections discuss each of the three program segments in greater detail.

E7.1.3.1 Contingency Enhancement

This segment includes the following four types of work, three of which are continuations of activities included in Toronto Hydro's 2020-2024 Distribution System Plan:

1. Installing additional SCADA-enabled tie and sectionalizing points in the Horseshoe area in an effort to reduce outage restoration times, improve system resiliency and support Distribution Automation;
2. Installing additional SCADA-enabled tie and sectionalizing points in the open loop overhead areas of the Downtown distribution system in an effort to reduce outage restoration times and improve system resiliency;
3. Upgrading undersized loop conductors in the Horseshoe area; and
4. Upgrading the capacity of trunk egress cables in the Horseshoe area.

Each of these activities is discussed in the following sections.

[2] Exhibit 2B, Section D2.1.2

1. Installing SCADA-enabled Tie and Sectionalizing Points in the Horseshoe area

When a feeder or section of feeder loses power during a contingency event, customers connected to it should receive power from an alternate feeder via feeder tie points and sectionalizing switches. However, if a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing service may not be possible for all customers. This is especially true during peak loading times. Load growth and the addition of new developments can exacerbate this problem as less capacity is available on the feeders. The Contingency Enhancement segment adds tie or sectionalizing points to those feeders lacking sufficient switches.

A secondary issue is the lack of remote operation at some existing tie-points. Before SCADA-controlled devices were available, manual switches were installed. To restore power with manual switches, crews must travel to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, this typically takes one to two hours. In contrast, SCADA-controlled switches will relay instant loading information to the control room, enabling controllers to remotely re-route power to adjacent feeders within minutes. Remotely controlled switches are also safer than manual switches because employees are not exposed to live equipment during manual switching operations.

Toronto Hydro plans to deploy reclosers alongside traditional SCADA switches to eliminate interruptions to sections of customers on a feeder, thereby reducing overall outage times and improving system resiliency. Reclosers provide additional protection to overhead electrical distribution systems by acting as circuit breakers with electronic reclosing capability. By installing a recloser on the trunk of a circuit feeder, it effectively and efficiently contains any temporary or forced outages within that specific section, without affecting upstream customers. Toronto Hydro has successfully piloted reclosers within the distribution system and is ready to roll-out at scale in situations where they will provide necessary incremental benefits to static switches.

Toronto Hydro plans to strategically deploy both reclosers and traditional SCADA switches to enable faster power restoration in the Horseshoe area:

1. Installation of SCADA-enabled tie and sectionalizing points to provide appropriate backup supply; and
2. Installation of reclosers to constrain the impact of an outage to a section of a feeder.

The addition of SCADA controlled tie and sectionalizing switches enables Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. To provide an appropriate back-up supply, Toronto Hydro divides feeders into sections using SCADA-operated switches, where one section serves approximately 700 customers. Each sectionalized portion of the feeder should contain a SCADA tie point that is connected to another feeder. In most instances, to meet this requirement, feeders will require at least three strategically located tie points connected to three unique back up feeders where:

1. The first tie point connects to another feeder from the same substation bus;
2. The second tie point connects to another feeder on a separate bus located at the same substation; and
3. The third tie point connects to another feeder from a different substation.

This configuration ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level, effectively reducing the duration of an outage. During the 2018-2022 period, the average duration for outages on feeders with less than three SCADA tie-points was approximately 707 minutes per year per feeder, whereas the average duration of those feeders with three or more SCACA tie-points was approximately 496 minutes.

Figure 1 below shows a map of Toronto highlighting the location of all the Horseshoe feeders that have less than three SCADA tie points.

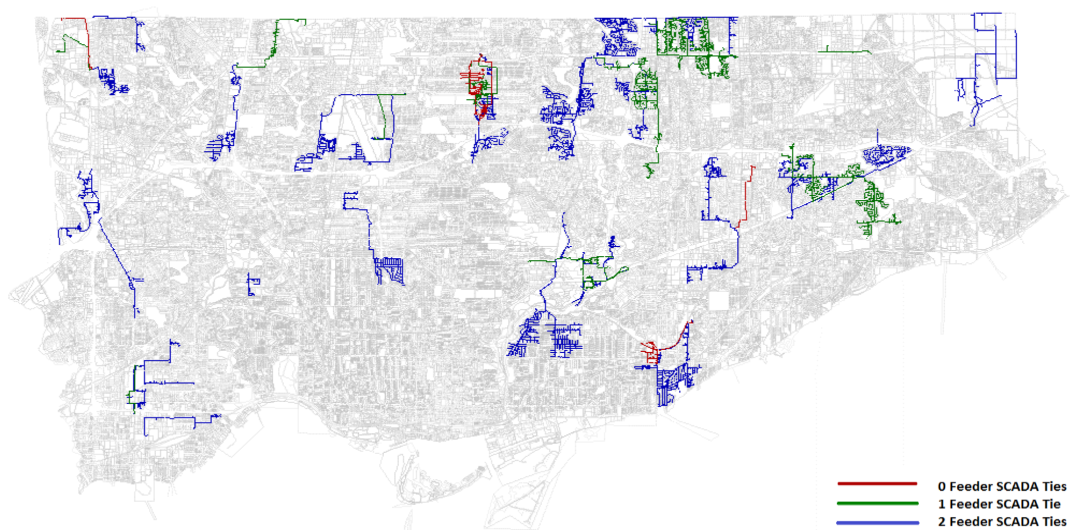


Figure 1: Map of Toronto showing Horseshoe Feeders with less than 3 SCADA Tie Points

Reliability data such as total customer minutes out ("CMO") over the five-year period from 2018-2022 and potential reliability improvement will be the main criteria in determining where the SCADA switch installation work will be carried out. The potential reliability improvement is determined by evaluating the existing SCADA switch condition on a feeder, and what potential improvement could be achieved if the feeder is modified to have a SCADA sectionalizing switch and a SCADA tie switch for every 700 customers connected to the feeder. Figure 2 below illustrates a 25 percent potential reliability improvement when a feeder that has approximately 2,800 customers has been upgraded from its existing condition. The upgrade includes two new SCADA sectionalizing switches to meet Toronto Hydro's Standard Design Practices ("SDP") where approximately 700 customers are to be connected in each section of the feeder. The ability to restore more customers increases following a sustained outage, as more focused isolation of the fault can be achieved.

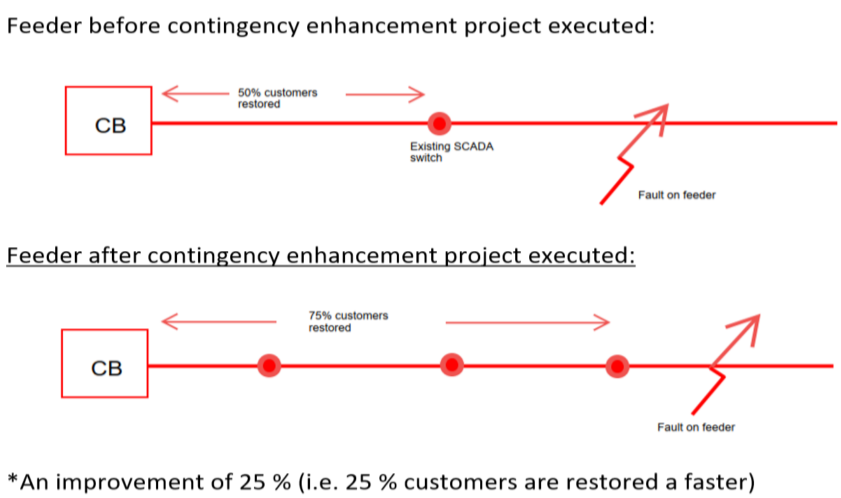


Figure 2: Potential Reliability Improvements Through Contingency Enhancement Investments

During the 2025-2029 period, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in an average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Toronto Hydro intends to install reclosers alongside the installation of other SCADA-switches to enhance the grid's response to outages by containing their impact to a specific section of a feeder.

The recloser introduces new functionality where it will also operate automatically in response to a fault in a coordinated manner such that downstream customers on the faulted section of the feeder will be isolated without interrupting the remainder of the feeder. Figure 3 demonstrates that if a sustained or momentary fault were to occur downstream of a recloser, all customers upstream of that recloser will not experience an outage.

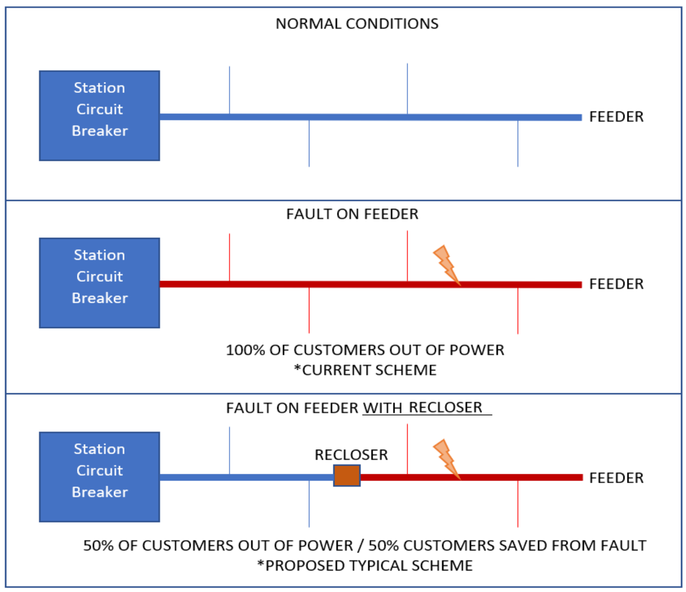


Figure 3: Concept Behaviour of Reclosers in the Distribution System for Sustained and Momentary Faults

The installation of a recloser near the halfway loading point on the circuit feeder trunk will result in significant improvements to MAIFI, SAIFI, SAIDI, and CAIDI. In particular, placing reclosers on the feeder downstream of customers sensitive to power outages can improve power quality as reclosers efficiently respond to downstream faults without impacting upstream customers.

Where coordination is possible, the utility can install multiple reclosers. This will improve reliability by decreasing the number of customers affected by an outage from 50 percent to 33 percent by strategically placing reclosers at the one-third and two-thirds loading points on the feeder trunk.

At a minimum, Toronto Hydro plans to install one recloser per overhead feeder prioritizing those with high historical CMO and CI, high number of customers, and/or on heavily loaded feeders. Based on the results of the recloser pilots, the potential SAIDI improvement is expected to be up to 0.108

minutes per feeder per year. Reclosers also reduce the number of customers experiencing an outage, with a potential SAIFI improvement expected to be up to 0.001 customers per feeder per year.

Additionally, reclosers have intelligent switching capabilities, allowing them to test for faults and voltage sensing on the upstream and downstream portion of the feeder. This enhanced visibility improves outage management and provides incremental information that can be analysed and used for decision-making. These additional features minimize transformer substations faults, extending their useful life; and reduce thermal and mechanical stress on cables, conductors, and connection points will experience less thermal and mechanical stress caused by faults.

Furthermore, the SCADA switch installation work in the Horseshoe will also support Distribution Automation. With the foundational SCADA devices installed, Distribution Automation will be deployed to rapidly isolate a fault and minimize the number of customers affected, without any manual intervention. Distribution Automation requires two main components: SCADA switches, and a Fault Location, Isolation and Service Restoration (FLISR) application. They are as follows:

1. SCADA switches on feeders allow the remote troubleshooting and sectionalizing of feeder faults to achieve more efficient and rapid troubleshooting and restoration, which is the focus of the Distribution Automation work within the Contingency Enhancement segment.

2. FLISR is an application which, together with the Network Management System ("NMS"), can automatically read and process signals from the distribution system to locate a fault. The implementation of Distribution Automation using FLISR would enable Toronto Hydro to rely on autonomous detection and isolation of affected portions

During a feeder level outage, control room operators and crews first work to locate the fault and sectionalize the feeder to isolate the faulted section. This will minimize the impact of the outage to a large portion of the customers before crews are able to identify the root cause of the outage and complete repairs. The use of remote operated SCADA switches reduces the fault isolation time by approximately one hour on average. If a feeder has a recloser and a fault occurs downstream, it can save an upstream customer from experiencing any interruption. The use of FLISR would further improve fault isolation and service restoration by remote operating additional SCADA switches to further sectionalize faulted sections of the feeder and restore healthy portions of the feeder. Figure 4 illustrates the benefits of a feeder with FLISR enabled.

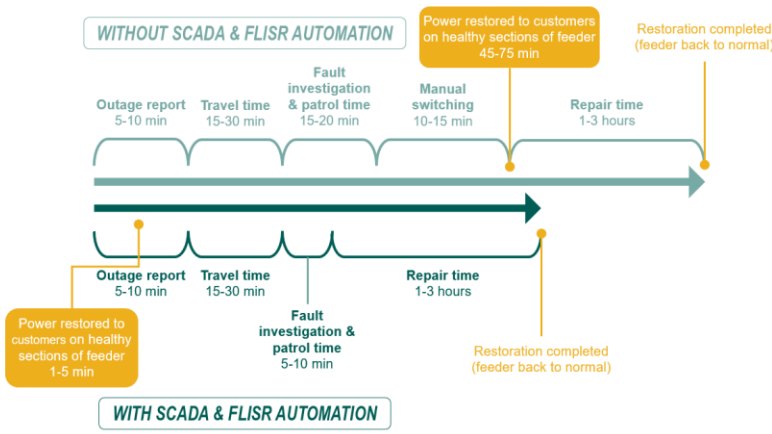


Figure 4: Typical Outage Restoration Times with FLISR VS Without FLISR

In addition, the integration of SCADA switches, reclosers and FLISR has significant benefits and impact on reliability. Figure 5 illustrates the incremental reliability gains for a sustained outage. In the first stage, where only SCADA switches are installed on the feeder, there is no automation and the entire feeder is affected by a fault on the trunk of the feeder. Adding a recloser to the same scenario, automation is introduced and 50 percent of customers will not experience an outage if the fault is downstream of the recloser. In the final scenario, FLISR is implemented in addition to the reclosers and SCADA switches. The three devices will work together to further isolate the fault, activate contingencies and reduce the outage down to 25 percent of the feeder, with the goal of achieving restoration in under one to five minutes.

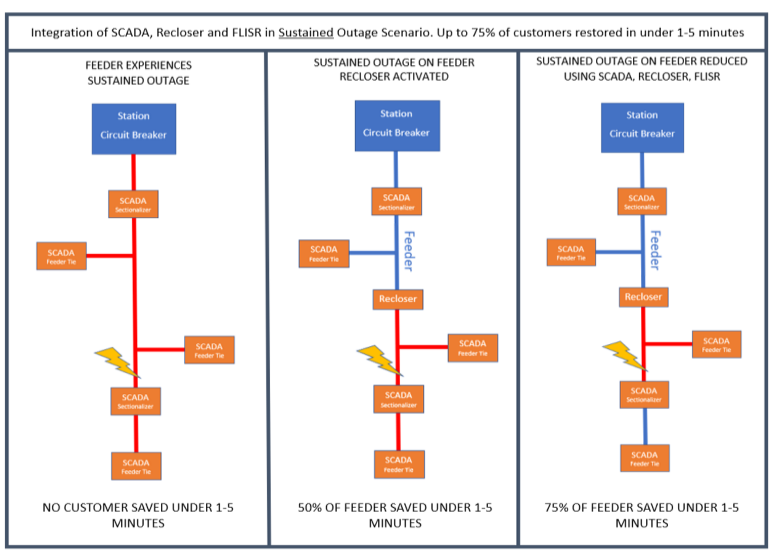


Figure 5: Integration of SCADA, Recloser and FLISR in a Sustained Outage Scenario

Toronto Hydro is focusing the installation of SCADA devices on the trunk feeders on the 27.6 kV distribution network in the Horseshoe area as they have the largest impact on customers. As shown by Figure 6, the 27.6 kV system accounts for the largest share of reliability issues in the system, which also means considerable resources are required to restore outages using manual or remote-operated SCADA switches. Trunk outages interrupt the entire feeder and can impact hundreds to thousands of customers. In contrast, lateral or local outages only impact up to a few hundred customers.

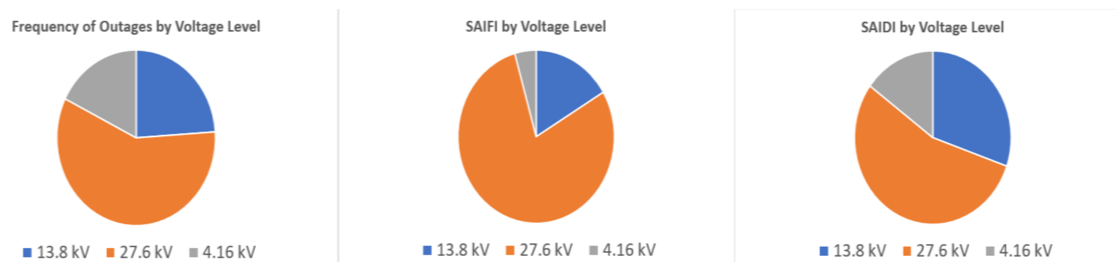


Figure 6: Reliability Impact by Voltage Level – (2018-2022)

Even though trunk outages make up only a third of the outages that occur on 27.6 kV feeders, they can significantly impact SAIFI and SAIDI (as shown in Figure 7 below). The installation of SCADA switches will allow faster sectionalization and restoration of customers in unaffected sections, thereby reducing the impact of trunk outages and improving the reliability of the system.

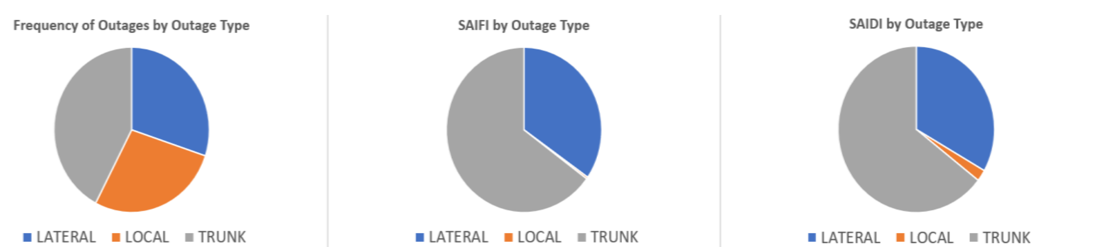


Figure 7: Reliability Impact by Outage Type – (2018-2022)

As of the end of 2022, there are 293 horseshoe feeders of which 230 are considered to be automation ready, defined as having at least two SCADA sectionalizing switches, and at least one SCADA tie point. The switches on these feeders are ready for the implementation of Distribution Automation to realize the full benefits of autonomous restoration. There are 63 Horseshoe feeders that currently do not meet this minimum SCADA switch requirement for Distribution Automation. For these feeders, additional switch installations are required to provide remote restoration capabilities and to enable Distribution Automation to allow for faster outage restorations to customers. During the 2025-2029 period, Toronto Hydro plans to complete SCADA switch installation work on at least 34 of the remaining 63 feeders which will allow all the feeders in the Horseshoe to be able to reap the benefits of Distribution Automation. Ultimately, this will bring the percentage of feeders which meet the Distribution Automation criteria to over 90 percent in the Horseshoe.

The work planned in the Horseshoe area represents the minimum requirement to ensure feeder readiness in support of Toronto Hydro's automatic FLISR schemes. Additionally, the reliability improvements and operational flexibility gained with the proposed plan supports overall performance outcomes related to SAIDI, SAIFI and worst performing feeders. This proposed plan provides the necessary improvements on the Horseshoe feeder trunks and sets the foundation for future system improvements where future SCADA switch installations will provide more visibility and controllability on more specific areas of the system. For example, future opportunities exist to strategically deploy additional SCADA-operated switches:

- To ensure all remaining feeders have no more than 700 customers per section, per Standard Design Practices ("SDP");
- To reduce the number of customers per section in order to reduce customers impacted when a feeder experiences a fault, especially as 700 customers will represent a significant portion of load on a feeder with each customer;
- On riser poles where the main feeder transitions from overhead to underground and vice versa, to increase fault locating capabilities and add the ability to isolate and test reclose if a suspected fault is on the underground segments through targeting approximately 3444 OH-UG Non-SCADA riser points;
- On riser poles at egress cable risers or at the overhead conductor exiting from the station to have the ability to independently remote operate the first switching device and isolate the entire feeder; and
- On riser poles at expressway/highway crossings where high salt contaminated areas exist and SCADA switches have been able to provide much higher operability and are more resilient when compared to manual switches.

2. Installing SCADA-enabled Tie and Sectionalizing Points in the Downtown area

During the 2015-2019 period and 2020-2024 period, the scope of work for Contingency

Enhancement included installing SCADA-enabled tie and sectionalizing switches for the 27.6 kV Horseshoe distribution system in an effort to reduce outage duration and to support Distribution Automation. The Downtown distribution system is inherently more reliable than the Horseshoe since it is predominantly underground and uses supply configurations like Dual Radial which reserves dedicated standby capacity and the Secondary Grid Network which results in no interruptions to customers under contingency. However, the Downtown distribution system does include overhead feeders that are similar to the Horseshoe which is an open loop distribution system. Toronto Hydro anticipates that the impact of outages in Downtown Toronto will be of increasing concern to customers as they become more reliant on electricity thus increasing the need for greater resiliency to the power supply. As determined through Phase I Customer Engagement results, there is generally support among customers for investments in new technology to improve the system.[3] To address these concerns and improve the resiliency of the power supply in the Downtown core, Toronto Hydro plans to expand the scope of Contingency Enhancement investments to include SCADA switch installations on the open loop overhead feeders in the Downtown distribution system.

During the 2025-2029 period, Toronto Hydro plans to install a total of 93 SCADA switches on 40 overhead feeders in the Downtown area. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

3. Upgrading undersized loop conductors in the Horseshoe area

Figure 8 depicts a typical looped distribution lateral supplying a series of transformers off the main trunk portion of a feeder. There is an open point near the middle of the loop so that, under normal operating conditions, approximately half of the load in the loop is supplied from one lateral or the other.

[3] See Customer Engagement – Exhibit 1B, Tab 5, Schedule 1

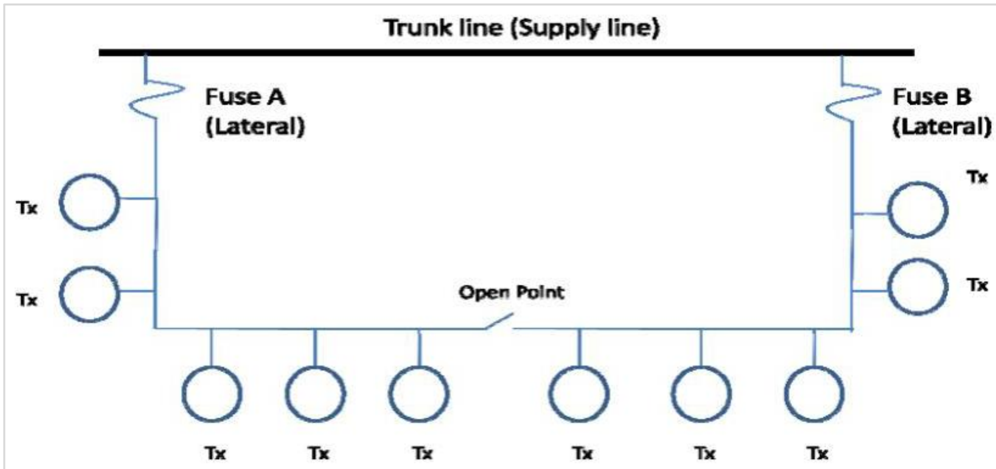


Figure 8: Looped Distribution Design

The conductor on either lateral is designed to be large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs on the first section downstream of Fuse B, the load must be supplied entirely from the other side of the loop, as shown in Figure 9.

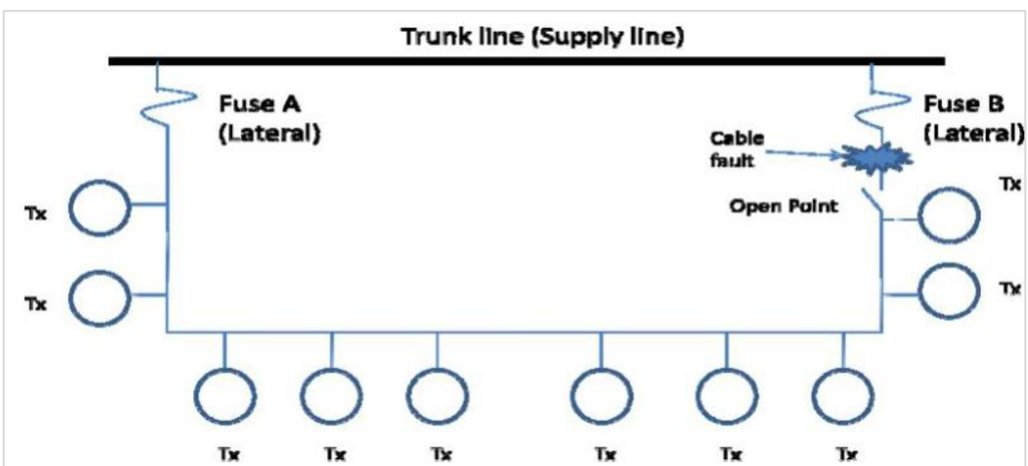


Figure 9: Power restoration in loop after a fault has occurred

Gradual increases in load in certain areas have resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop. Controllers monitor the conductor size and number of transformers transferred to the circuit under contingency; however, the actual load on each transformer may not be known by the controller in real-time.

Toronto Hydro plans to upgrade undersized conductors in lateral loops that are smaller than the utility's standard loop sized conductors during the 2025-2029 period to ensure that they are rated to carry the load of the entire loop under contingency conditions.

3. Upgrading the Capacity of Trunk Egress Cable

Toronto Hydro plans to replace legacy aluminum cable on feeder trunk egress sections with copper cable. The initial section of a feeder, between the station breaker and the first distribution switch (i.e. the section upstream from any load connections), is called the "egress". The egress cable must be adequately sized to supply the load of the feeder, plus any additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker (i.e. 600 A).

Some egress cable installed in the 1960s and 1970s on 27.6 kV feeders is 1000 kcmil aluminum, a cable type that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment, to 500 A in summer and 530 A in winter. In some areas, load growth has exceeded the capacity of this existing configuration. Under contingency, a feeder is required to carry the load of adjacent feeder sections that connect to it. Thus, it is critical that the maximum capacity of the feeder is utilized to restore as many customers as possible. This poses a high-risk situation, as failure of the load-carrying feeder to deliver power to its maximum capacity may result in loss of power to two other feeders, causing outages to a large area for four hours (or more) that it would take to make repairs. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency would experience an outage until the work on their normal feeder has been completed. For these reasons, it is critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker.

Under a contingency condition, controllers may not be able to utilize feeders with a 1000 kcmil aluminum egress trunk cable to pick up load lost on adjacent feeders during a fault or planned maintenance. As a result, affected customers will experience a prolonged power outage until the faulted asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions and further reducing reliability.

As of the end of 2022, there are 11 Horseshoe stations with a total of 88 km of egress cable considered under-rated (i.e. not standard 1000 kcmil copper). Table 4 below shows the amount of under-rated cable for each of these stations. During the 2025-2029 period, Toronto Hydro will prioritize doing work on feeders that have experienced the most customer minutes out over a five-year period and for feeders where the peak loading of their tied feeder is greater than the capacity of the aluminum egress cable. These targeted upgrades and installations will better equip the distribution system to meet the needs of customers in contingency scenarios and more effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk.

Table 4. Stations with Under-Rated Trunk Egress Cable.

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Bermondsey TS	22	23.3
Runnymede TS	1	14.6
Leslie TS	18	23.9
Agincourt TS	7	8.0
Fairchild TS	13	26.5
Bathurst TS	10	48.2
Rexdale TS	3	9.1
Cavanaugh TS	7	13.1
Fairbanks TS	2	9.7
Finch TS	4	20.1
Scarborough TS	1	7.5
Total	**88**	**203.9**

E7.1.3.2 Downtown Contingency

The Downtown Contingency segment is designed to mitigate the risk of high impact, long duration station supply failures. While the likelihood of a long duration loss-of-supply incident occurring in any given station in any particular year is low, these events do continue to occur. Long duration outages are particularly consequential because critical customer loads such as major financial institutions, hospitals and universities are concentrated in the downtown core.

Between 2003 and 2022, there were 34 major outages directly associated with loss of supply incidents. The typical causes of these outages include foreign interference, transmission equipment failure and station flooding. Most recently, on August 11, 2022, a barge moving a crane in an upright position ran into high-voltage transmission lines in the Port Lands. This incident caused three Hydro One power lines to fail causing loss of supply at three Toronto Hydro stations: Esplanade, George &

Duke, and Terauley, impacting 1,633 customers including local businesses, hospitals, office spaces, and the Eaton Centre. All customers were restored within 6.5 hours of the event. The table below outlines other recent examples of loss of supply incidents. The interstation switchgear ties work proposed in this segment specifically targets the stations impacted by the August 2022 incident.

Table 5: Examples of Major Loss of Supply Events from 2003 to 2022

Event	Description
Loss of Supply (July, 2005)	• 115kV pole and line H5E from Hearn failed • 24,572 Customers interrupted • 4,610,141 Customer minutes out • The last customer restored after 18 hours and 50 minutes
Foreign Interference (January, 2005)	• Station flooding due to broken city water main • 3,556 Customers Interrupted • 2,304,288 Customer minutes out • The last customer restored after 10 hours 48 minutes
CB Failure (July, 2012)	• Circuit Breaker failed causing bus differential trip • 4,565 Customers Interrupted • 1,901,191 Customers minutes out • The last Customer restored after 6 hours and 57 minutes
Loss of Supply (August, 2022)	• Loss of Supply due to crane contact with 115kV lines • 11,183 Customers Interrupted • 2,789,920 Customer minutes out • The last Customer restored after 6 hours 34 minutes

Table 6: Downtown Stations at Risk

Downtown Stations	
Basin	Gerrard
Bridgman	Glengrove
Carlaw	Highlevel
Cecil	Leaside
Charles	Main
Copeland	Strachan
Dufferin	Terauley
Duplex	Wiltshire
Esplanade	Windsor

George and Duke	

The period between 2003 and 2022 saw more incidents than the previous decades. As such, to maximize the benefit of investments in the Program, it is appropriate to target the downtown area through the Downtown Contingency segment. To demonstrate the potential reliability benefits of these Downtown Contingency investments, it is helpful to consider the impacts on customer interruption over the 2003-2022 period had full Downtown Contingency been in place during that period.

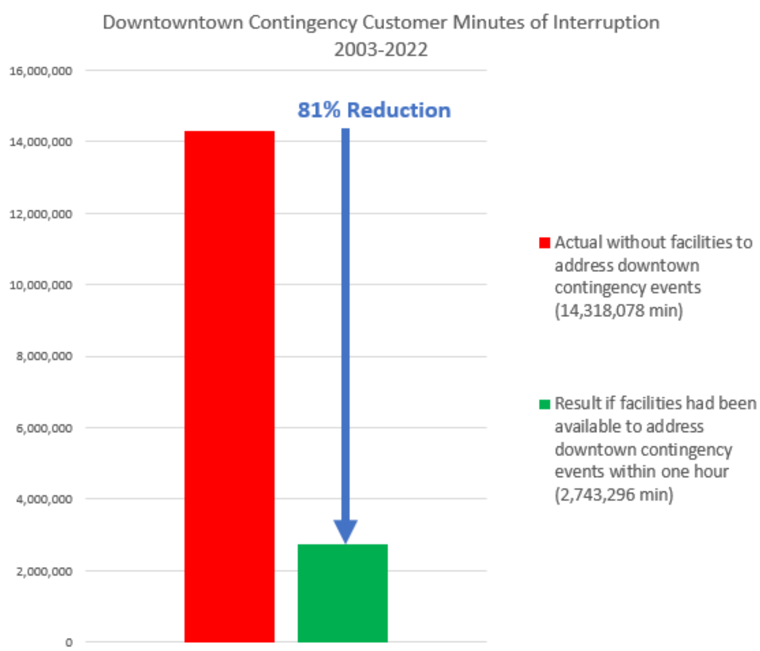


Figure 10: Reliability impact of downtown station load transfer implementation

The operationalization of a Downtown Contingency program with the ability to pick-up customer loads from another station within one hour, could result in an approximately 80 percent reduction in Customer Minutes of Interruption caused by such incidents.

Following the occurrence of downtown contingency incidents, Toronto Hydro analyzes the cause and undertakes projects in an effort to minimize the risk of reoccurrence. Examples of station improvements include: hardening station facilities and equipment to be able to withstand externally and internally-driven failure modes, additional sensors and alarms that can identify developing incidents at the earliest opportunity, and high-volume sump pumps that can address major water entry incidents such as city water main breaks. As a result, the risks of long duration station supply failures have continued to drop over time. However, although these projects reduce the risks, they often cannot be entirely eliminated. Risks outside of Toronto Hydro's control, such as the recent crane contact with Hydro One lines incident, will therefore cause an increasing proportion of long duration station outage incidents in future years. Concerning the nineteen long duration outage events in 2002-2022 that could be addressed by downtown contingency enhancements, sixteen were due to causes outside of Toronto Hydro's control, or approximately 84 percent.

Contingency enhancement options include a variety of methods to install ties between stations. Including:

- Interstation switchgear ties (i.e., ties between buses in different stations)
- Intrastation switchgear ties (i.e., ties between buses in the same station)
- Interstation feeder ties
- Automated Primary Closed Loop (APCL) ties

Ideally, each station switchgear would have sufficient emergency loading capability to pick-up all, or most, of an interconnected switchgear's load. In addition, each station would also ideally be connected to a different Hydro One source of supply.

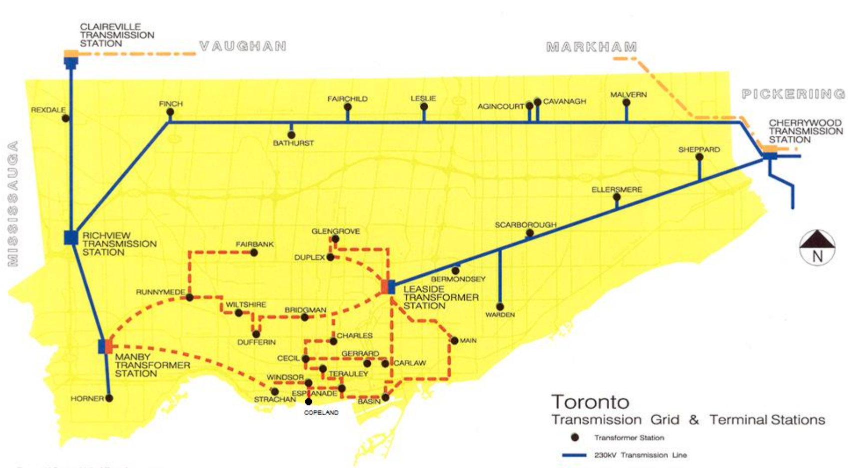


Figure 11: Map of Toronto stations with Hydro One transmission connection

To achieve these benefits, Toronto Hydro has chosen the medium-term plan to provide interstation switchgear ties.

The proposed ties will cover the stations that were impacted by the 2022 crane contact incident, where the best option for an anchor downtown source is Copeland Station. This station has a switchgear designed for load transfer purposes, as well as an extra transformer available for emergencies. Additionally, future plans include replacing the initial 115 kV transmission connection with a 230-kV connection. This means that Copeland Station will ultimately have a Hydro One source of supply well-separated from those supplying all other nearby downtown stations. When combined, these factors make Copeland Station by far the best choice for an anchor source in the downtown area.

E7.1.3.3 System Observability

An important component of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029 is the targeted deployment of technologies that will enhance grid transparency. An overview of these investments is provided in the System Observability category of the utility's Grid Modernization Roadmap (See Exhibit 2B, Section D5). From a materiality perspective, the most significant investment Toronto Hydro is making to enhance grid transparency in the 2025-2029 period is the replacement of end-of-life, legacy smart meters with next generation smart meters ("AMI 2.0").[4] AMI 2.0 has the long-term potential to provide many of the high frequency, multi-parameter insights that will be required to address the operational pressures and requirements expected as electrification and DER proliferation ramps-up. However, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in incremental data analytics, digital systems integrations, and business process changes. It is not yet apparent which of these potential AMI-based solutions will prove to be more economical and sustainable as compared to more use-case-specific grid sensor technologies which are currently more proven and available. In light of this uncertainty, and in the interest of providing immediate benefits to customers while diversifying the long-term options available to Toronto Hydro for monitoring the system, the utility is introducing the System Observability segment for 2025-2029.

This segment will involve the strategic deployment of sensors that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid. These capabilities will provide Toronto Hydro with two primary benefits: enhanced response capabilities through the use of fault finding sensors and other

[4] For more details about Toronto Hydro's AMI 2.0 investments, please refer to the Metering program in Exhibit 2B, Section E5.4

telemetry; and the ability to make more effective capital investment and maintenance planning decisions.

To achieve these benefits, the System Observability segment will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors.

1. Overhead and Underground Sensors

Overhead and underground sensors can improve Toronto Hydro's outage response time. As of today, Toronto Hydro depends in large part on customers to notify the utility when there is a localized outage. The most impactful use-case for grid sensors is that they can eliminate extra steps in the process by alerting the control room to an outage in real time so the utility does not have to wait for notification from a customer. With the mature directional sensor capabilities that are now available, Toronto Hydro can cost-effectively introduce and expand visibility to parts of the grid where it has not traditionally been available.

Additionally, overhead and underground sensors enable controllers and dispatch crews to narrow locations of faults, effectively reducing outage response times. They may also aid in helping verify the cause of outages. As a subsequent need, overhead and underground sensors and monitors provide data that enable Toronto Hydro to record information for diagnostic purposes and drive towards proactive asset management to improve SAIFI & SAIDI metrics. Data can also be extracted to find core failure causes and address them proactively. Figure 12 illustrates sensors on overhead lines that could be part of the System Observability investments.

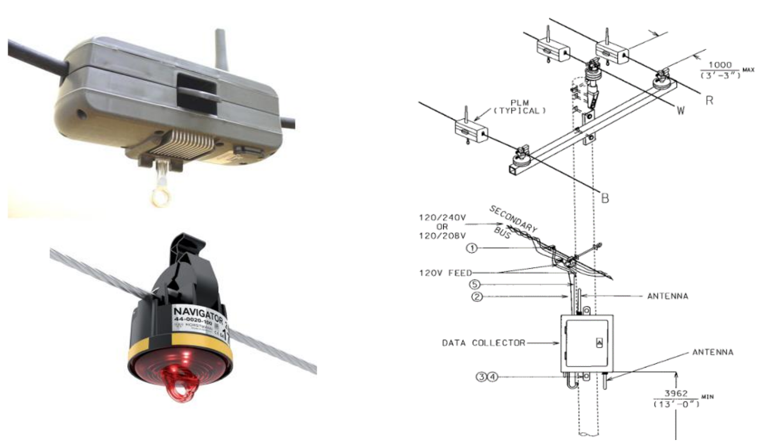


Figure 12: Illustration of Sensors on Overhead Lines

2. Online Cable Monitoring

Online Cable Monitoring utilizes distributed temperature sensing (DTS) technology to obtain a continuous temperature profile of fiber optic cables that are placed alongside underground cables. This information will enable operations and planners to understand feeder loading, increase asset utilization, and identify hot spots. Online Cable Monitoring would allow for proactive measures to be taken on cables such as identifying cables that could be at risk of failure before failure or costly to inspect otherwise. Furthermore, Online Cable Monitors allow for monitoring of load growth and for Toronto Hydro to proactively address and prioritize capacity availability. Lastly, Online Cable Monitors would save OPEX costs and planned outage times when it comes to cable testing and diagnostics. Toronto Hydro plans to deploy Online Cable Monitoring using DTS to complement diagnostic testing as part of Toronto Hydro’s cable testing program in order to achieve a better understanding of the overall underground cable system. Currently, limited and targeted cables go through a lengthy and manual testing process of partial discharge which has been cumbersome. Figure 13 illustrates example online cable monitoring devices that could be part of the System Observability investments.

Figure 13: Illustration of Online Cable Monitoring Devices

Online cable monitoring may be deployed in parts of the distribution system that have physical constraints and associated processes to access. One example includes assets within the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water, making it costly to inspect or maintain.

3. Transformer Monitoring

With the increasing rate of adoption of electric vehicles and increases in residential density in the City of Toronto, there is more pressure due to higher load demand on Toronto Hydro's secondary distribution system. Transformer monitoring allows Toronto Hydro to gain more accurate, real-time loading on the transformer instead of aggregating customer meter loading. The data these devices provide will help improve design requirements when considering new and existing secondary distribution systems. These monitors are also expected to help improve the understanding on the impact of unmetered services on the secondary distribution system to refine connection strategies. The data obtained will also help refine asset management strategies for distribution transformers and optimize their usage and life. An example transformer monitor is shown in Figure 14.

Figure 14: Illustration of a Transformer Monitoring Device

The System Enhancements program segments work together towards the goal of achieving Toronto Hydro's vision of an Intelligent Grid. The continued implementation and enhancement of the Contingency Enhancement segment and the introduction of the System Observability segment specifically contribute to the Intelligent Grid components shown in Figure 15. As key components of the Intelligent Grid, being able to fully implement the System Enhancements program is essential to the overall success of the Intelligent Grid initiative.

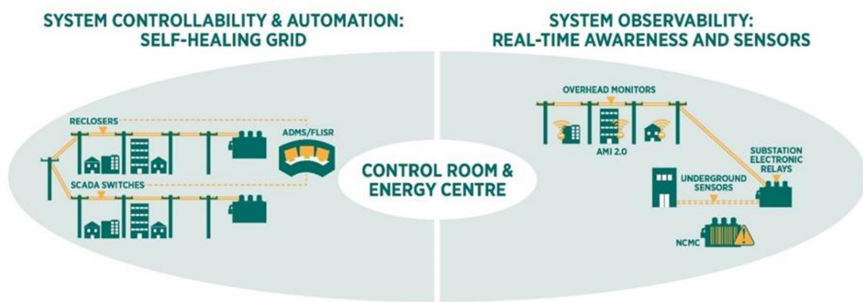


Figure 15: Intelligent Grid Components

E7.1.4 Expenditure Plan

To meet its objectives for an intelligent grid, Toronto Hydro plans to invest $151.2 million over the 2025-2029 period in the System Enhancements program.

Table 6: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Contingency Enhancement	5.0	0.8	4.9	3.7	5.5	17.0	19.6	32.0	29.0	35.3
Downtown Contingency	-	3.7	1.7	-	0.1	1.7	2.9	2.9	3.0	3.1
Customer-Owned Substation Protection	-	0.7	0.1	-	-	-	-	-	-	-
System Observability	-	-	-	-	0.1	0.8	0.9	1.0	1.0	1.0
Total	**5.1**	**5.1**	**6.7**	**3.7**	**5.7**	**19.6**	**23.3**	**35.9**	**33.0**	**39.4**

E7.1.4.1 Contingency Enhancement

1. 2020-2024 Variance Analysis

Toronto Hydro invested $10.7 million in the Contingency Enhancement segment from 2020-2022 period and is projected to allocate an additional $9.2 million in 2023-2024, totalling $19.9 million. This is 25.1 percent lower than the initial proposal outlined in Toronto Hydro's 2020-2024 Distribution System Plan ($24.9 million).

Due to the necessity of installing connections between Copeland TS and Windsor TS in the 2020-2022 period, $5.5 million from the Contingency Enhancement segment was reallocated to Downtown Contingency (see variance analysis below). As a result, planned cable upgrades at Bermondsey TS, Fairbank TS, and Leslie TS were deferred to the 2025-2029 rate period. These entail the replacement of over 4,000 meters of aluminum egress cable with the latest standard copper cable.

Between 2020 and 2022, Toronto Hydro added tie points to 5 feeders, sectionalizing points on 9 feeders, and upgraded one undersized lateral loop. These investments brought 3 feeders up to the minimum Standard Design Practice for operating contingency and prepared three additional feeders for Distribution Automation. Note that a typical Horseshoe feeder serves between 1,400 and 6,000 customers.

For 2023 and 2024, Toronto Hydro plans to install tie points on four distribution feeders and sectionalizing points on three feeders.

2. 2025-2029 Proposed Plan

Toronto Hydro intends to invest approximately $132.9 million in Contingency Enhancement projects during the 2025-2029 period. This increase in expenditure, relative to the 2020-2024 levels, is informed by customer priorities for reliability where they indicated outage durations, particularly during extreme weather events, to be of high importance. Small business and residential customers, in particular, expressed a strong preference for investment in new technology.[5]

Therefore, over the 2025-2029 period in total, Toronto Hydro plans to install approximately 300 SCADA switches (at a pace of 60 per year) on feeders across the Horseshoe and Downtown area with the highest total Customer Minutes Out (“CMO”) during the latest 5-year period. As stated in Section E7.1.3.1, this is intended to achieve a total of 18 percent improvement in reliability across 90 Horseshoe feeders and 29 percent on 40 Downtown feeders. This will ensure the remaining 63 Horseshoe feeders meet the distribution automation requirement, thus enabling Toronto Hydro’s Grid Modernization objectives.

Specifically, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent

[5] *Supra* note 3

reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Furthermore, Toronto Hydro plans to install a total of 94 SCADA switches on 40 overhead feeders in the Downtown area during the 2025-2029 period. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

In addition, this investment option plans to install 220 modern reclosers in the distribution system which will yield improved service reliability, a reduction in CMO and CI, and operational efficiency advantages over fault management as stated in Toronto Hydro's Grid Modernization Roadmap (Exhibit 2B, Section D5).

Moreover, this investment initiative will replace approximately 70 km of undersized cable which makes up approximately 80 percent of the total existing undersized egress cables in the Horseshoe area where the peak loading under contingency situation exceeds the capacity of the aluminum egress cable.

Investments made within this segment will be prioritized on the basis of historical reliability performance, loading statistics, cost-benefit analysis, and other relevant data.

E7.1.4.2 Downtown Contingency

In the 2015-2019 rate period, Toronto Hydro's Downtown Contingency program provided station level contingency through load transfer capabilities between stations in the downtown area to mitigate loss of supply risks. Toronto Hydro successfully completed a number of overheard feeder ties, but upon re-evaluating the costs and challenges associated with underground feeder ties, the utility decided not to pursue additional work in this program. However, over the 2020-2022 period, Toronto Hydro spent $5.5 million and installed interstation switchgear ties between Copeland and Windsor stations due to the need to provide contingency mitigation in the downtown core. This work enabled:

- Contingency mitigation at Copeland TS due to the need for transformer repair. These bus ties ensured that should an equipment failure occur, customers supplied by Copeland would not experience an extended power outage.
- Transfer load from Windsor station switchgear to enable switchgear upgrade projects. This work will require the Copeland to Windsor ties to be modified multiple times in the near future. These will provide downtown contingency capability between Copeland and Windsor stations in the long-term.

Recent loss-of-supply incidents have resulted in Toronto Hydro proposing an interstation switchgear tie project from Copeland Station to Esplanade Station over the 2025-2029. The Copeland-Esplanade project work will progress from inspection to design to civil construction and finally electrical construction. Following this window, additional options should become available and are discussed in the next section.

E7.1.4.3 System Observability

The System Observability segment is a new segment with no planned investments in the 2020-2024 DSP. However, Toronto Hydro now plans to spend approximately $0.1 million in 2024 to start installing sensors and monitors before ramping up to $0.9 million per year on average over the 2025-2029 period.

Over the 2020-2022 period, Toronto Hydro assessed a number of overhead and underground sensors and monitors. Over the course of 2023 and 2024, the utility intends to issue a request for proposal to evaluate and select the technology best suited for Toronto Hydro’s system.

Once completed, these sensors and monitors will be installed on the overhead and underground system during the 2025-2029 period at a steady pace with ramp up starting in 2024. Priority would be given to areas that are forecasted to increase in load (such as Electric Vehicle growth, electric heating, etc.) and in areas that inspections are costly such as the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water.

The utility also plans to pilot transformer monitors to validate transformer readings in order to support planning analyses and enhance policy planning decisions. Toronto Hydro intends to pilot transformer monitors across the City of Toronto in various settings to obtain samples of data that are representative of the many different scenarios. The results of the pilot and additional functionality determined will drive future plans and expenditures.

E7.1.5 Options Analysis

E7.1.5.1 Options for Contingency Enhancement

1. **Option 1: Contingency Enhancement at Current pace**

Under this option, Toronto Hydro would continue investing at the current pace to spend approximately $20 million over 2025-2029. This would severely limit the scope of work that can be accomplished. Toronto Hydro would have to prioritize only the most critical Contingency Enhancement investments, such as installing 111 SCADA switches for 37 of the feeders in the Horseshoe with the worst reliability and approximately 17.8 km of undersized egress cable upgrades for 7 feeders. The utility would not be able to install SCADA switches on a portion of the Horseshoe feeders that currently fail to meet the minimum Distribution Automation requirement or on overhead Downtown feeders. This option also excludes the implementation of modern reclosers in the distribution system and any upgrades of undersized loop conductors.

Under this option, the utility's ability to reduce the number of customers impacted and outage duration during contingency events would be limited. Moreover, the absence of strategically placed reclosers would leave Toronto Hydro's assets susceptible to damage and strain during system faults. Without the fault testing capabilities provided by recloser features, Toronto Hydro would be constrained in its ability to proactively prevent faults. Considering these factors, the status quo is not recommended.

2. **Option 2 (Selected Option): Contingency Enhancement**

Executing the proposed Program would strengthen Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. This investment option entails upgrading approximately 300 SCADA switches for 94 Horseshoe feeders and for 40 Downtown feeders. Furthermore, 44 feeders will be targeted for upgrading undersized egress cables from aluminum to copper, replacing approximately 69 km of cable. These enhancements align with Toronto Hydro's Grid Modernization plan, ensuring that 90% of Horseshoe feeders meet the Distribution Automation requirement by the end of the period.

Additionally, this investment option will include implementing 220 modern reclosers in the distribution system that will yield improved service reliability, a reduction in Customer Minutes Out (CMO), and operational efficiency advantages over fault management. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, especially in the Horseshoe and Downtown areas, including high-impact contingency events. This option offers short-term and long-term benefits, directly benefitting customers and prolonging the life of system assets. Therefore, this option is highly recommended as it strikes a balance between mitigating risks and meeting customer expectations. It aligns with Toronto Hydro's Grid Modernization goals.

E7.1.5.2 Options for Downtown Contingency

1. **Option 1: Maintain the status quo**

This option maintains the system at status quo. Projects would continue within the Stations portfolio to eliminate downtown reliability risks and to install new equipment which meet the latest standards; reducing vulnerabilities and improving flexibility in emergency situations. Distribution projects that allow customer load transfer between stations during major station outages will be pursued. While these investments would improve reliability risks within the system, they do not mitigate contingency event scenarios. And therefore, this option is not recommended.

These ongoing incremental improvements will continue into the future regardless of other options being undertaken.

2. **Option 2 (Selected Option): Station-to-Station switchgear ties (i.e. interstation switchgear ties)**

This option involves the installation of station-to-station switchgear ties on eligible stations with the required 3000A feeder positions present. Each station switchgear should have sufficient emergency loading capability to pick-up the majority of an interconnected switchgear's load. Additionally, each station should be connected to a different Hydro One source of supply. This option is the selected option as it would provide the quickest timeline to achieve reliability benefits, while accommodating operational constraints.

As noted in E7.1.3.2, the best option for an anchor downtown source is Copeland Station.

3. Option 3: Station-to-Station feeder ties

This option involves the installation of station-to-station *feeder* ties, and would need to continue into the future in order to maximize benefits. It requires a long time to achieve the stated benefits compared to the previous options. However, the result would provide more benefits.

The feeders should have sufficient emergency loading capability to pick-up the majority of the neighbouring feeder's load and a different Hydro One source of supply. There are approximately 557 feeders in the downtown area suitable for feeder ties, of which 26 have already been tied.

To complete the required feeder ties in a reasonable time frame, this option requires installation of approximately 11 feeder ties annually, for a period of approximately 25 years.

Feeder ties provide limited ability to pick-up loads; therefore, if required, the Control Room would have to select the loads to pick-up out of the options available. The Control Room would be required to prioritize loads such as hospitals, water and sewage treatment, and key financial centers.

Interstation feeder tie projects were undertaken in the 2015-2019 period, but were found to have escalating costs and challenges as noted in 2020 CIR (Section E4.2.3 at, pg. 12-13). Due to the relatively high costs for the benefits achieved, this option is not recommended.

4. Option 4: Switchgear ties within the same station (i.e. intrastation switchgear ties)

This option involves the installation of direct bus ties between switchgears in the same station. These ties can be used to resupply a Toronto Hydro station switchgear that has lost its Hydro One supply, from another Toronto Hydro switchgear within the same station that continues to be supplied by Hydro One.

This work is in the Stations portfolio and will not be undertaken in the downtown contingency segment. In this option, when existing Toronto Hydro station switchgear are replaced, the new switchgear includes provisions for direct bus ties to other switchgear within the same station.

5. Option 5: Automated Primary Closed Loop ties (i.e. APCL ties).

The Automated Primary Closed Loop ("APCL") option provides the most substantial long-term improvements of all the options. It also increases development risks and challenges.

This option involves the installation of station-to-station *feeder* ties. Unlike Option 3, this option involves the addition of components to tie future APCL distribution systems supplied by two different stations. APCL equipment and system design are currently in development, with no plant presently installed in the field. Over the 2023-2025 period, the first prototype APCL vault equipment is expected to be acquired and will be used to develop and test protection and control, as well as operational practices. APCL ties provide fundamentally more cost effective and operational benefits than other options.

This option requires a longer timeline to achieve a specified level of benefits than other options. However, it would achieve more benefits at a lower cost. Ultimately, APCL will not be achievable in the 2025-2029-time frame, but will be considered for future distribution system plans.

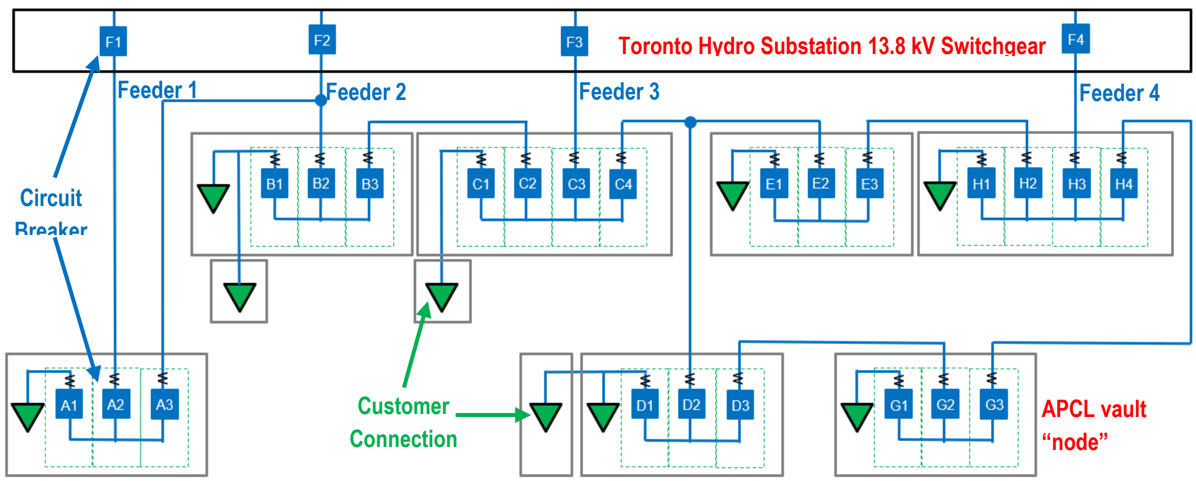


Figure 16: APCL Distribution System

E7.1.5.3 E7.1.5.3 Options for System Observability

1. Option 1: No Installation of System Observability Assets

The present circumstances, being a system without visibility on live data, is costly and timely to customers when it comes to outage restoration. Acknowledging that proven technology is readily available, the existing costs and existing average outage durations are avoidable and capable of being reduced. Without the thermal profiles and partial discharge identifying capabilities through online cable monitors, proactive measures cannot be taken which are costly and preventable. The current system waits for cables to fail and then Toronto Hydro reacts accordingly which is costly and untimely. For these reasons, this option is not recommended.

2. Option 2 (Selected Option): Installation of System Observability Assets

Installing monitoring devices onto Toronto Hydro's existing system will enable visibility on the electrical grid at strategic locations and would be a win-win for customers and Toronto Hydro, and is the recommended option. Observability would provide reduced outage times, extended asset life and improved planning in many cases. Costs can be reduced by less time identifying the fault and less wear-and-tear on equipment that occurs during fault. Without observability assets, manual inspections are undertaken which may not be frequent or sufficient to identify developing issues prior to failure. Online cable monitors and transformer monitors provide a paramount overview of risk failure. This initiative for visibility on faults coupled with communication to Toronto Hydro's controllers and crews is the recommended option.

E7.1.6 Execution Risks & Mitigation

E7.1.6.1 Contingency Enhancement

Unforeseen site conditions, such as the presence of third-party infrastructure (e.g. gas, sewer or water pipes), can necessitate scope changes, and result in cost increases or delays in the completion of the underground cable replacement Contingency Enhancement work. In these situations, Toronto Hydro will reprioritize or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must consider city road moratoriums. Underground cable replacement work which is part of this segment might come in direct conflict with city-imposed road moratoriums. This could delay any civil infrastructure installation required for cable upgrades which will delay the Contingency Enhancement projects. Toronto Hydro will mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Distribution Automation projects, by their nature, require robust communication between SCADA switches. Under the proposed centralized approach (FLISR) utilizing the NMS, this risk will be mitigated.

Supply chain challenges is a new risk that Toronto Hydro is currently experiencing where many of the vendors cannot provide material and equipment on time to ensure timely execution and completion of Contingency Enhancement projects. This can be mitigated by working closely with the supply chain team to order as much of the required material in advance, and to reprioritize the order of which projects get executed each year to minimize disruption to the work program for this segment during 2025-2029 period.

Based on Toronto Hydro's recloser pilot, reclosers require coordination with HONI, System Studies, and Operations to make the reclosers coordinate and operate properly. Without proper coordination between the station circuit breaker and the recloser, there is a risk that both devices will trip resulting in minimal benefits from the recloser. Modern reclosers compatible with Toronto Hydro's system require microprocessor relays at the station to properly set the coordination of the relays. Feeders that meet the criteria for more than one recloser on the feeder, fibre optic communication provisions may be required for coordination and proper operation. Without fibre optic infrastructure connected from the station breaker to the recloser, the feeder may be limited to a maximum of one recloser due to coordination limitations. Hence, the plan may include a two-phase approach of installing reclosers on poles and then adding fibre optic in a subsequent phase or vice versa depending on feeder, station coordination and existing infrastructure.

E7.1.6.2 Downtown Contingency

Unforeseen field conditions, equipment configurations and new standards and materials will impact the station-to-station switchgear ties program. These include, but are not limited to, the following:

- Running new ducts in downtown congested areas: Underground civil structures have been utilized and/or constructed over the last several years. Additional civil plant will likely need to be constructed in congested areas, which may create unanticipated project delays and cost escalation. In addition, recent experience has shown increased civil cost and project delays due to very high-water tables near the waterfront
- The new switchgear requires a swing option. Generally, station-to-station switchgear ties require new switchgears with appropriate configuration. If a new gear is not available at the time of the tie project, project delays will occur. Project plans should ideally be based on suitable existing switchgear. Alternatively, projects should be only planned where there is high confidence that the switchgear will be ready when required
- Furthermore, station-to-station switchgear tie projects are expected to require new cabling, jointing and termination standards. Changes to standards should be addressed as soon as requirements can be firmly established.

- Finally, the response strategy to manage moratoriums and obstacles includes; reschedule civil construction work to avoid moratorium time periods, and redirect duct bank routes to avoid areas under construction moratoriums.

E7.1.6.3 System Observability

Overhead and underground sensors provide real time data which requires consideration for communication infrastructure. Current market products that have been proven and utilised in other Canadian power utilities to date include the use of SIM cards for communications. Considerations for network connectivity and coverage must be tested in advance of installation. In a previous Toronto Hydro study of 32 power line monitors, they all became obsolete after telecommunication networks advanced from the 2G network to the 3G and 4G networks. This significantly reduces the asset's useful life and return on investment. Compatibility with Toronto Hydro's current SCADA and FLISR systems will be considered along with overhead and underground sensors such that they can adapt with changing communication networks or be independent of them entirely. Additionally, some overhead and underground sensors within the current market require their own independent power sources. Top current market products show that the majority require DC power or batteries that may require replacing or charging. Visibility of battery life and signal strength of sensors would be major considerations to mitigate operational risks. Furthermore, risk considerations of extreme weather and extreme high/low Toronto temperatures along with instrument calibration would be realistic risk factors for these measuring assets. To mitigate these risks, data from the manufacturers and other utilities would be considered during the Request for Proposal stage which is planned for in 2023.

Online Cable Monitors will require fibre communication infrastructure to attain live data. Coordination and planning will be required prior to the installation of Online Cable Monitors especially in locations that do not presently have fibre communications that have been identified as an optimum location for an Online Cable Monitor. To mitigate the risk of not having the Online Cable Monitors installed in the most optimum locations, planners and operational controllers will need to ensure that fibre communications is installed prior to the Online Cable Monitors. Part of the strategy is to consider installing Online Cable Monitors where fibre optic already exists and then expand to areas that are fibre optic feasible.

The current market for Transformer Monitors may require a separate software for access to the live data being acquired. Lack of integration with the FLISR system is a risk as it may hamper the operational benefits if there are separate systems. To mitigate this, product selection must include customised or retrofitted integration to experience the full benefits on operations.

Lastly, integration of new technology into the current Toronto Hydro system will require IT support and vendor support. Accessing real-time data during a power interruption will require fundamental integration into the current software systems to achieve optimum use of the data.

E7.2 Non-Wires Solutions Program

E7.2.1 Overview

Table 1: Program Summary

Total 2020-2024 Cost ($M): $2.2	**2025-2029 Cost ($M): $22.5**
Energy Storage Systems 2020-2024: $1.2	Energy Storage Systems: $ 22.5
Local Demand Response 2020-2024: $1.0	Flexibility Services: OPEX only
Segments: Flexibility Services, Energy Storage Systems	
Trigger Driver: Capacity	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Financial Performance, Public Policy Responsiveness	

Toronto Hydro has been actively exploring how Non-Wires Solutions (NWSs) can support conventional utility planning since 2015, primarily through the Local Demand Response (LDR) program (now included in the Flexibility Services segment), but also through the deployment of grid-supporting Energy Storage Systems (ESS). In previous years, these two programs have been managed separately; going forward, they will be brought together under one Non-Wires Solutions program.

NWSs refer to operating practices, activities or technologies that enable the utility to defer the need for specific distribution or transmission projects, at a lower total resource cost, by reliably reducing system constraints at times of maximum demand in specific grid areas. Typically, these NWSs leverage the use of Distributed Energy Resources (DERs), often in partnership with utility customers, or with other enabling third-parties.

The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand). This approach can help utilities meet system needs while avoiding overbuilding, ultimately reducing the risk of stranded or underutilized assets. Given the scale of investment that will be required to meet high-levels of electrification, NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth.

The NWS program at Toronto Hydro has two broad streams:

1) **Flexibility Services**
   Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. The most well-established flexibility service program at Toronto Hydro is LDR, which has been running since 2015. For the 2025-2029 period, Flexibility Services will be expanded beyond standard 4-hour Demand Response (DR) to include other services that can address a demonstrated grid-need, such as shorter duration DR where appropriate.
2) **Energy Storage Systems**
   Energy Storage Systems at Toronto Hydro are an innovative tool to complement traditional utility technologies in addressing distribution grid challenges. For the 2025-2029 period, Toronto Hydro will focus on developing a scalable, demand-driven, ESS strategy that is responsive to distribution system needs and supports the pathway to renewable integration and electrification

Toronto Hydro's NWS strategy for 2025-2029 reflects the last eight years of experience in both LDR and the energy storage space. The vision for the future is a product of experience and reflection, resulting from facing and overcoming numerous challenges. The program is unique in that in contains both capital expenditures (ESS equipment), as well as operating expenditures (capacity or energy payments for DR capacity). These expenditures are outlined below.

E7.2.1 Flexibility Services

E7.2.1.1 Background and Future Vision

Toronto Hydro's vision for flexibility services is built upon its strong foundation of successfully deploying NWSs. Toronto Hydro, a leader in developing NWSs, intends to continue to evolve the opportunities and benefits afforded by NWSs.

Local Demand Response Overview

The LDR program is Toronto Hydro's flagship NWSs initiative. The LDR program was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program is designed to help address short-to-medium term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively.

The LDR program is a big step forward in evolving conventional utility station planning to include the consideration of NWSs alongside traditional "poles and wires" investments. This approach enables the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address short-to-medium term capacity needs.

Utilities regularly utilize information and data to prioritize infrastructure investment based on where the system needs it the most. Demand Response strategies can provide utilities with increased flexibility when determining which projects should be undertaken, which ones can be deferred to a later date, and which ones can be avoided entirely, ensuring optimal allocation of limited capital funds. This results in a more efficient use of capital, and in some instances, leads to avoiding capital expenditure all-together.

Since launching LDR in the 2015-2019 rate period, Toronto Hydro has demonstrated the ability to procure and deploy contractual DR capacity to support the grid. This experience has helped develop and grow capabilities in utilizing NWSs.

During the 2015-2019 period, Toronto Hydro ran LDR at one station located in the downtown core: Cecil TS. At the time, the utility was forecasting that capacity constraints would materialize on two busses at Cecil TS in 2020. Toronto Hydro used LDR to reduce summer peak demand by about 8 MW, helping to avoid anticipated capital investment. The anticipated capital investment was initially deferred to the 2025-2026 period. However, these upgrades were avoided entirely, as the load profile at Cecil TS evolved over the 2020-2022 period, resulting in a much different outlook which no longer necessitated station expansion. This pilot project is an example of how a utility can leverage customer-owned DERs to gain planning flexibility when dealing with investment needs that carry a high degree of uncertainty.

The Cecil TS LDR Pilot at a glance:

- Successfully contracted 8 MW of DR, working with commercial and institutional customers
- Reduced summer peak demand by 8 MW in 2018 and 2019
- Resource mix included back-up behind-the-meter generation and customer load curtailment activities
- 5-6 events per year, delivered over a 4-hour period (2pm to 6pm)

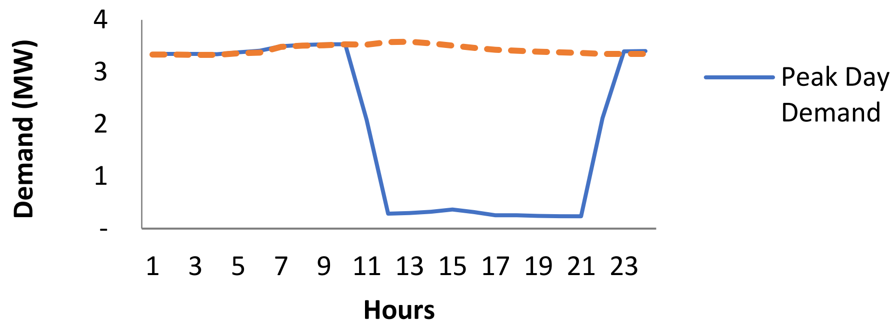


Figure 1. Sample LDR Event with a 3 MW Customer

For the 2020-2024 period, Toronto Hydro expanded the program to target two stations, Manby TS , and Horner TS. The details of this program are outlined in section E.7.2.2.4 below.

<u>Evolution of LDR: Flexibility Services</u>

For the next rate period, Toronto Hydro will build on the success of LDR to build a Flexibility Services program, which will expand to include services other than standard 4-hour DR. As with LDR, Flexibility Services are demand-side services that the utility purchases from customers and third-party vendors (i.e. energy services providers and aggregators) in order to address distribution system needs. These services allow the utility to work with customers and vendors to change where or when electricity is consumed, helping to level out peaks in demand. The goal is to find innovative ways to support electrification while enabling efficient use of capital, avoiding overbuilding the distribution system.

Table 2. Types of Flexibility Services:

Type of Service	Description	Use Case
Demand Response (DR)	Contractual arrangements with customers or aggregators for 4-hour blocks of load curtailment	Peak-shaving, capacity support
Short-Duration DR	Contractual arrangements with customers for 2-hour blocks of load curtailment. Enables participation from a wider variety of loads	Peak-shaving, capacity support

A key feature of the Flexibility Services program is the development of a competitive marketplace for the procurement of resources. To create this successfully, Toronto Hydro will:

- Identify areas in the system where demand-side approaches can help alleviate system constraints;
- Determine characteristics of capacity requirement (i.e. quantity, duration, seasonal need, expected number of activations);
- Conduct an options analysis to determine how these system needs can be addressed conventionally, and utilize this analysis to determine the capacity value and target price for capacity; and
- Communicate this information to prospective participants via an online platform; and
- Hold periodic auctions to procure capacity competitively, allowing Toronto Hydro to match available capacity with system needs.

One result of Toronto Hydro's 2020-2024 LDR program will be the creation of an online DR Capacity Auction tool, which enables the competitive procurement of DR capacity. This tool can be utilized in the 2025-2029 period to target several station areas (see Drivers section for more details). A prototype of the tool is currently under development in partnership with Toronto Metropolitan University's Centre for Urban Energy ("CUE").

E7.2.1.2 Outcomes and Measures

The Flexibility Services program works together with the Stations Expansion and Load Demand programs to ensure Toronto Hydro can supply growing customer demand while maintaining system reliability and improving grid resiliency. By leveraging customer-owned energy resources to offset peak demand, Flexibility Services provides incremental customer value in the form of grid optimization capabilities that were not traditionally available to grid planners and operators, while also providing an incremental source of value to current and prospective DER owners. This aligns with Toronto Hydro's broader modernization strategy, which aims to implement technologies and develop capabilities that will allow the utility to optimize the utilization and performance of its grid, ensuring distribution service and access remains as cost-effective as it can be while keeping up with anticipated demand pressures from electrification and the digitalization of the economy.

Table 3: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by:
	  ○ Engaging with customers and enabling them to participate in the grid
	  ○ Adding flexibility to the grid to enable efficient customer connections
	  ○ Providing revenue opportunities for DERs, thereby encouraging DER uptake and integration

Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system reliability objectives by providing additional tools for managing and prioritizing capacity constraints.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by acting as a bridging strategy to help to avoid (or defer) capital investments where demand is uncertain.

Public Policy Responsiveness	• Contribute to Toronto Hydro's public policy responsiveness objectives by:
	  ○ Responding to the regulator's direction for utilities to consider and leverage NWSs where possible to drive rate-payer value
	  ○ Reducing greenhouse gas (GHG) emissions by enabling the proliferation of energy storage, DERs, and grid-modernization
	  ○ Enabling electrification by investing in additional capacity and operational flexibility

E7.2.1.3 Drivers and Need

Table 4: Segment Drivers – Flexibility Services

Trigger Driver	Capacity
Secondary Driver(s)	Reliability

The Flexibility Services program primarily helps complement conventional station expansion and load demand programs to address capacity constraints on the distribution system. Pressures such as densification, population growth, and electrification create constraints that need to be addressed either by building additional capacity, transferring load, or reducing load on the system via demand-side services.

These conditions are expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[1] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D4 of the DSP). The Station Expansion program speaks extensively to the identified needs in Toronto Hydro's service territory over the 2025-2029 period.[2]

While the Station Expansion program at Toronto Hydro addresses large-scale, longer term load growth challenges through the provision of new or expanded transformer stations, the Load Demand program ensures that sufficient capacity is always available to keep pace with day-to-day load growth, preventing the overloading of system assets.

As described in the Load Demand program, a key tool for meeting capacity needs and ensuring system reliability and efficiency is bus level load transfers (load transfers between station buses to alleviate overloaded buses).[3] The Flexibility Services program directly supports Load Demand by identifying opportunities to defer or avoid these load transfers when and where it is appropriate.

To help identify where to target Flexibility Services, both long-term planning (station expansion) and short-term planning (load demand) needs are considered to identify opportunities for NWS support. Factors that are considered when selecting a target area include high-levels of projected growth, large customer connections (e.g. data centres), high levels of load connections generally, and projections for electrification drivers, e.g. electric vehicle adoption. For the 2025-2029 period, the Flexibility Services program will focus on one major station cluster in Toronto Hydro's service territory: Horseshoe North.

It should be noted that a key feature of the Flexibility Services program is that it can easily adapt in terms of scope and location to meet the most pressing system needs. The current focus on Horseshoe North is due to the high potential for NWSs to defer capital expenditure. This is based on the identified system needs, as well as an assessment of current and expected future DER capacity. This station cluster has emerged as an ideal target area because:

- High levels of load growth are expected over the next ten years;
- Large-scale developments (including City Downsview Development) are expected to materialize in the near-term;

[1] City of Toronto, *How Does the City Grow?* https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf
[2] Exhibit 2B, Section E7.4.
[3] Exhibit 2B, Section E5.3.

- Currently has a high-penetration of large Key Account customers, some of which have DER capacity that could be utilized to provide distribution grid services; and,
- It has been identified as an area that will require up to 130 MVA of load-transfers in the next rate-period.

Based on Toronto Hydro's most recent 10-year station load forecast,[4] three Horseshoe North West stations will require capacity relief in the 2024-2029 period: Fairbank TS, Finch TS, and Bathurst TS.[5] Details about the load projections in this area are outlined in the Station Expansion section and the Load Demand section.[6]

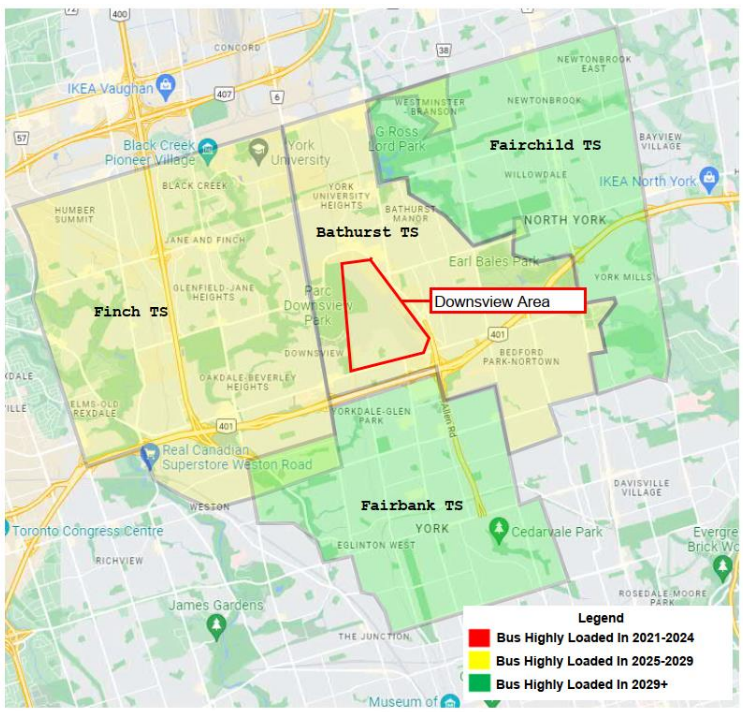


Figure 2: Service Territories of Stations in the Downsview Area

[4] Described in Exhibit 2B, Section D2.3 System Utilization
[5] Typically, load relief on a 27.6 kV horseshoe station bus is required when the forecasted peak load of the bus reaches 95 percent of the bus firm capacity.
[6] Exhibit 2B, Section E5.3.

Table 5: Non-Coincident Downsview Area 10-Yr Load Forecast[7]

STATION	Summer LTR (MW)	2021 Actual	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	71%	70%	75%	80%	85%	90%	94%	99%	98%	97%
Fairbank TS	182	108%	102%	92%	90%	90%	91%	90%	91%	91%	92%	93%
Fairchild TS	346	62%	68%	72%	72%	72%	72%	71%	71%	71%	71%	71%
Finch TS	366	69%	75%	88%	97%	97%	98%	98%	98%	99%	100%	100%
Area Non-Coincident %	**1255**	**72%**	**76%**	**79%**	**83%**	**84%**	**86%**	**87%**	**88%**	**90%**	**90%**	**90%**

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder.

Table 6. Load Transfers Anticipated in 2025-2029 Period

Station	Bus	Estimated Load to Transfer (MVA)	Area
Bathurst	*J&Q*	5 – 20	Horseshoe North
Fairbank	*B & Q*	15 – 30	Horseshoe North
Finch	*B&Y, J&Q*	25 - 55	Horseshoe North

Flexibility Services targeting these stations can provide temporary relief, giving planners flexibility to determine whether load transfers will become necessary. As part of the Load Demand program, station bus load forecasts are re-evaluated annually and informed by up-to-date system conditions,

[7] Hydro One Needs Assessment Report, Toronto Region (December,2022)

new connections, and updated weather corrected load forecasts. Based on the outcome of this evaluation, the need for specific load transfers can either be escalated in priority or deferred. This provides Toronto Hydro with the opportunity to explicitly consider and use NWSs to help avoid a portion of these load transfers when possible[8]. This consideration will inform where to focus NWS procurement efforts on an annual basis utilizing the appropriate, competitive process. This has been an auction process in the 2020-2024 period; however, as part of the ongoing evolution of this program, Toronto Hydro will continue to consult with stakeholders to refine and update the procurement mechanism, ensuring maximum participation from customers and aggregators.

Given the range of expected load transfers in Table 6, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help avoid anywhere between 28 percent to 66 percent of the total load required to be transferred in this area. This translates to avoided capital expenditure in the range of $10 million, at a projected cost of about $5.7 million in operating expenditure. Further details about costs are provided in the Expenditure plan.

E7.2.1.4 Expenditure Plan

Table 7 and Table 8 below summarize the LDR Program plan for 2020-2024.

Table 7: 2020-2024 CIR – LDR ($ Millions)

	2020	2021	2022	2023	2024	Total
CAPEX	1.0	-	-	-	-	1.0
OPEX	-	0.8	0.8	0.8	0.8	3.2

Table 8: Actual and Bridge Costs- LDR ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
CAPEX	1.0	-	-	-	-
OPEX	0.2	0.2	0.2	0.7	0.7

[8] As noted in the Load Demand narrative (Exhibit 2B, Section E5.3.), Manby TS and Horner TS, which were originally planned for relief in the 2020-2024 period, have been deferred to the 2025 period, in part due to the Local Demand Response program.

For the 2020-2024 period, Toronto Hydro has moved the majority of the capital allocated to the LDR battery system into the ESS program to plan and track all ESS projects under one program. The remainder of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized (i.e. OPEX). The majority of the costs are related to DR capacity payments ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration, legal costs, and consulting costs. Details about costs are provided in the program description below.

1. 2020-2024 Local Demand Response Program

For the 2022-2024 period, Toronto Hydro has continued to advanced capabilities in the NWS space, building on the work done in the 2015-2019 period at Cecil TS. For this period, the LDR program targeted two transformer stations (TS): Manby TS and Horner TS. These stations were selected based on specific needs; Manby TS has been reaching capacity on two busses for several years and overloading at Horner TS has been forecasted in the near-to-mid term. These capacity issues were identified in Toronto Hydro's 2015-19 Custom IR Application[9] and Hydro One's 2016 Regional Infrastructure Plan for the Metro Toronto Region.[10]

Several load transfers north to the Richview TS have been completed. Further transfers are difficult due to the distance between the stations and a lack of remaining overhead corridors running north-south. Load transfers to neighbouring stations to the east cannot be easily achieved due to capacity constraints at Runnymede TS, the Humber River posing a geographical barrier, and different system voltages (13.8 kV vs 27.6 kV). Load transfers to the west and south are not possible because the Manby TS and Horner TS are on the boundary of Toronto Hydro's service territory. Due to limited space at Manby TS for expansion, work has been underway to expand capacity at Horner TS. This new capacity will be utilized to relieve Manby TS in 2025. In the meantime, while the expansion work is undertaken, LDR has been leveraged to provide increased flexibility in the Manby TS and Horner TS area. As a result, some additional load transfers from Manby and Horner TS have been avoided over this rate-period and it is expected that this will continue to be the case until 2025, when load will be permanently removed from Manby TS to Horner TS.[11]

[9] Toronto Hydro Custom IR Application for 2015-2019 (OEB File No. EB-2014-0116).
https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2014-0116&sortBy=recRegisteredOn-&pageSize=400
[10] https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
[11] Exhibit 2B, Section E5.3

As noted, the majority of the LDR program costs are related to capacity payments for demand response ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration.

The capacity payments made to DR providers are benchmarked against the cost of additional load transfers that would have otherwise been required at Manby TS and Horner TS. It was estimated that the capital cost of executing 10 MW of load transfers from Manby TS or Horner TS to adjacent stations would be in the range of $4 million. Utilizing LDR to avoid these load transfers between 2023-2025 has effectively helped manage demand in this area until the expansion of Horner TS is complete and a permanent transfer can be made from Manby TS in 2025. As such, it was important to ensure that the total cost of LDR (capacity payments + admin) was well below the cost of the wires solution on a net present value basis. The maximum capacity payment for LDR was benchmarked utilizing a discounted cash flow model comparing the cost of load transfers to the cost of LDR, and the capacity payment was further driven down as a result of competitive procurements. The LDR program was initially projected to cost $4 million but will cost closer to $2 million over the current rate-period.

Evolution of LDR: Grid Innovation Fund Pilot Project

In late 2021, Toronto Hydro identified an opportunity to build on the LDR program planned for Manby TS and Horner TS to examine how Toronto Hydro and other distributors can work with the Independent Electricity System Operator (IESO) to better coordinate the use of DERs as NWSs in order to maximize value and lower resource acquisition costs. The IESO's regional planning documents indicated that capacity constraints were expected in the Richview-Manby transmission corridor starting in 2021. Transmission system upgrades will be necessary to address these capacity constraints. Due to project lead-time, the upgrades are not expected to come into service until 2025. The IESO is pursuing short-term measures, such as incremental Conservation and Demand-side Management (CDM) and DR, where feasible and cost-effective, to assist in reducing customer reliability risk until the transmission system upgrade can come into service.

Given the clear alignment of needs between Toronto Hydro and the IESO, Toronto Hydro partnered with Power Advisory LLC and Toronto Metropolitan University's CUE, to create a project that explores how to effectively and efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs. This project is called the Benefit Stacking

Transmission and Distribution Pilot (“Benefit Stacking Pilot”) and is supported by the IESO’s Grid Innovation Fund, and the Ontario Energy Board’s (OEB’s) Innovation Sandbox.

Currently, customers with load control capabilities or behind-the-meter DERs seeking to provide DR services interact with Toronto Hydro’s distribution system (e.g., LDR) and the IESO-operated transmission/bulk system (e.g. as Market Participant) separately. There is limited opportunity for coordination between the two systems to maximize the benefit and value of the DERs.

The Benefit Stacking Pilot Project explores how customer-owned DERs can provide services to both the distribution grid and transmission/bulk system using an efficient single pathway that works with existing market mechanisms. By making it easier for DER owners to participate in multiple programs thereby maximizing the value proposition for DERs to provide non-wires services, it is anticipated that participation levels would increase which would then, over time, drive down resource procurement costs. A key deliverable of the Benefit Stacking Pilot Project will be an analysis of the resulting rate-payer value of the dual DER participation.

Toronto Hydro will simulate offering LDR capacity into the IESO market, unlocking additional revenue streams and system benefits, often referred to as “benefit stacking”. Toronto Hydro will also simulate the utilization of the LDR resources in the IESO’s real-time markets, testing how Transmission-Distribution system coordination can be undertaken to avoid conflicting dispatch instructions between the two levels. The costs of the simulation are being funded through the IESO’s Grid Innovation Fun (GIF). The pilot explores current barriers to LDC-IESO coordination, seeks to improve overall visibility for both LDCs and the IESO with respect to DR resource activities and identify pathways for better coordination, leading to more efficient dispatch at both levels.

2. 2025-2029 Forecast Expenditures

Given the range of expected load transfers in Table 6, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. This translates to an avoided (or deferred) capital expenditure in the range of $10 million (at minimum), at a projected cost of about $5.7 million in operating expenditure.

Because Flexibility Services are market-based, the goal will be to again run competitive procurements that enable Toronto Hydro to drive down the cost of contracting for DR. The anticipated spend of $5.7 million dollars is based on the current market value of demand response in the LDR program, which is $700/MW-day for the summer 2023 period. However, each time a procurement is planned, Toronto Hydro will go to market to determine if the NWS is cost-effective as compared to the wires solution. To determine the cost-effectiveness, the cost of the specific load transfers would be compared to the procurement of DR over a specified period of time. This analysis determines the reference price for the DR, and the competitive procurement seeks to further lower this price through competition.

Table 9. Segment Unit Scenarios over 2025-2029 period

Segment	Cost per unit	Target Capacity	Projected cost	Capital Avoidance & Deferral
Flexibility services	$0.7M/MW	Up to 30 MW	$5.7M	$10M

Table 10: 2025-2029 CIR – Flexibility Services ($ Millions)

	2025	2026	2027	2028	2029	Total
Flexibility Services (OPEX)	0.2	0.9	1.1	1.6	1.9	5.7

It is anticipated that Toronto Hydro will spend the first year of the 2025-2029 rate period prioritizing targeted stations, setting capacity targets, and developing procurement processes and documentation. Between 2026-2029, Toronto Hydro will set the following procurement targets:

- 2026: 10 MW
- 2027: 15 MW
- 2028: 25 MW
- 2029: 30 MW

Program operating costs are based on an assumed capacity payment of $700/MW-day plus $200,000 per year for labour and operations. It is highly likely that the $700/MW-day figure will be driven down through competitive procurements over time, which means the total program cost for Flexibility Services should be understood as a maximum cost that could be significantly lower. The 2020-2024 total program cost, for example, will come in at almost half of what was anticipated due to procurement efficiencies.

E7.2.1.5 Options Analysis

Option 1: Conventional Wires Options

As noted, the wires option for addressing short to medium term constraints in the Horseshoe North cluster of stations would include bus level load transfers. The range of expected load transfers are indicated in Table 6 above. Proceeding with Option 1 would mean failing to consider the role of NWSs when scoping and prioritizing those bus-level load transfers, losing the opportunity to defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. Financially, this translates to a potential deferral or avoidance of up to $10 million in capital in the Load Demand program.

Additionally, proceeding without a Flexibility Services program would present a lost opportunity to build a more intelligent and interactive grid that can leverage local sources of generation and capacity resources to optimize grid performance. Doing nothing in the NWS space also presents a missed opportunity to work with customers and third-parties such as aggregators to find innovative solutions to distribution system problems. Customer engagement results indicate that it is important to customers to find ways to engage with the utility to better manage electricity usage, as well as to find efficiencies and cost reductions. The Flexibility Services program is directly responsive to this priority. Ultimately, the goal is to find the lowest-cost solution by exploring all possible options, including demand-side measures.

As demand becomes increasingly unpredictable due to increased uptake of DERs, Flexibility Services can help the utility navigate this uncertainty by providing a greater number of cost-effective options. This strategy checks an important regulatory requirement to evaluate alternatives to building traditional poles and wires infrastructure. It also enables a new lens on productivity – one that is focused on managing total system cost by optimizing how capital is allocated to address system needs more efficiently. In the Conservation and Demand-Side Management Guidelines, the OEB directs all utilities to explore NWSs alongside conventional wires solutions to provide cost-effective system options. Not proceeding with the Flexibility Services program would impact Toronto Hydro's ability to explicitly consider LDR options when addressing system issues.

Option 2: Continue with a small-scale LDR program that targets 1-2 stations

This option entails continuing with the LDR program as it is currently run in the 2020-2024 period, which means focusing on a modest capacity procurement of 10 MW and selecting 1-2 stations within the Horseshoe North cluster to target. This option would help defer a small number of load transfers in this area, and would come in at a lowered cost of about $3.6 million (about $2 million less than the proposed plan in Option 3). There are several drawbacks to this approach. While it does cost less, it also provides a reduced opportunity for load transfer deferral (about $4 million versus the $10 million in the proposed option). Furthermore, in the current LDR program, the feedback from aggregators has been that smaller target areas make it very challenging and costly to acquire enough capacity to make participation in LDR economical from their perspective. Targeting 1-2 stations can mean a relatively small pool of possible participants, leading to more difficult procurement processes. From a program administration perspective, it does not cost significantly more to procurement 30 MW versus 10 MW, making a larger-scale program more cost-effective overall. Looking at the number of DERs connected in the Horseshoe North area, targeted a greater number of stations results in a larger opportunity to contract for flexibility services.

Option 3 (Selected Option): Create a Flexibility Services Program that Targets Horseshoe North Station Cluster

Option 3, which is the recommended option, is to build a Flexibility Services program that works in tandem with the Load Demand program to address short-to-medium term load constraints in the Horseshoe North region of Toronto Hydro's service territory. This program will enable the explicit consideration of NWSs when evaluating and prioritizing bus level load transfers to address load growth and capacity issues in this area.

Because Flexibility Services are market-based, they also provide a crucial opportunity for utilities to leverage relationships with customers and third-parties to solve grid problems. Utilities have a great deal of system knowledge, data, engineering and operational experience; private sector organizations have developed excellent tools to help customers manage load behind the meter. Through working together, new and innovative ideas and solutions are generated that can help the sector better prepare for challenges ahead.

E7.2.1.6 Execution Risks and Mitigation

Procurement of Flexibility Services requires careful consideration of several factors. Over the last 8 years of running LDR, Toronto Hydro has navigated many challenges and come away with important lessons learned for how to manage risks.

Risk: Low participation levels in procurements

Going to market to procure flexibility services may not always yield successful results. This can be related to lack of resources, misaligned incentives, customer/participant confusion, or poor timing. To help mitigate these risks the following measures can be taken:

- Targeting station areas with a large penetration of large customers and existing DERs;
- Ensuring customers and aggregators are educated about programs through early participant engagement via program materials, webinars and one-on-one conversations;
- Creating programs that are straight-forward, with simple participation pathways and performance charges that create the right incentives without being too punitive; and,
- Ensuring aggregators have sufficient time to recruit customers.

Risk: Price discovery

One of the biggest challenges in the procurement of NWSs is price discovery. It is a given that the reference price for an NWS must be benchmarked against the cost of the wires alternative. However, the benchmark price may not always reflect the market price (i.e. the price the market participant is willing to take for their services). This process of price discovery presents many opportunities for learning and adapting in order to find the right balance of incentives. This includes not only the capacity or energy payment, but also any performance charges that may apply to ensure the services are reliably delivered. Some of the risks involved could include:

- Overpaying for services
- Setting prices too low resulting in low uptake
- Creating performance charges that are too lenient, resulting in poor performance
- Creating performance charges that are too stringent, resulting in poor uptake

To help manage these risks, it is important to learn from other jurisdictions, work with stakeholders in advance to understand their costs, and remain nimble and adaptable by doing shorter term procurements while working to understand the market. The experience gained in the 2020-2024 period has been instrumental in learning what works and what does not work in terms of price discovery. These learnings will be taken into the next rate period.

E7.2.2 Energy Storage Systems (ESS)

E7.2.2.1 Background

Energy Storage Systems give utilities the flexibility to store energy and use it at a later time. As demand for system flexibility increases and battery technology costs decrease, ESS are expected to play a growing role in generation, transmission and distribution system planning. Utilities can utilize ESS in a variety of ways to support the grid. Toronto Hydro has been active in the energy storage space since 2017, with several existing projects, including behind-the-meter ("BTM") and front-of-the-meter ("FTM") installations outlined in Table 11 below.

Table 11. Existing Toronto Hydro ESS Projects

<table>
<tr><th>Project</th><th>Description/Use Case</th><th>Nameplate Capacity</th><th>Learnings</th></tr>
<tr><td>Bulwer BESS</td><td>FTM BESS supporting Cecil TS via peak-shaving</td><td>2MW/ 2MWh</td><td>○ BESS deployment and optimization utilizing Toronto Hydro's Energy Centre (DERMS) platform
○ Trouble-shooting operational challenges (e.g. faults)
○ Experience with creating baselines and measuring peak-shaving success on feeder</td></tr>
<tr><td>500 Commissioners</td><td>BTM BESS located at Toronto Hydro's facility, used for peak-shaving and GHG reductions</td><td>500kW/ 500kWh</td><td>○ Optimizing use of BESS to lower facility electricity costs and target GHG reductions via peak-shaving
○ Experience with maintaining BESS</td></tr>
<tr><td>TTC eBus</td><td>Customer-specific project providing charging support and peak-shaving</td><td>1MW/ 4MWh x 3</td><td rowspan="2">○ Understanding of connection requirements from other stakeholders, such as HONI and IESO, for large size BESS deployments
○ Optimizing BESS operation for EV charging use case
○ Understanding of design and commissioning requirements of features such as black start and dynamic transfer which are needed for islanding scenarios</td></tr>
<tr><td>Metrolinx Eglinton Crosstown LRT</td><td>Customer-specific project used for emergency back-up and load displacement</td><td>10MW/ 30 MWh</td></tr>
</table>

Toronto Hydro has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, which is the only FTM

BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis,
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure,
- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level, and
- Maintenance of BESS assets.

Toronto Hydro also has experience with BTM BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (Metrolinx ECLRT and TTC eBus). These projects have also enabled building significant capabilities building, integrating and deployment of BESS. Based on current system needs, Toronto Hydro does not expect to own and install any BTM or customer-specific BESS projects in the next rate-period.[12]

<u>2025-2029 ESS Vision</u>

Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections.

The BESS program has matured significantly as a result of the last six years of experience. Due to the new and innovative nature of this program area, the work achieved up until this point has been primarily pilot driven. Toronto Hydro has tried various approaches for procuring and siting BESS. One of the main challenges has been finding locations to install projects in areas where the grid has specific needs that could be addressed by BESS. Given the urban and dense nature of Toronto Hydro's service territory, land comes at a premium, and the use of this land must be assessed carefully to

[12] See for example: OEB Staff Bulletin, August 6, 2020 re Ownership and operation of behind-the-meter energy storage assets for remediating reliability of service. https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-ownership-of-BTM-storage-20200806.pdf

ensure asset siting decisions are prudent and cost-effective. Another challenge has been to integrate different types of BESS projects, each with unique software platforms and maintenance needs.

The strategy for the next rate period will explore a standardized approach for siting, designing and procuring BESS, utilizing small scale installations that enable siting on the right-of-way, similar to other distribution system equipment (e.g. pad-mounted transformers). This, in addition to standard BESS deployments, will help Toronto Hydro build a more scalable and streamlined BESS program in the future.

Based on current, identified distribution system needs that will be examined below, as well as Toronto Hydro's commitment to support the electrification and anticipated growth of renewable generation in the city, the BESS portfolio will focus primarily on the renewable enablement use case in the 2025-2029 rate period. Several studies have shown that significant penetration of renewable generation can lead to destabilizing grid parameters.[13] In the renewable enablement use case, ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio (MLGR).

Based on internal studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. pad mounted transformers) that can accommodate the nameplate capacity, footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

Toronto Hydro is also actively working to optimize the deployment of BESS projects by leveraging its corporate-academic partnership with the Toronto Metropolitan University CUE. With this partnership, Toronto Hydro and CUE are developing an Optimal Planning Program which optimizes sizing and the return on investment of an ESS for both BTM and FTM applications. This tool will be an essential method in which Toronto Hydro evaluates and deploys BESS projects in the future for applications such as load displacement, deferred system expansion and premium reliability service. Quantifying net benefits for each of these scenarios will allow Toronto Hydro to design storage systems that can maximize the value proposition to the customer and the utility.

[13] Seguin, R., Woyak, J., Costyk, D., Hambrick, J., & Mather, B. (2016). (tech.). High-Penetration PV Integration Handbook for Distribution Engineers (pp. 4–26). Oak Ridge, Tennessee: Office of Scientific and Technical Information.

Another part of the BESS strategy is to improve asset integration so that newly deployed systems can co-exist with Toronto Hydro's IT framework. This will involve continuing to integrate all existing storage platforms within the Distribution Grid Operations Energy Centre DERMS platform.

E7.2.2.2 Outcomes and Measures

Table 12: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.
Operational Effectiveness - Reliability	• Contributes to service reliability by utilizing BESS technology to improve load-balancing on feeders that have been identified to have issues with respect to MLGR.
Financial Performance	• Contributes to Toronto Hydro's financial objectives and performance by cost-effectively enabling renewable generation where applicable.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by enabling the proliferation of energy storage, renewable DERs, and grid-modernization.

E7.2.2.3 Drivers and Need

Table 13: Segment Driver

Trigger Drivers	Capacity
Secondary Driver	Reliability, Public Policy

<u>Renewable Enabling BESS</u>

Policy, economic conditions and the preferences of customers and consumers, have facilitated a growing interest in DERs within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future supported by a number of drivers that are stemming from global, national and local levels such as the Federal Government's green energy tax credit and the recent Regulatory policy changes. In 2022, the Ontario Energy Board enacted changes that enabled third-party ownership of Net Metered generation facilities. Toronto Hydro anticipates that third-party installations will play a key role in driving renewable energy generation ("REG") growth during the next rate period as it did in other provinces and the US where this arrangement is already well established. In addition, the anticipated decreasing costs of photovoltaic panels is expected to have a positive impact on customer interest in REG. These drivers will increase interest in distributed renewable generation projects within Toronto Hydro's service territory by 2029, as shown below on Figure 3. Please refer to the Generation Connections narrative for more details on the drivers behind the anticipated REG growth in the next rate period.

An increase in renewable generation projects will lead to a fundamental change in the power flow conditions at the distribution system and how they need to be managed. This has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG is known to cause issues in distribution system planning and operations such as unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively relieve certain grid constraints on feeders in order to accommodate future REG growth.

As part of its DER connection process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, certain parts of the distribution system are approaching their technical limits and the problem could worsen over the next few years. Renewable Enabling ESS investments can help Toronto Hydro alleviate these issues to accommodate future REG growth, while maintaining adherence to the Transmission Interconnection Requirements.

As can be seen in the Figure 3 below, there has been a consistent increase in the number of renewable generation connections to the distribution grid. The data observed assumes a negligible uptake of wind or other inverter-based DER technologies and therefore uses the solar PV forecast as the primary REG type driving increased penetration. These assumptions are based on historical consumer behaviour in REG adoption in the City of Toronto and are consistent with forecasting models used in the Generation Connections segment.

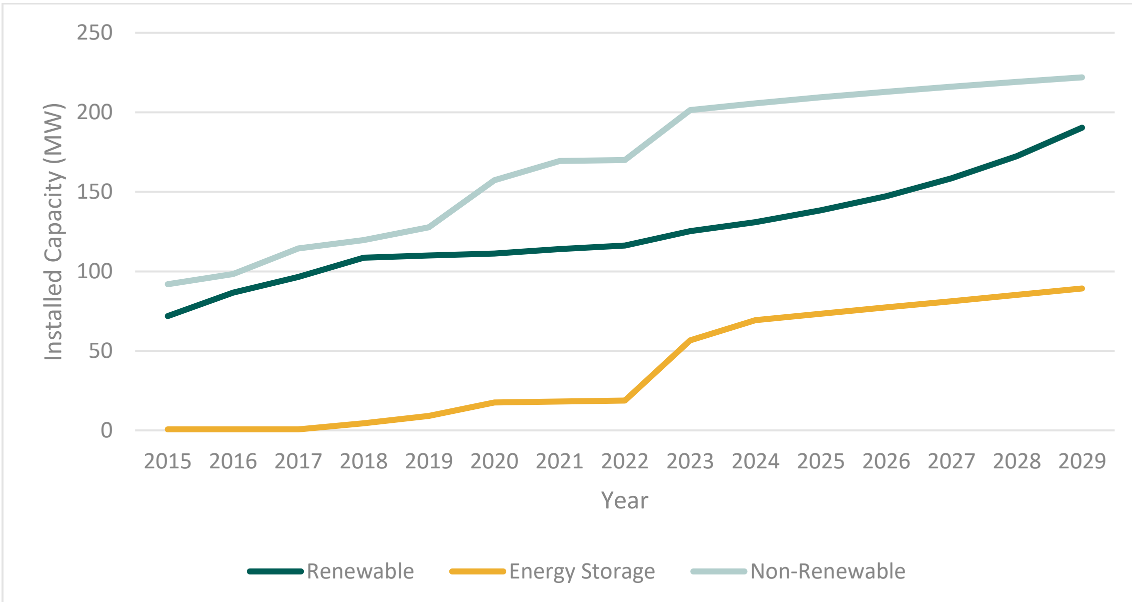


Figure 3: Historical and Forecasted Renewable Generation (MW)

Table 14: Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

High penetration of renewable energy generation sources can lead to grid instability if not managed appropriately. Two modes of grid instability can be seen: unintentional islanding and system overvoltage. While these issues can not be resolved easily using conventional utility approaches, ESS solutions present an ideal alternative given their ability to dynamically charge and discharge to balance feeder loading. The following sections will outline the two modes of grid instability and expand on how ESS can help alleviate the issues.

Unintentional Islanding

In the past few years, there have been numerous studies, standards and guidelines with respect to DER integration, such as IEEE Standard P1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)[14] and National Renewable Energy Laboratory's High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents prescribe limitations on DER aggregate capacity to be less than one-third of the minimum load of the Local Electric Power System. [15] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and this can adversely impact the effective inverter response to anti-islanding scenarios. This scenario can be mitigated with the addition of transfer trip protection, which is only a requirement for DER connections over 1MW; however, this is a costly measure. Furthermore, for feeders that have a high penetration of small to medium DER connections, it would not be economically feasible for each customer to install transfer trip as the cost is too high relative to the cost of the connection. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, renewable enabling ESS becomes an attractive option as it can serve to mitigate this risk for any customer along the feeder as opposed to being an individual customer solution.

Toronto Hydro conducted an analysis for all feeders in its system to establish minimum load to generation ratios[16] in accordance with the applicable guidance found in IEEE-P1547.2/D6.5, August 2023. The methodology consisted of aggregating the DER generation capacity at the feeder level. For this particular study only the DERs that were connected and in-service were used, and DERs that were proposed were only factored into the forecasted values. The next step involved using load profiles to determine the minimum load on each feeder in the past three years and computing the MLGR. This process was repeated for all feeders that had aggregate DER capacity above 500 kW. The list was further refined by calculating the REG penetration ratio on each feeder which helps identify feeders that would best be served by a renewable enabling ESS solution.

The DER forecast shown in Figure 3 above is a system level forecast that is consistent with the GPMC and Customer Connections narratives. This system level forecast was applied to the feeder level

[14] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, (11 Aug. 2023).
[15] Ibid.
[16] Determined as available utility fault current divided by DG fault contribution in affected area.

forecast in Table 15 below to determine the DER forecast for each of the shortlisted feeders as well as the forecasted impact on MLGR.

The study found that 23 feeders currently exceed the 3:1 minimum load to generation screening ratio outlined by the NREL Handbook and is shown in Table 15 below. Assuming there are no short circuit capacity constraints at the transformer station and given the forecasted growth in REG only by 2029, an additional 24 feeders would exceed the generation to minimum load ratio.

Table 15: MLGR feeder analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast 2029	REG Connections enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

Renewable Enabling ESS can be deployed on such feeders in order to increase the minimum load to generation ratio to the recommended threshold. The technology has the capability to do so by functioning like a load when the minimum load is low. Conversely, when the minimum load is appropriately above the threshold, the ESS can act like a generator by supplying energy. This can provide FTM load displacement as well as other target area specific benefits.

In short, the screening ratios show that by 2029 all 47 feeders will have a high penetration of PV generation and require grid investments or other solutions to ensure the safety of the grid and allow further REG connections. ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [17]

The direct benefit of installing renewable enabling ESS can be quantified by the amount of REG capacity that is enabled through these investments which is shown on the far-right column in Table 15 above. This also forms the basis for prioritizing which feeders should be resolved as they provide the largest benefits as a renewable enabling investment. Otherwise, a lack of these renewable enabling ESS investments would result in a forecasted amount of 30MW of REG by 2029 to be potentially rejected for connection.

Toronto Hydro also envisions renewable enabling ESS investments that are driven by large customers installing large renewable DERs. Such a large and sharp increase of renewable DER penetration could disturb the grid stability and the generation to load ratio. Renewable enabling ESS solutions would be installed on the relevant feeders to support the grid, smooth the ratio and allow for the increase of renewable generation on the grid.

System Overvoltage

ESS deployments can also mitigate the grid risk of experiencing overvoltage on some of Toronto Hydro's feeders. Load demand and PV generation have different impacts on a feeder's voltage profile. As load demand increases, operating voltage dips, while as PV generations increases, the voltage spikes. Based on internal studies, there is an increased overvoltage risk for equipment on feeders with low load demand and a high PV penetration. Results have shown that utilizing a BESS to balance the load on such feeders could mitigate that risk and consequently enable further renewable connections on the grid.

[17] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

E7.2.2.4 Expenditure Plan

1. 2020-2024 CIR Energy Storage Systems ("ESS") Program

Table 16: 2020-2024 CIR – ESS Program ($ Millions)

	2020	2021	2022	2023	2024	Total
GPESS	-	2.7	2.8	-	-	5.5
REBESS	1.0	1.0	1.0	1.0	1.0	5.0

Table 17: Actual and Bridge Costs – ESS Investments ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
BESS[18]	-	0.5	0.1	0.3	0.3

Toronto Hydro planned to install aggregate capacity of 8MW/4MWh of Grid Performance ESS over the 2020-2024 period, at a total cost $5.5 million. The plan was for the project to be implemented in 2021 and 2022. Toronto Hydro also proposed in the last rate application to install three Renewable Enabling ESS units with an aggregate capacity of 2.35MW/9.5MWh, at a total cost of $5 million.

Toronto Hydro faced numerous challenges in completing the proposed projects and was unable to proceed as planned. After exploring additional opportunities to deploy ESS, Toronto Hydro is proceeding with one renewable enabling ESS unit in the current rate period. This process has provided valuable information and experience that has informed the development of Toronto Hydro's ESS plan going forward. Toronto Hydro is revising its approach for this program in the 2025-2029 period, focusing on creating a more scalable, demand-driven ESS program that utilizes small-scale ESS technologies.

Toronto Hydro faced three significant challenges in deploying ESS in the 2020-2024 rate period:

i) Siting projects;
ii) Supply chain constraints; and
iii) Integration of one-off procurements into Toronto Hydro's IT and other systems.

[18] BESS amounts reflect combined investments for GPESS and REBESS.

Building on the lessons learned from navigating these challenges, Toronto Hydro has identified an opportunity to deploy an ESS unit to target a feeder that exceeds the MLGR threshold.

Challenges Deploying ESS

Siting ESS Projects

Finding a site has been the one of the biggest roadblocks for installing ESS in Toronto. It is often difficult to line-up a site in an area where ESS can provide cost-effective grid services. This challenge is uniquely difficult for Toronto Hydro as its service area is dense and urban. So far, Toronto Hydro has installed one front-of-the-meter ESS (Bulwer) at a decommissioned Municipal Station site.

Supply Chain Constraints

During the current rate period, COVID-19 led to significant supply chain issues resulting in major delays throughout the entire ESS sector. Certain types of equipment, such as Static Transfer Switches (STSs) had lead times of up to 2 years. Many of the after effects of these supply chain issues continue to impact project execution, specifically with respect to shortages in lithium production for Lithium Ion ESSs. Supply chain risks have diminished since the height of COVD-19 and are not expected to be material over the next rate period.

Integration of One-off Procurements

Another challenge relates to the integration of ESS into existing frameworks and systems. This is exacerbated by one-off procurements with several different vendors. For example, it has been a challenge to integrate various types of custom BESS systems that utilize different software platforms for system charging and management from an IT perspective. Toronto Hydro's IT systems have strict requirements with respect to data access, hardware and security. It is also necessary to create maintenance plans for the ongoing management of these assets, which can be made complicated when there are various types of custom system installed. To that end, Toronto Hydro is currently working on standardizing the process of ESS design and procurement through the development of technical requirements that will be used in future RFPs.

Grid Performance ESS (GPESS) Project

As part of the 2020-2024 period, Toronto Hydro explored the possibility of installing a 5 MW ESS to mitigate voltage sags on feeder 51-M30, which is fed by Leslie TS. This project was intended to pilot the use of an ESS to resolve voltage sag issues for large commercial customers located on the targeted feeder. This feeder was selected based on analysis evaluating the following criteria:

- Number of customers impacted:
  - More than one key account customer connected on the feeder
- Land for ESS installation:
  - Feeder must be in proximity to existing decommissioned Municipal Stations (MS) that can be utilized for ESS site
- High number of sags:
  - ION meter data for key account customers on select feeders exhibited high number of sags recorded for the 2018 to mid 2021 period
  - The number of interactions regarding voltage sag concerns between the customer and the Key Account team at Toronto Hydro were also considered a factor

Table 18: Targeted Feeder for GPESS Deployment

Candidate Feeder	Decommissioned MS Nearby?	# of Key Customers	2021 Recorded Sag Event	Recommended GPESS Size
51-M30	Yes (Lesmill MS)	2	Key Customer #1 - 32 Key Customer #2 - 29	5.2MW/1.3MWh

In 2020, Toronto Hydro hired Quasar to perform a study about the technical feasibility of an energy storage system that eliminates short duration voltage fluctuations on a feeder. The final report provided a high-level cost estimate for the feasible options, identified completed projects in which the solutions have been implemented and developed a list of vendors that offer the required equipment to implement suggested solutions.

In 2021, Toronto Hydro worked with GE to determine the feasibility of integrating a power conditioning system within the distribution system. The aim of the study was to identify the main possible topologies, determine load case scenarios, simulate the performance of the best selected topology and develop a preliminary sizing of required components.

In 2022, Toronto Hydro developed and ran a Request-for-Proposals (“RFP”) process to procure an ESS capable of providing voltage support on the identified feeder, as well as peak-shaving support, and the ability to island for the purpose of outage mitigation. This RFP was put out to market twice:

once in July 2022 and once in September 2022. Both processes resulted in no appropriate bids from vendors.

To understand the lack of response from vendors, Toronto Hydro conducted feedback sessions and learned that many BESS developers were focusing on larger-scale deployments (greater than 10 MW) that enabled ownership retention and power purchase agreements with the IESO (via medium and long-term contracts). Other vendors noted that the technical requirements of Toronto Hydro's RFP were complex and necessitated more in-depth preliminary engineering analysis to accurately define the requirements. With these lessons learned, Toronto Hydro is working with external consultants to undertake engineering studies assessing the technical feasibility of a BESS that addresses feeder-level voltage sags, while also determining the compatibility of this use case with others (e.g. peak-shaving, load-balancing, black-start). The goal is to be better equipped to scope BESS projects that enable benefit stacking, maximizing the cost-effectiveness of these projects.

Renewable Enablement ESS Project

Despite the previously-described difficulty in finding a viable site for REBESS, Toronto Hydro aims to target one small deployment within this rate period. The deployment being targeted this rate period will be on one of the 23 feeders which are above the MLGR threshold as highlighted in Table 15 above. The feeder selected for the deployment will hinge on the various constraints such as location, sizing and budget. The prudent approach would be to target a singular small deployment in an area that is relatively easy to deploy, gather learning lessons and carry those lessons into the planned deployments for the next rate period.

In addition to this, Toronto Hydro is working with internal stakeholders and vendors to explore innovative methods of deployment such as smaller scale BESS units along the right of way in order to alleviate the need to find large land areas as well as available decommissioned Municipal Stations that can be repurposed to site BESS.

2025- 2029 Forecast Expenditures

Table 19: 2025-2029 CIR – BESS ($ Millions)

	2025	2026	2027	2028	2029	Total
BESS	3.6	3.6	7.5	3.8	4	22.5

Table 20: 2025-2029 CIR – BESS (Systems)

	2025	2026	2027	2028	2029	Total
BESS	1	2	2	2	2	9

Toronto Hydro plans to deploy nine projects in the BESS program with an aggregate capacity of 10.2 MW to mitigate the forecasted impact of PV penetration and enable further renewable growth on the grid. The 10.2 MW of BESS capacity is what is needed to bring up the MLGR ratio on the 9 high-priority feeders outlined in Table 15, to the required MLGR threshold. The planned deployments are estimated to cost $22.5 million with an assumption of $446/kWh This works out to $1.78M/MW for a four hours system and results in an expenditure cost of $18.19 million. A 10 percent buffer was added for potential cost overruns resulting in a $20 million total expenditure cost. The derived $/MW is based on industry benchmark[19] as well as Toronto Hydro's renewable enabling ESS technology evaluation. Toronto Hydro plans to distribute the planned numbers of projects evenly over the next rate period to optimize utilization of current staff and take advantage of one project's lessons learned onto the next one.

Renewable enabling BESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. As with other renewable enabling improvements, renewable enabling BESS are funded six percent in Toronto Hydro's rate base and 94 percent through the provincial renewable enabling improvement revenue stream. Over the 2025-2029 period, $22.5 million is proposed for this segment, $1.6 million (six percent) allocated to Toronto Hydro's rate base as the assets are in-service. These investments are expected to enable the aggregate connection of 10.2 MW of REG by 2029, which wold otherwise not be possible due to the technical limitations of the grid.

[19] Viswanathan, Vilayanur, et al. "Energy Storage Cost and Performance Database." *Pacific Northwest National Laboratory*, 1 Aug. 2022, www.pnnl.gov/lithium-ion-battery-lfp-and-nmc.

Table 21: Priority REBESS Deployments

Station	Feeder Name	Existing DER Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast (2029)	REG connections enabled by 2029 (MW)	Req. BESS Size (MW)
Agincourt TS	63-M6	3.53	100.0%	5.77	7.10	2.011	1.230	2.24	3.49
Finch TS	55-M31	1.75	100.0%	2.95	3.52	2.011	1.193	1.20	1.73
Fairbank TS	35-M8	2.00	83.0%	2.80	5.50	2.753	1.750	1.15	0.49
Rexdale TS	R29-M1	1.12	100.0%	1.94	2.54	2.275	1.305	0.83	0.81
Horner TS	R30-M3	0.76	100.0%	1.38	1.91	2.519	1.387	0.62	0.37
Finch TS	55-M32	1.51	33.2%	0.97	4.09	2.712	2.069	0.47	0.43
Leslie TS	51-M25	1.68	25.5%	0.85	4.88	2.911	2.322	0.43	0.15
Finch TS	55-M29	1.91	21.7%	0.84	4.22	2.205	1.809	0.42	1.52
Fairchild TS	80-M10	1.30	23.1%	0.65	2.69	2.069	1.629	0.35	1.21
Total				**16.57**				**6.12**	**10.2**

E7.2.2.5 Options Analysis

1. Option 1: Do Nothing

Twenty-three feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and an additional 24 feeders are forecasted to exceed acceptable ratios by 2029. If no action is taken, it is possible that forecast demand for DG, including REG, would not be safely accommodated in those areas. This could potentially put forecasted REG connections with an aggregate capacity of 29.78MW at risk of getting rejected by 2029. This would be an undesirable outcome for customers, the City of Toronto, and Toronto Hydro and would hinder Toronto Hydro's ability to meet its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). This will also restrain the efforts being made to accelerate the uptake of renewables and meet net zero targets in Toronto. Customers who are willing to invest in modernizing the grid will likely become frustrated, and the associated grid and upstream benefits will not be realized. Finally, this will be in non-compliance with the results of Toronto Hydro's customer engagement process, which stressed on the importance of allocating expenditures to modernize the grid and support renewable growth.

2. Option 2: Traditional "poles and wires" solutions

While Toronto Hydro has the Generation Protection Monitoring & Control (GPMC) program to address system-wide issues to enable DER, issues involving generation to minimum load ratio, feeder phase imbalances and bus voltage imbalances will still persist and could potentially inhibit the connection of new renewable DER projects. GPMC will give Toronto Hydro the required control to disconnect DERs in case of an unintended islanding situation. However, the issues explained in section E7.2.2.4 cannot be addressed with the GPMC initiatives.

Feeder re-configurations and reverse load transfers could be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration. Furthermore, these are static solutions not well-suited to managing the dynamic nature of balancing load to generation, meaning these options would not resolve the issue the way a BESS would.

Another traditional option to mitigate the risk of unintentional islanding is with the addition of transfer trip protection; however, this is only a requirement for DER connections over 1MW and is a costly measure. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, it would not be feasible for customers to install transfer trip as the cost is too high relative to the cost of the connection.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring, and forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[20]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease.

[20] Exhibit 2B, Section E5.5.

In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

It is also important to note that for renewable enablement, curtailment is not an option as REG is either connected or not. While curtailment is not viewed as a viable option at the moment, Toronto Hydro is assessing the feasibility of having flexible DER connections on its system, which could work to mitigate load-to-generation imbalances for further DERs. More information about this program is outlined in the Grid Modernization Roadmap narrative.

4. Option 4 (Selected Option): Proposed Solution

The proposed Renewable Enabling BESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in Section 7.2.2.4 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Climate Action Plan with respect to enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 10.2 MW of REG by 2029 which would otherwise be constrained. The overall cost of this option is an estimated $20 million over the 2025 to 2029 period.

E7.2.3 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning. Compared to traditional technologies, there are fewer technical resources in the sector with knowledge on ESS that are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder or station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

Toronto Hydro will manage risks regarding integrating BESS with our current IT network through consciously working with the IT team to understand their technical requirements and considerations. This will help establish a standardized IT framework for the BESS program that we can incorporate in our upcoming project RFPs.

As outlined in earlier sections of this document, Toronto Hydro anticipates project siting to be one of the critical risks for this program in the next rate period. In order to manage this risk in the short term, Toronto Hydro is working with its Stations and Facilities teams to explore any available opportunity to repurpose existing Toronto Hydro facilities such as decommissioned Municipal Stations. At the same time, the end goal is to establish a more standardized and reliable approach for project siting. Toronto Hydro's vision is to create a strategy that leans on modular and small-scale BESS to enable BESS deployments on city boulevards, similar to other traditional Toronto Hydro assets.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts to ensure labour availability and manage project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on the 2022 Grid Energy Storage Technology Cost and Performance Assessment by Pacific Northwest National Laboratory,[21] battery ESS technology will mature and prices will fall, providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while inverters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Further, the report determined that current installed costs for Lithium Ion (LFP) BESS is $446/kWh and this is expected to decrease to $340/kWh by 2030. As such, over the 2025-2029 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[21] Viswanathan, Vilayanur, et al. "2022 Grid Energy Storage Cost and Performance Assessment." *Pacific Northwest National Laboratory*, Aug. 2022.

E7.3 Network Condition Monitoring and Control

E7.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 56.8	**2025-2029 Cost ($M)**: 6.0
Segments: Network Condition Monitoring and Control	
Trigger Driver: Reliability	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety, Financial Performance	

The Network Condition Monitoring and Control ("NCMC") program (the "Program") is introducing real-time, Supervisory Control and Data Acquisition ("SCADA")-enabled monitoring and control capabilities to Toronto Hydro's low voltage secondary network distribution system. The network system supplies 10-15 percent of the peak load in downtown Toronto, including customers like banks and hospitals who are highly sensitive to service interruptions. SCADA-enabled monitoring and control will benefit these customers, and the public who relies on these customers, by introducing remote monitoring and switching capabilities that are already utilized in many other parts of the system. It will also introduce real-time monitoring capabilities with respect to the following types of operating parameters:

- Air temperature and water level in the vault;
- Oil level, top-oil temperature and tank pressure of the network transformer;
- Current, voltage, open/closed status and presence of water level in the network protector, which is essential to the automatic transfer capabilities that allow the maximum reliability benefits of the network design to materialize; and
- Other sensors such as fire and analog water sensors for early detection of fire events and flooding.

These capabilities will enable improvement in key outcomes for downtown customers, the public, and the environment, including: remote identification of active failure risks (e.g. floods) and prevention of subsequent outages; the ability to sustain service for substantially more customers during multiple contingency events; early identification of potential safety risks (e.g. vault fires); early identification of oil leaks; and improved loading data accuracy, which will help Toronto Hydro provide greater and more efficient access to the network system for connecting customers. Finally, these capabilities will enable a reduction in yearly inspection activities, leading to maintenance cost savings once most of the network vaults are commissioned.

Toronto Hydro's progress in this program in 2020-2023 is a recent example of its grid modernization track record. For more information on how the NCMC program supports the Intelligent Grid component of the utility's Grid Modernization Roadmap, please refer to Exhibit 2B, Section D5.

The low voltage network distribution system has historically been Toronto Hydro's most reliable system. Over the last several years Toronto Hydro began deploying new, higher voltage network units to better accommodate new customer requirements in the downtown area and help reverse a gradual decline in the number of customers connected to the network. At the same time, the condition of the existing network is worsening as vaults experience floods and transformers corrode and leak oil, as evidenced by the many deficiencies observed in recent years. Catastrophic and highly disruptive failures affecting customers have also occurred in recent years. Given these constraints and pressures, Toronto Hydro is prioritizing the program as a means of improving reliability, system resiliency, and efficiency of operations on the network.

Toronto Hydro is investing $56.8 million in the 2020-2024 rate period and $6 million in the 2025-2029 rate period to install monitoring equipment and fibre optic cable in approximately 920 network vaults. Once this initial deployment is complete, Toronto Hydro plans to invest $1.8 million between 2026 and 2029 on a pilot project to further enhance real-time monitoring capabilities by installing additional sensors in the network vault. This will support the outcomes summarized above and described in more detail below.

1 ## E7.3.2 Outcomes and Measures

2 **Table 2: Outcomes and Measures Summary**

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives (e.g. OEB's ESQR targets, which require new services to be connected on time 90 percent of the time) by enabling more efficient connections through use of live loading data for power flow modeling.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives by: ○ Reducing flooding-related equipment damage; ○ Enabling the early detection of conditions that can cause vault fires to improve response time and mitigate damage; ○ Providing real-time loading data and remote switching capabilities to allow controllers to drop approximately one-third fewer customers from the network during multiple contingency events. • Contributes to network grid resilience by: ○ Identifying flooding so that measures can be taken to prevent equipment damage.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing oil leaks through monitoring of transformer oil levels.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives by enabling early warning of potential risks associated with vault loading, flooding and fire. • Remote monitoring will reduce time crews spend in the confined space of a vault to determine loading and protector status.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by reducing the need for crews to perform inspections needed to obtain summer load readings.

E7.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Failure Risk, System Efficiency, Resiliency

As summarized in Toronto Hydro's Grid Modernization Roadmap, the NCMC program is an important part of Toronto Hydro's Grid Modernization Roadmap and a recent example of its modernization track record. The NCMC program is successfully introducing the capabilities and benefits of an Intelligent Grid to Toronto Hydro's network system, including enhanced observability (i.e. real-time or near real-time data on grid performance and conditions) and incremental controllability. Together, these capabilities are providing a foundation for the realization of substantial reliability, resiliency and efficiency benefits.[1]

The Program aims to improve the reliability of Toronto Hydro's low voltage secondary network system by introducing real-time SCADA-enabled monitoring and control. The installed equipment and fibre optic communication cables provide live condition, loading data and remote-control capabilities in approximately 920 vaults that will enable Toronto Hydro to respond proactively and more effectively to emerging hazards and multiple-contingency events, leading to fewer and shorter interruptions for sensitive downtown customers. The planned number of vaults represents approximately 90 percent of the network vaults in the system. Toronto Hydro is not planning to target the remaining 10 percent due to the following factors:

- The equipment in the vault is manual and not automation ready, such as using manual secondary switches instead of network protectors; and
- The location of the vault requires high civil costs due to its remote location and lack of spare ducts required for fibre.

As the Program matures, Toronto Hydro is piloting other options to connect vaults without the need for fibre, such as using a long-term evolution ("LTE") communication device. Toronto Hydro is piloting this solution in a few vaults using customized Vault Communication Boxes ("VCBs"). If successful, this

[1] Exhibit 2B, Section D5

could allow Toronto Hydro to bring NCMC functionality and capabilities to vaults that would otherwise be cost-prohibitive.

Figure 1 depicts the components required to enable monitoring and control of a network vault and unit. Vault sensors – which include a water level sensor and a vault temperature sensor – are connected directly to the VCB. Transformer mounted sensors include oil temperature, oil level and tank pressure. Protector monitoring and control are all enabled through a special communication-ready network protector relay mounted inside the network protector.[2] Based on the age and make of the network units, some need to be retrofitted as they do not have the required sensors built-in (oil temperature, oil level and tank pressure). These retrofit packages will allow for NCMC capabilities to be available at the vault.

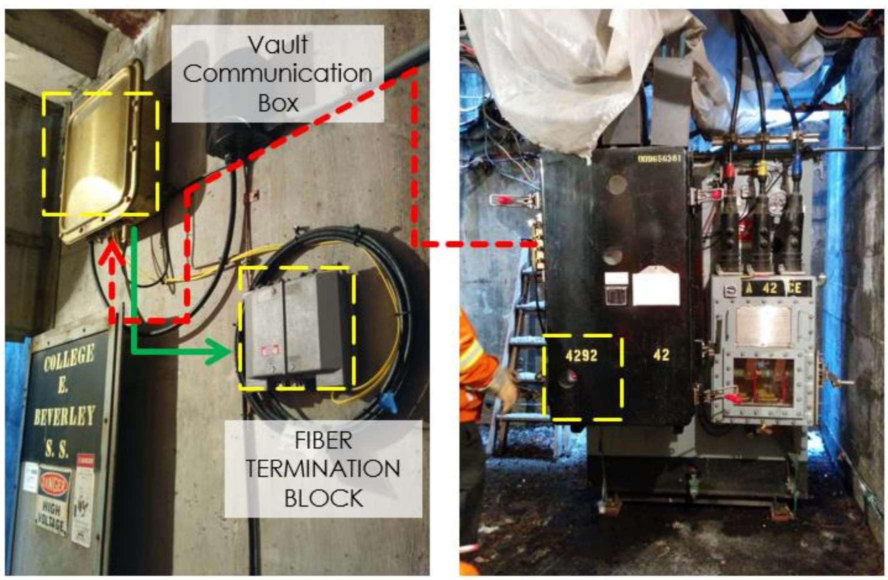


Figure 1: Vault Layout with Network Condition Monitoring and Control Equipment Installed

Once the VCB is installed, connected and commissioned inside the vault, Toronto Hydro can monitor and control the automated vaults through a SCADA screen from the control room, an example of which is shown in Figure 2 below.

[3] The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures.

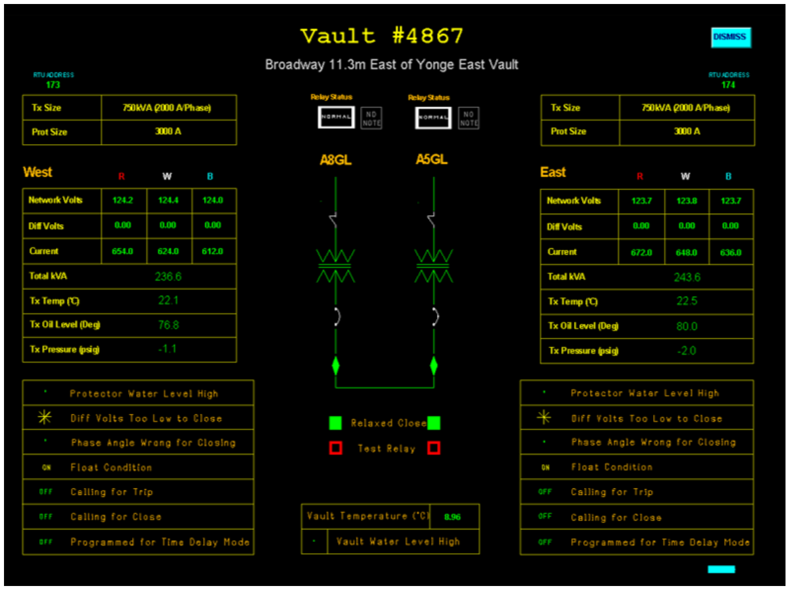


Figure 2: SCADA Screen for a Vault with Network Condition Monitoring and Control

E7.3.3.1 Benefits of Network Condition Monitoring

The Program will provide real-time condition data of the vault and network units. This will give the Control Room access to important information on developing hazardous conditions such as flooding, fire, and oil leaks, allowing proactive measures to be taken to prevent equipment failure and mitigate safety and environmental risks. Such data includes vault temperature and water level, network transformer operating temperature, oil level and tank pressure, and the presence of water inside network protectors. When real-time condition data is not available through NCMC, it is acquired through estimates or field inspections, which are both less accurate and more resource intensive.

The use of water level sensors can mitigate the risk of equipment damage and reduce customer service interruptions due to vault flooding. Once installed, water level sensors trigger alarms in the Control Room as rising water reaches the sensor. Toronto Hydro can then dispatch a crew to address the flooding prior to water levels reaching a point where equipment is damaged or at risk of failure. In the past two years, water alarms were raised at 56 network vaults which helped prevent flooding in the vault from occurring.

Monitoring of the network vault temperature will also enable Toronto Hydro to detect fires earlier, improving response time and mitigating any damage to equipment and safety risks that may result. If a fire occurs, the Control Room will be informed and can remotely operate vault equipment to prevent catastrophic failures. This would help lessen the impact to the customers directly connected to a given vault, as well as minimize potential widespread network outages that impact all customers connected to the network grid. In the past two years, temperature alarms from 14 unique vaults were triggered, allowing for pre-emptive response to potentially catastrophic failures.

Oil leaks are another concern which can be addressed through network monitoring. If a serious transformer oil leak is not promptly identified, the transformer is likely to fail once the oil level drops below the windings or upper cooling tubes. This could result in a catastrophic transformer fire causing widespread and prolonged customer interruptions and safety risks. In addition, early oil leak identification can minimize environmental damage. Leaking oil within a vault may enter the vault drainage system and discharge into the environment. Oil level monitoring data will also support the accurate reporting of oil quantities to the Ministry of the Environment and Climate Change and the City of Toronto should a spill occur.

This Program has already contributed to reducing the number of oil leaks and, more specifically, high-volume leaks as seen in Figure 3. In 2021 and 2022, SCADA event logs indicate there were 34 incident alarms of low oil level at 16 vaults which enabled early detection of oil leaks, limiting the volume of those leaks.

The majority of the oil leaks from 2020 onwards were within the 0-10 litre volume range. This timeframe aligns with the start of network vault commissioning with NCMC. A specific example of NCMC mitigating oil leaks occurred in June 2022, when a NCMC commissioned unit was leaking approximately 500 ml of oil per day. Once the alarm occurred, the controller trigged a crew to verify and open the primary switch to isolate the defective unit. The unit was subsequently reactively replaced. As Toronto Hydro continues to commission more vaults, the Control Room will be able to respond much earlier to any potential oil spill across the network system to minimize the number of spills as well as their volume.

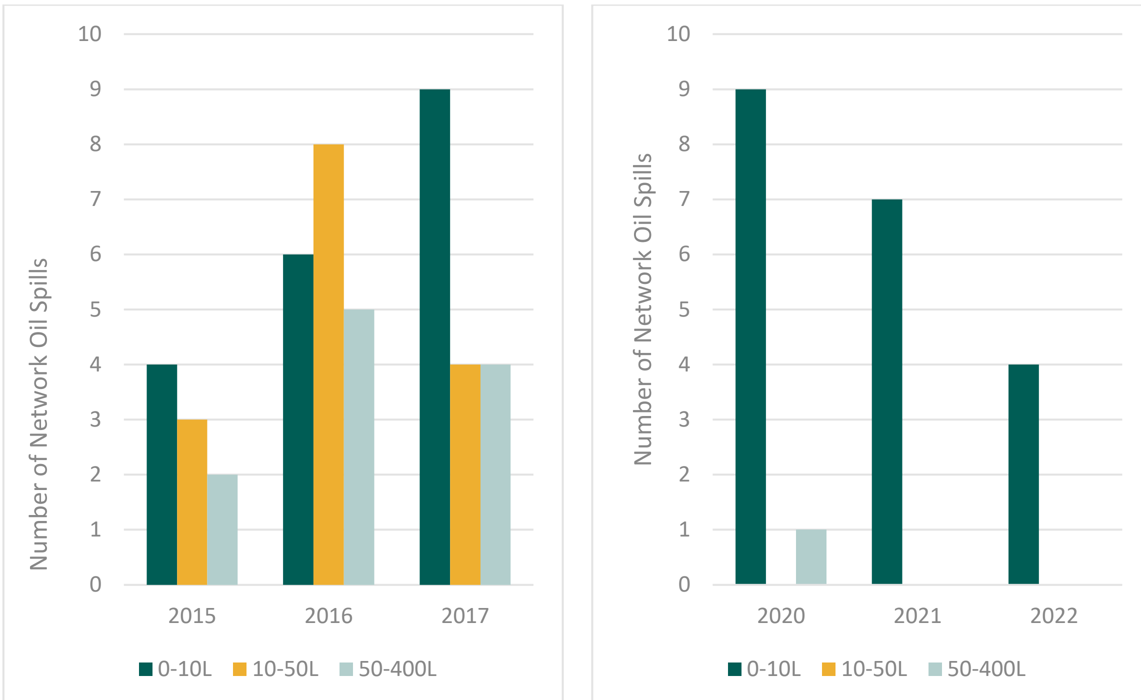


Figure 3: Network Transformer Oil Spills before NCMC (left) and after (right) NCMC

This Program will reduce the need for field staff to patrol networks, identify and investigate deficiencies such as protectors, flooded vaults (after heavy rainfall) and faulted network transformers. This results in estimated cost savings of $200 per hour per incident.[3] In the last five months of 2022, Toronto Hydro saved approximately $78,600 in operating costs by remotely checking protectors in commissioned vaults rather than sending trucks and crews. Toronto Hydro expects these benefits to scale as it continues to commission vaults.

Toronto Hydro has realized benefits from the condition monitoring achieved in the network vaults commissioned to date. As of the end of 2022, 379 vaults have been commissioned, which amounts to approximately one-third of all network vaults. As the Program continues to mature and more vaults are commissioned, Toronto Hydro is planning to continue to calibrate alarms and improve business processes in order to maximize the benefits of the Program.

[3] This is the cost of sending a crew to investigate an incident in a network vault.

E7.3.3.2 Benefits of Network Unit Control and Loading Data

Monitoring and control equipment also provides remote control capabilities and loading data required for emergency operations as well as normal analysis and planning. Real-time loading data allow controllers to more effectively respond to multiple-contingency events and emergency situations, resulting in fewer and shorter customer interruptions. Remote monitoring and control can also reduce the need for crews to visit vaults during switching events. For example, as of June 2023, Toronto Hydro has saved approximately $119,850 through the reduced need to deploy crews to vaults during switching events. This benefits customers by both expediting service restoration during network emergencies, as well as reducing costs associated with normal network system operations. Features that will provide these benefits include:

- Monitoring of operating voltages and currents;
- Monitoring of the open/closed status of network protectors;
- Ability to remotely open or close protectors;
- Automatic reporting of conditions preventing equipment from automatically operating as desired (e.g. voltage too low to reclose); and
- Ability to temporarily alter equipment settings to facilitate automatic operation (e.g. "relaxed close") that would otherwise not occur.

The loads for the low voltage secondary networks targeted for this program in 2020-2025 are shown in Table 4 below. Through this program, Toronto Hydro expects to avoid dropping one third of the total network load (which would otherwise have to be dropped in multiple contingency events). These networks are designed to handle first contingency (N-1) outages at both the feeder and network unit levels without causing customer interruptions. However, second contingency (N-2) or higher events require network analysis to determine whether customer loads can be sustained or must be dropped in order to avoid excessive equipment loading levels. In the absence of live loading data, conservative load estimates are made for this analysis. Toronto Hydro derives these estimates using loading data from summer inspections, which may not be accurate due to variances in season, ambient temperature, time of day, and day of the week. In contrast, accurate real-time loading information will allow the Control Room to operate network equipment according to the actual limits during multiple contingency events.

Table 4: Potential Customer Load Saved from Network Monitoring and Control[4]

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Commissioning Year	Expected Load Saved During Multiple Contingency Events (MVA)
Cecil-North Phase 1	32	6.5	2019	4.3
Cecil-South Phase 1		6.5	2020	
Windsor-West Phase 1	55	12.5	2020	8.3
Windsor-West Phase 2		12.5	2021	
Terauley-North Phase 1	44	13.5	2021	9
Terauley-North Phase 2		13.5	2021	
George and Duke Phase 1	49	11.6	2021	9.7
George and Duke Phase 2		17.4	2021	
Charles-West Phase 1	45	11	2022	7.3
Charles-West Phase 2		11	2022	
Bridgman Total	29.2	14.6	2023	4.9
High-level Total	112	56	2023	18.7
Glengrove Total	28	14	2024	4.7
Duplex Total	69.6	34.8	2024	11.6
Gerrard Total	12	6	2024	2.0
Dufferin Phase 1	21.2	4	2024	5.3

[4] Full benefits will be realized when the full network has been commissioned (automation).

Dufferin Phase 2		12	2024	
Wiltshire Total	1	1	2025	0.3
Leaside Total	3	2	2025	0.7
Main Total	9	7	2025	2.3
Carlaw Total	9	7	2025	2.3
Strachan Total	9	7	2025	2.3

In the last two years, real-time loading data from commissioned network units was used by controllers during multiple contingency events to determine accurate loading conditions and improve operating decisions:

- In January 2022, a fire in a cable chamber was caused by the network's secondary cables. Loading analysis was required to determine if a widespread outage on the Windsor network would be required. Controllers used real-time loading data as the input and determined that it was possible to support a multiple contingency event to isolate the affected area without resulting in a large outage on the network.
- In February 2022, a fault occurred on the Cecil network which supplies highly sensitive customers such as banks and hospitals. Using the NCMC real-time data allowed the crews to identify the fault and re-energize the network in an hour. In addition, NCMC capabilities allowed Toronto Hydro to confirm that the network was able to operate on second contingency and avoid taking the network down completely.
- In February 2023, a feeder on the George and Duke network experienced a cable fault and a neighbouring feeder tripped shortly after, causing the need for an N-2 assessment. The use of real-time loading data determined that the multiple contingency event could be supported on the network.

Real-time loading also helps support planned work in addition to failures. Historically, when real-time loading data was not available, Toronto Hydro could not schedule an outage on multiple feeders and vaults simultaneously for planned work, as the specific impact to the network would not be known or definitive. For example, in April 2022, the Cecil network was assessed and confirmed through loading data that multiple feeders and vaults could be taken out of service to support planned work. This allowed the planned work to be scheduled on time.

Table 4 also shows the potential customer load that may be saved for each network during a multiple contingency event. These are estimated based on the avoidance of dropping one third of the network load once the whole network has NCMC capabilities.

Continued deployment of the Program will provide highly accurate peak readings of Toronto Hydro's network assets than can be achieved through summer vault inspections. From a planning perspective, engineers will be able to model the various parts of the system with greater accuracy and plan based on more accurate power flow models. Network customer requests can be challenging to handle, and accurate power flow models are essential for efficiently connecting customers. More efficient connections will result in lower-cost and faster customer connections, contributing to Toronto Hydro's compliance with OEB-prescribed objective to connect new services on time 90 percent of the time.

Toronto Hydro inspects and maintains its network vaults and equipment through the Preventative and Predictive Underground Line Maintenance program.[5] As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027. At the end of the NCMC program (e.g. once all vaults are commissioned), this will result in approximately $275,000 in maintenance costs avoided each year.

E7.3.3.3 Enhanced Monitoring Capabilities Post 2025

Toronto Hydro expects to complete the original objectives of the program by the end of 2025, at which point the utility plans to initiate a pilot project to further enhance real-time monitoring capabilities by exploring different types of additional sensors that can be installed in network vaults:

- **Fire sensor**: This will allow earlier detection of fire events and allow timely intervention to limit equipment damage as compared to the vault temperature sensor.
- **Analog Water Level Sensor**: The analog sensors will provide additional data (i.e. measure of actual water level versus just the presence/absence of water) to remotely assess flooding severity as compared to the binary water level sensors thus reducing dispatches to assess vault condition. It would provide a means for the Control Room to prioritize reactive crew allocation.

[5] Please see Exhibit 4, Tab 2, Schedule 2 for more details.

- **Video Camera**: These can help detect unauthorized intrusion, and provide remote verification of alarm or unsafe conditions. This would allow the crews to better understand the situation of the vault prior to entering.
- **Vault Hatch Open Sensor**: Identify unauthorized intrusion and mitigate risk to the public (access to energized vault or a tripping/fall hazard).
- **Secondary Cable Monitoring with Cable Sensors and a Remote Node Collector**: Enhance the ability to extend operation of secondary networks under second contingency by identifying when secondary cables reach critical overload. Also, it will allow monitoring of the loading and condition of secondary cables emanating from network protectors and provide timely detection of the operations of cable limiters which could result in complete or partial outage to customers.

Overall, these enhancements will assist Toronto Hydro in further reducing safety and reliability risks, and in strengthening the resilience of the grid. This will also help save important utility assets before they fail or reach end of life earlier than they should. Lastly, by early detection of potential catastrophic situations, the utility will be able to prevent major incidents from occurring.

E7.3.4 Expenditure Plan

The program aims to improve issues related to reliability, safety, failure risk, and system efficiency primarily by investing in monitoring and control equipment installations inside network vaults, as well as a fibre optic communications backbone installed under city streets. Table 5 below depicts the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) spending for this program.

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Condition Monitoring and Control	8.1	12.5	13.0	11.0	12.2	4.2	0.2	0.4	0.6	0.6

The prioritization, scheduling and completion of projects in this program are based on the proposed fibre optic installation plan shown in Figure 4. Installation of the necessary fibre backbone is a prerequisite for testing and commissioning of monitoring and control equipment installed in individual vaults. Therefore, equipment installation in vaults is planned for the year following the completion of fibre installation. In addition, network units installed after 2010, including those to be replaced through the Network System Renewal program, will be equipped with the necessary relays and sensors required for monitoring and control. Network units that are retrofitted are also allocated within the budget under VCB installation.[6]

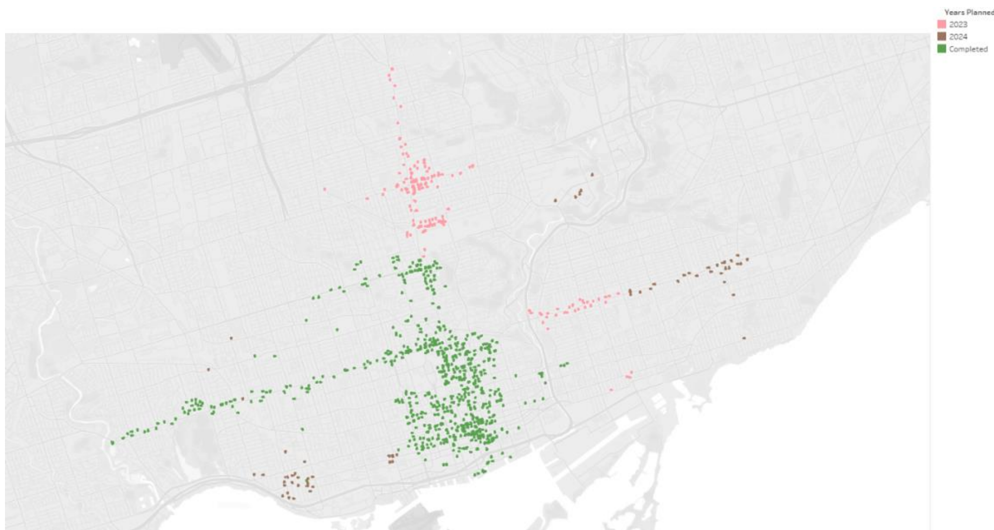


Figure 4: Fibre Optic Cable Deployment by Year

E7.3.4.1 2020-2024 Expenditures

Over the course of the Program so far, Toronto Hydro has commissioned 379 vaults, including 367 over 2020 to 2022. Toronto Hydro spent $33.6 million over 2020 to 2022 and plans to spend approximately $23.2 million and commission an additional 320 vaults over 2023 to 2024. Toronto Hydro no longer expects to complete the program by the end of 2024, as was originally proposed. As shown in Table 4, Toronto Hydro expects to complete commissioning of all except six of the networks proposed in the 2020-2024 DSP, four of which are the smallest networks by load.

The delays have been driven primarily by three factors. Firstly, fibre projects have been completed more slowly than expected due to execution challenges, such as resource constraints in 2020-2021, and additional time required to coordinate with external utilities to complete necessary civil work. Secondly, the work related to commissioning of the vaults started later than planned and the pacing

[6] Exhibit 2B, Section E6.4.

was also slower due to the learning curve from introducing new equipment, training requirements, and change management challenges. Thirdly, supply chain delays for VCBs caused work plans to slip and carry over into subsequent years. In 2022, the VCB supplier informed the utility of expected delays in acquiring the raw materials (brass sheets) required for manufacturing. To mitigate delays in program implementation, Toronto Hydro's engineers developed a new standard that allowed the VCB to be constructed from stainless steel. This innovation allowed Toronto Hydro to complete 129 of its planned 161 units before year-end as well as have a backup option to avoid any potential material delays. Remaining units have been scheduled and completed in Q1 2023.

It should be noted that while Toronto Hydro has been modernizing its system for many years, the NCMC program represents Toronto Hydro's first full-scale implementation of a new set of distributed grid technologies since the roll-out of the first generation of smart meters. While some challenges and delays have been encountered in this implementation, Toronto Hydro believes that the lessons learned, skills developed, and organizational capacity gained through this experience will support a successful and efficient implementation of the Grid Modernization Roadmap in the 2025-2029 rate period.

E7.3.4.2 2025-2029 Expenditure

Toronto Hydro plans to spend approximately $4.2 million in 2025 and commission the remaining 222 network vaults required to complete the original NCMC program plan. Any future renewal of the equipment installed through this Program and associated recommissioning work will be completed through the Network System Renewal program.

Over 2026 to 2029, Toronto Hydro plans to invest approximately $1.8 million to assess the viability of commissioning the remaining vaults not completed by 2025 as well as launch a pilot project that will install additional sensors, such as fire and analog water sensors, cameras, vault hatch open sensors and secondary cable monitoring, to further enhance monitoring capabilities in 35 network vaults (approximately 4 percent of network vaults). The network vaults targeted will be prioritized based on factors including, but not limited to history of flooding, higher voltage units, top entry vaults, and network grids where there is larger amount of secondary cabling. The investments in additional sensors will further improve real-time awareness in the network system, leading to improved decision making and pre-emptive response to different types of failures. These incremental investments will lead to substantial benefits as the investments already made in fibre and VCBs can be leveraged.

E7.3.5 Options Analysis

E7.3.5.1 Option 1: Sustainment

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025, installing and commissioning monitoring and control equipment installations inside a total of 920 network vaults and providing associated reliability, safety, and system efficiency benefits. Once this is complete, Toronto Hydro would not do any additional work to further enhance real-time monitoring capabilities by installing additional sensors.

This option would forego additional modernization on the network system and limit the value of the upfront investments made on the infrastructure to enable NCMC. Benefits from future developments and technology in network system modernization would be missed, including substantial reliability, resiliency and efficiency benefits, as described in more detail in Sections E7.3.3 and E7.3.4.2.

E7.3.5.2 Option 2: Improvement

Under this option, the same as under Option 1, Toronto Hydro will complete the original NCMC program plan in 2025. Once that is complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025. Once complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

E7.3.6 Execution Risks & Mitigation

E7.3.6.1 Fibre Installation

Fibre optic cable is the first asset that must be installed as part of the Program. Installation of fibre under city streets poses a number of risks that may cause program delays and increase costs, including:

- Lack of existing duct capacity for the fibre optic cable;
- Road construction moratoriums and road work restrictions;
- Construction blocking access to cable chambers and vaults; and
- Leaking cables posing hazards that prevent workers from entering cable chambers and vaults.

If a problem is only identified once construction begins, it results in reactive work, increased cost, and program delays. Toronto Hydro mitigates these risks by performing detailed field inspections during the design phase of the program and then designing solutions that avoid problem locations altogether. Alternatively, Toronto Hydro can plan ahead for necessary construction work to avoid impacting the program's critical path timeline. Toronto Hydro has piloted the use of wireless technology in NCMC applications by utilizing a long-term evolution ("LTE") communication device to connect to SCADA systems. If successful, this technology will provide an alternate way to add NCMC capabilities to network vaults by enabling remote connection where fibre optic communication cannot be deployed due to the risks mentioned above.

E7.3.6.2 Vault Equipment Installation

Certain risks can delay the installation of equipment inside network vaults and increase costs, including:

- Flooded vaults;
- Lack of suitable available space to install equipment;
- Existing primary feeder installation interfering with the installation of transformer sensors; and

- Legacy protectors not compatible with newer communicating relays required for NCMC.

Toronto Hydro mitigates all of these risks by performing a detailed field inspection during the design phase. Toronto Hydro can complete corrective work on flooded vaults prior to starting construction work for this program. To address a lack of suitable available space to install equipment, such issues will be proactively identified, and the relevant project will be designed to include the necessary equipment relocation work and scheduled to avoid impacting the program's critical path timeline. Where existing primary feeder installations interfere with installation of a particular transformer sensor and incompatible legacy network protectors, Toronto Hydro will complete a network unit renewal and then install NCMC capabilities.

E7.3.6.3 Material Delays

Supply chain issues can cause delays in receiving material for all NCMC components and therefore delay execution of projects, as was the case with VCBs in the 2020-2024 rate period, as discussed in section E7.3.4.1. Toronto Hydro mitigates this risk by ensuring all relevant stakeholders are engaged to proactively identify issues and develop solutions, such as developing new standards that increase options available. This is also mitigated through Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue, please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E7.3.6.4 Security and Privacy Issues

Once the initial plan of the program is completed, Toronto Hydro plans to introduce enhanced monitoring capabilities, which may include vault cameras and vault hatch open sensors. These two sensors pose security and privacy issues that need to be resolved prior to planning installations. However, Toronto Hydro is making investments in IT Cybersecurity to ensure that current systems, applications, and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to an evolving threat landscape, please refer to Exhibit 2B Section E8.4 for more details.

In addition, secondary cable monitoring sensors will pose data overload issues and cables identified for sensor installation need to be carefully selected to provide useful benefits for system emergency operations as well as planning enhancements. These concerns will be discussed with the appropriate stakeholders before rolling out these sensors, and will be considered alongside other modernization initiatives in the context of Toronto Hydro's broader analytics strategy.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 139.9	**2025-2029 Cost ($M):** 173.2
Segments: Downsview TS, Hydro One Contributions[1]	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Public Policy Responsiveness, Environment	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium to long-term system capacity needs. The Program is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Increased and continued densification, population growth, and electrification are driving the need to relieve the station loading and create additional capacity. If not addressed proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system, and expose Toronto Hydro's stations to risk during peak loading periods. The primary focus of the work planned in the 2025-2029 rate period is on the horseshoe northwest and horseshoe east regions of the distribution system, where constraints currently exist or are forecasted to materialize with growth.

The Stations Expansion program consists of the two segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Downsview TS**: This segment aims to expand station capacity by constructing a new transformer station ("TS") in the Downsview area of Toronto, with a capacity of 174 MW. Additional capacity is needed to support forecasted growth and development in the City's Downsview area, while relieving the highly-loaded Bathurst and Finch TSs. A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035.[2] The construction of a new TS is a large project requiring a long lead time. In order to be ready to meet the forecasted demand, Toronto Hydro must start planning and preparing for this project in the

[1] EB-2018-0165, Exhibit 2B, Section E7.4
[2] Downsview Area Secondary Plan – Electricity Demand Justification Report by DMP Energy (Aug 08 2022)

2025-2029 rate period for an anticipated energization date of late 2033. This planning and preparation stage will include preparatory capital investments such as: property acquisition, property site preparation construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[3] Toronto Hydro forecasts to spend $70.2 million in this stage. Once planning and preparation is complete, Toronto Hydro will move into the construction and energization stage, which will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. Toronto Hydro forecasts to spend $70.0 million during the commissioning and energization stage post-2029.

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
    - Downsview SS: A new Hydro One switching station to provide Toronto Hydro's new Downsview TS access to Hydro One's transmission network;
    - Scarborough TS Expansion: A new Dual Element Spot Network ("DESN") at the existing Scarborough TS to provide relief to the Horseshoe East area and support future load growth;
    - Sheppard TS New Switchgear: A new switchgear to provide access to existing idle capacity at the existing Sheppard TS and enable new Distributed Energy Resources (DER) connections [E3.3 Capacity and Constraints to Connect DER];
    - Manby TS T13/T14 DESN Upgrade: An upgrade to the transformers at this DESN during their natural end-of-life (EOL) renewal and an expansion of the switchyard to accommodate new feeders, to facilitate future load growth at this highly loaded station; and
    - Cost-effective capacity upgrades of EOL Hydro One-owned power transformers, as anticipated based on the IRRP process and latest Planning work in 2022.[4]

  Toronto Hydro plans to invest an estimated $103.0 million in this segment in the 2025-2029 rate period compared to a forecasted $60.4 million in 2020-2024.

The investments summarized above for Hydro One transformer replacement are informed by the recent Regional Infrastructure Plan ("RIP") and 2020 Integrated Regional Resource Plan ("IRRP")

[3] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.
[4] Hydro One Needs Assessment Report, Toronto Region, Dec 2022

activities conducted in coordination with Hydro One. The most recent planning document from this process is the 2022 Needs Assessment Report for the Toronto Region ("Needs Assessment"). A reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 Regional Planning Needs of this narrative.

The Stations Expansion program also responds to the need to maintain system reliability and increase grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

In total, Toronto Hydro plans to invest $173.2 million in the Stations Expansion Program in 2025-2029, compared to a forecasted $139.9 million in 2020-2024. Toronto Hydro expects to add 321 MW of new capacity to its system from projects completed by 2029, and start projects that will contribute to an additional 269 MW of capacity when completed in 2030-2034.[5]

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 321 MW in additional supply capacity by 2029; ○ Alleviating feeder position limitations that prevent customer connections; and ○ Enabling new DER connections by providing increased short-circuit capacity with new DESNs.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system capacity and reliability objectives by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas;

[5] The Downsview TS and Scarborough TS Expansion projects will contribute 271 MW of new capacity and are forecasted to come in-service during the 2030-2034 rate period.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the provincial long-term energy planning and IRRP by meeting local needs; and ○ Enabling electrification by investing in additional capacity and operational flexibility.
Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability, DER Connections

The Stations Expansion program is driven by constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Over the next decade, Toronto Hydro's distribution system is expected to face many new challenges and demands due to population growth, densification, and electrification. These factors will ultimately result in increased capacity constraints at its stations, creating the need to relieve constraints by building additional capacity.

Because these challenges, particularly the acceleration of electrification, are subject to many factors outside of Toronto Hydro's control, such as government policies and consumer preferences, the timing for when capacity constraints will materialize is uncertain. Toronto Hydro has managed this uncertainty by considering multiple inputs to develop a plan that will satisfy its capacity needs, in a least-regrets investment approach. These inputs are as follows.

- **Load Forecasts:** Toronto Hydro's 10-Year Peak Demand Forecast (see Section D of the Distribution System Plan), and Hydro One's Needs Assessment Report 10-Year Load Forecast
- **City of Toronto Development Plans:**[6] Downsview Area Secondary Plan, East Harbour Development, Golden Mile Secondary Plan, and Scarborough Centre Secondary Plan

[6] City of Toronto, Secondary Plan Key Map (November 2015) https://www.toronto.ca/wp-content/uploads/2017/11/980a-cp-official-plan-Map-35_SecondaryPlans_AODA.pdf

- **Future Energy Scenarios ("FES"):**[7] Six scenario-based outlooks to assess impacts to station loading due to: the electrification of heating and transportation, building stock growth, and DER integration.

From this analysis, Toronto Hydro identified that the City of Toronto Development Plans will be a primary driver of forecasted load growth in both the Downtown and the Horseshoe areas. Toronto Hydro expects that these plans will result in load growth that will add constraints to the Bathurst TS and Scarborough TS areas over the next 5-10 years.

A second key driver of forecasted load growth identified is electrification, which is forecasted to impact Toronto Hydro's system more broadly than the Secondary Plans which target specific areas. This is driving a need for capacity to be made available throughout Toronto Hydro's system, to ensure that Toronto Hydro's system does not become a barrier to new customers looking to access its system, regardless of where those customers may materialize.

The lack of capacity at Toronto Hydro's stations results in two negative consequences. First, it negatively impacts customer connections by preventing new customers from connecting to the grid or burdening connecting customers with higher connection costs. Second, it reduces the reliability of the station, and may result in load shedding.[8]

When a customer submits a connection request to a station which is highly loaded, Toronto Hydro can either connect the customer to the highly loaded station by first completing a load transfer, or to another station with capacity further away resulting in a higher connection cost. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs become even higher.

When station load exceeds capacity, equipment losses result in customer outages during periods of peak loading. As a result, Toronto Hydro or Hydro One is not able to complete maintenance or replacement work during peak periods, which typically results in the deferral of work needed to maintain station reliability. To otherwise complete the work during peak periods would result in a shortened life of the existing station assets, which cannot be readily replaced. A lack of station

[7] Exhibit 2B Section D4 Capacity Planning & Electrification

[8] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant consequences in the event of an outage, Toronto Hydro would be required shed load[8] to maintain station load within its capacity.

Hydro One's 2022 Needs Assessment, as part of Regional Planning identifies station capacity needs at: Bathurst and Finch TSs, Basin TS, Fairbank TS, Glengrove TS, Sheppard TS, Strachan TS, and Warden TS. The Report also recommends incremental capacity upgrades at Basin TS, Duplex TS, Manby TS, and Strachan TS during renewal work. Toronto Hydro's analysis has reached similar conclusions; and as a result, the work planned under the Stations Expansion Program is aligned with the NA needs and those in the 2020 Regional Infrastructure Plan ("RIP") report.[9] Table 4 and Table 5 below highlight the needs and how they are addressed through the Stations Expansion program.

The IESO's Integrated Regional Resource Plan ("IRRP")[9] for the Toronto Region is currently underway, and as a result, IRRP needs and recommendations have not been produced at this time. However, Toronto Hydro is presenting the same needs to the Toronto IRRP Working Group as those presented in the Stations Expansion Program.

Table 4: Station Capacity Needs from Needs Assessment and RIP

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Bathurst TS / Finch TS	*Beyond 2031*	*7.3.6*	*N/A*	See E7.4.3.2.1
Basin TS	*2030-2035*	*7.3.4*	*7.9.4*	See E7.4.3.2.2
Fairbank TS	*2030-2035*	*7.3.1*	*7.9.1*	Included in 2020-2024 Stations Expansion plan, and in E7.4.3.2.1.
Glengrove TS	*Beyond 2031*	*7.3.5*	*N/A*	Addressed with new capacity at Duplex TS in E7.4.3.2.6
Sheppard TS	*2030-2035*	*7.3.2*	*7.9.2*	See E7.4.3.2.4

[9] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Strachan TS	*2030-2035*	*7.3.3*	*7.9.3*	Addressed through transformer upgrade in E7.4.3.2.6
Warden TS	*Beyond 2031*	*7.3.7*	*N/A*	See E7.4.3.2.3

Table 5: NA Asset Renewal Needs where Upgrade is Recommended in NA and RIP

Asset Renewal Need	Renewal Timing[10]	Needs Assessment Section	RIP Report Section	Stations Expansion Narrative
Basin TS T3/T5 Transformers	*2027*	*7.1.4*	*N/A*	See E7.4.3.2.6
Charles TS T3/T4 Transformers	*2026*	*7.1.2*	*N/A*	
Duplex TS T1/T2 Transformers	*2026*	*7.1.3*	*N/A*	
Duplex TS T3/T4 Transformers	*2031*			
Manby TS T13/T14 Transformers	*2030*	*7.1.9*	*7.6*	
Strachan TS T14 Transformer	*2025*	*7.1.1*	*N/A*	
Strachan TS T13/T15 Transformers	*2031*			
Windsor TS (John TS) T2/T3 and T5/T6 Transformers	*2026*	*N/A*	*7.8*	Included in 2020-2024 Stations Expansion plan.

The station expansion program continuously improves and expands Toronto Hydro's grid in order to align itself with the City's growth and electrification endeavors. The work in the station expansion program will make Toronto Hydro's system more resilient to sudden load demands, and will ensure sufficient capacity exists to ensure station reliability.

[10] If present in both the NA and RIP, the NA timing is used, as the NA is the more recent document.

The system needs are addressed through two segments: Downsview TS and Hydro One Contributions, as further discussed below.

E7.4.3.1 Downsview TS

The area affected by the Downsview TS segment consists of: Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area will be called the "Downsview Area" throughout the rest of this document. The Downsview Area is show in Figure 1.

In recent years, the Downsview Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. On average, the area is forecasted to grow by 2.2 percent per annum over the next 10 years.

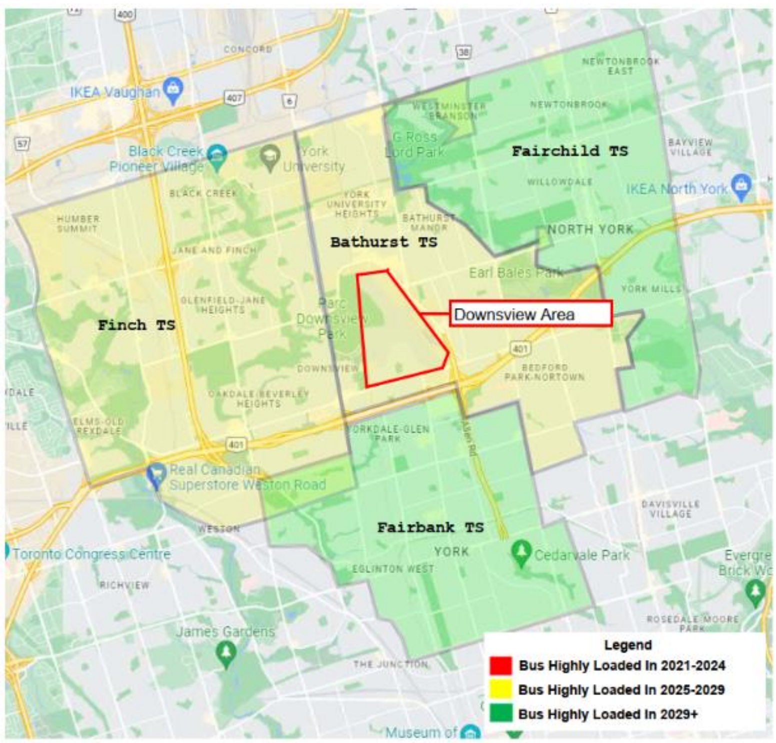


Figure 1 : Service Territories of Stations in the Downsview Area

1. Toronto Hydro's Peak Demand Forecast

Table 6 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 6 : Non-Coincident Downsview Area 10-Yr Load Forecast[11]

Station	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	73%	78%	79%	85%	86%	86%	85%	85%	85%	85%	85%
Fairbank TS	182	104%	104%	94%	93%	95%	97%	97%	98%	100%	101%	103%
Fairchild TS	346	61%	67%	67%	69%	69%	69%	70%	70%	70%	71%	71%
Finch TS	366	69%	77%	90%	98%	100%	102%	102%	103%	104%	105%	107%
Area Non-Coincident %	1255	73%	78%	81%	85%	86%	88%	88%	88%	89%	89%	90%

Fairbank TS and Finch TS are forecasted to be highly loaded during the 2025-29 rate period, with both stations forecasted to be overloaded by 2029. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. Some capacity remains at Bathurst TS, but not enough to relieve overloading. Fairchild TS remains as the only station with significant capacity in the Downsview Area, but it cannot provide direct relief to the highly loaded Fairbank and Finch TSs, due to geography.

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2031. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below.

[11] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

2. Downsview Area Secondary Plan ("DASP")

The Downsview Lands are approximately 210 hectares (520 acres) situated in the City of Toronto, bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2. The lands reside within the Bathurst TS service territory, as shown in Figure 1.

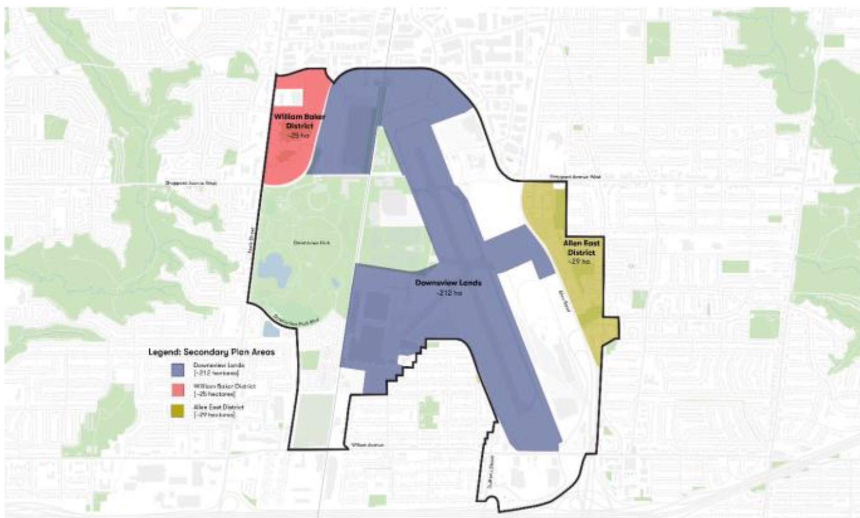


Figure 2: Proposed Downsview Secondary Plan Lands

The City of Toronto plans to redevelop the Lands into a dense new community as described in their Downsview Area Secondary Plan ("DASP"), published in 2017.[12] The DASP divides the Downsview Lands into districts and describes the expansion of each district with a mix of commercial, office, industrial and institutional buildings. The DASP preceded the city's net zero 2040 plans but is to align with the adoption of current day power demands of 6W per square foot and EV chargers for the projected EVs by 2045.

An independent party, DPM Energy, completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in

[12] City of Toronto, Downsview Area Secondary Plan, "online", https://www.toronto.ca/wp-content/uploads/2017/11/902d-cp-official-plan-SP-7-Downsview.pdf

Table 6. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

The Peak Demand Forecast only extends to 2031, and already considers load growth from the DASP. However, the DASP is expected to result in load growth up to 2051, with the majority of load materializing after 2031. Therefore, in order to ensure that cost-effective decisions are made now for the long term, Toronto Hydro has developed a 25 Year Forecast for the Downsview Area which considers the impact of the DASP from 2029 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the DASP for 2032-2051 is adjusted to 70 percent.**
    - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30 percent reduction to the DASP load for 2032-2051 is offset by:**
    - Load growth due to electrification of heating and transportation in the Downsview Area, in alignment with municipal and federal decarbonization goals.
    - General load growth in the Downsview Area, beyond the Downsview Lands.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Downsview Area for post-2031. The results appear in Table 7.

Table 7 : Post-2031 Forecast for Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	86%	90%	98%	108%	117%	2040
Fairbank TS	182	111%	115%	124%	133%	142%	2029
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	110%	113%	117%	121%	126%	2025
Area Non-Coincident %	1255	93%	95%	100%	105%	111%	2039

This forecast shows that by 2039 the Downsview Area as a whole will reach capacity, with substantial load growth continuing past then. Prior to that, significant overloading is forecasted at Fairbank TS and Finch TS, which cannot be directly relieved by Fairchild TS, the only station with capacity, due to geography. The 25 Year Forecast indicates that regional capacity constraints will persist past the medium term, and worsen further into the long term.

3. Load Projections – FES

To consider the impacts that the electrification of heating and transportation, building stock growth, and DER integration may have on Toronto Hydro's station loading, Toronto Hydro completed the FES[7]. The FES produced six 30-year system and station bus load projections based on different scenarios.

The FES incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any DASP load. The results from the FES outlooks are provided in Table 8.

Table 8 – FES Projections for the Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Bathurst TS	361	84-94%	89-101%	95-114%	99-118%	98-122%	2034-N/A
Fairbank TS	182	120-132%	124-142%	130-167%	132-174%	131-180%	2021
Fairchild TS	346	68-74%	69-78%	70-84%	70-85%	69-86%	N/A
Finch TS	366	113-122%	118-133%	124-150%	127-153%	126-156%	2024
Area Non-Coincident %	1255	93-102%	97-109%	102-122%	104-126%	103-129%	2030-2037

Across all FES projections, all but one station will become heavily loaded by 2035. Additionally, the Downsview Area is to become highly loaded between 2025-28, and overloaded between 2030-37. Consistent with the Peak Demand Forecast and Toronto Hydro's post-2031 Forecast, the FES projections indicate high loading in the 2025-29 rate period, and a regional need for additional capacity that increases with time.

[13] According to the FES only. As a result, this year may be earlier than what is provided in the Needs Assessment.

4. Proposed Solution – New Downsview TS

In order to address both medium- and long-term regional needs for additional capacity in the Downsview Area, Toronto Hydro proposes to build a new transformer station, named Downsview TS. The objective of the new Downsview TS is both to provide load relief to the existing TSs in the Downsview Area, and to directly supply the new loads resulting from the DASP and electrification.

Downsview TS is proposed to be located within the Downsview Lands, within the Bathurst TS service territory. This location has been chosen so that it may directly supply local DASP loads, and because it is also a central location between Bathurst TS, Fairbank TS, and Finch TS. As a result, the station will be well-placed to offload the three highest loaded stations in the Downsview Area. Downsview TS will provide 174 MW of new capacity to supply the Downsview Area, increasing the Area's capacity by an additional 14%.

There will be both a Toronto Hydro and Hydro One component of work to construct the new Downsview TS. The Hydro One portion is discussed in E7.4.3.2 and involves the construction of a new Downsview Switching Station ("Downsview SS"), which will serve as the connection point to Hydro One's transmission network.

The construction of a new TS is a large project requiring a particularly long lead time, and for this reason, a portion of the work needed to build the new TS was advanced into the 2025-2029 rate period. In order to energize Downsview TS at the end of 2033, Toronto Hydro forecasts that work must begin in 2025. Toronto Hydro has planned for the Downsview TS project to proceed in two stages. The Planning and Preparation stage and the Construction and Energization stage.

The Planning and Preparation stage will proceed over the 2025-2029 rate period, and will include preparatory capital investments such as: property acquisition, property site preparation, construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[14] The cost to complete this stage is forecasted to be $70.2 million.

The Construction and Energization stage will proceed starting in 2030 and will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning

[14] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.

and energization of all electrical assets. The remaining electrical assets include: a new 230 kV underground cables from Downsview SS, two new transformers, and one new switchgear. Toronto Hydro forecasts to spend $70.0 million during this stage, excluding the Hydro One contributions related to Downsview SS (see E7.4.3.2 – 1.).

Because the forecasted in-service date is beyond the range of the Peak Demand Forecast, the effect of Downsview TS is provided using the Post-2031 Forecast and the FES load projections, and shown in Figure 3. With the addition of new capacity at Downsview TS, the Downsview Area loading is expected to be manageable out to 2041; after that the Area is again expected to be highly loaded, with a risk of overloading. FES Projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS is proposed to be constructed with the provision to install a second DESN in the future, when it is needed.

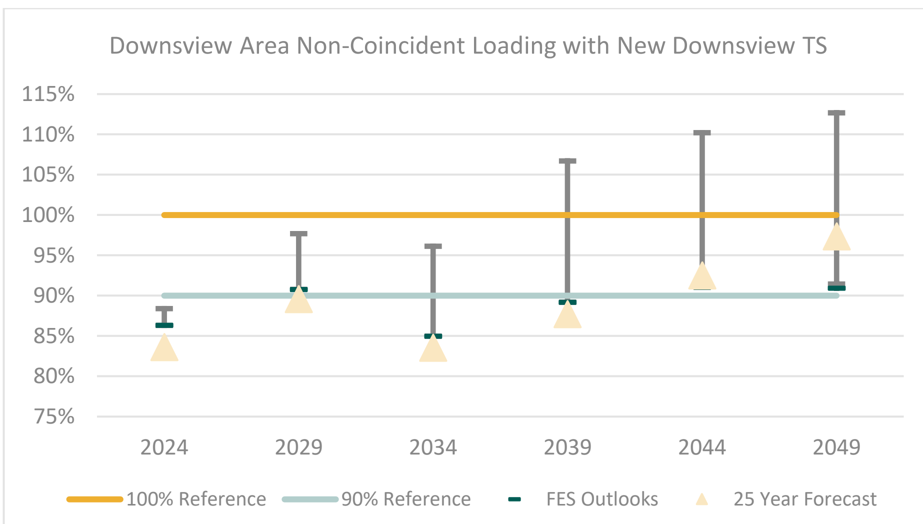


Figure 3 : Downsview Area Loading Outlooks After Downsview TS is In-Service

Toronto Hydro believes that the proposed solution strikes the right balance between the risk of capacity constraints and cost in least-regrets investment approach. Toronto Hydro will continue to monitor the actual and forecasted load of the Downsview Area to assess the risk of capacity constraints shortly after Downsview TS is completed. If this risk persists, Toronto Hydro may consider introducing another DESN into the Downsview Area at a later time; however, it would not be in the best interest of the ratepayer to invest immediately in two new DESNs. For this reason, the proposed solution includes only one new DESN, which is expected to provide adequate capacity until 2041.

E7.4.3.2 Hydro One Contributions

The most recent Needs Assessment reaffirms needs that were identified in the IRRP and highlights additional emerging needs. These needs are summarized in Table 32, Table 33, and Table 34 in Section E7.4.7.

In response, Toronto Hydro plans to make capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2025-2029 rate period, as detailed in the following subsections.

1. **New Downsview SS**

Toronto Hydro plans to make a capital contribution to Hydro One over the 2025-2029 rate period to support their construction of a new Hydro One-owned Downsview SS. As discussed in section E7.4.3.1 above, the Downsview TS will provide additional capacity of 174 MW to alleviate forecasted constraints in the Downsview Area. Hydro One will support the project by constructing a new switching station, Downsview SS, to supply Downsview TS from the Hydro One 230 kV transmission line corridor. Toronto Hydro will construct and own the TS itself.

2. **Scarborough TS Expansion**

The area affected by the Scarborough TS expansion consists of: Bermondsey TS, Ellesmere TS, Scarborough TS, and Warden TS. This area will be called the "Scarborough Area" throughout the rest of this document. The Scarborough Area is show in Figure 4.

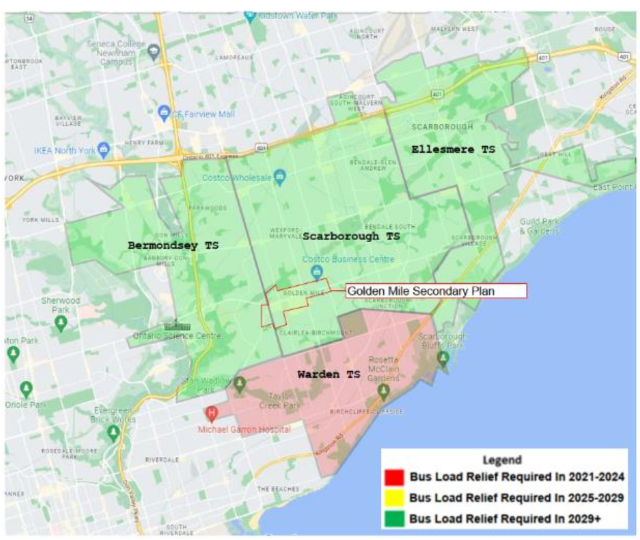


Figure 4 : Service Territories of Stations in the Scarborough Area

a. *Toronto Hydro's Peak Demand Forecast*

In recent years, the Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. Recent large projects in progress involve an 84 MVA data centre, an 80 MVA Metrolinx connection for the Ontario Line, and a 36 MVA TTC connection for the Scarborough Subway Extension. On average, the area is forecasted to grow by 4.1 percent per annum over the next 10 years.

Table 9 shows the existing load forecast for the stations in the Scarborough Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 9: Non-Coincident Scarborough Area 10-Yr Load Forecast15

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bermondsey TS	348	45%	57%	67%	71%	73%	73%	85%	85%	85%	86%	88%
Ellesmere TS	189	63%	65%	71%	84%	88%	88%	89%	95%	96%	96%	96%
Scarborough TS	340	64%	68%	71%	78%	79%	79%	79%	84%	85%	86%	86%
Warden TS	182	80%	85%	78%	91%	92%	94%	93%	93%	94%	94%	95%
Area Non-Coincident %	1059	60%	67%	71%	79%	81%	81%	85%	88%	88%	89%	90%

Loading at all four stations in the Scarborough Area is forecasted to rapidly increase due to the onset of new large customer connections. Warden TS and Ellesmere TS particularly are forecasted to become highly loaded during the 2025-29 rate period. These two TSs will not be able to accommodate new large connection requests without first initiating load relief projects. By 2031, the entire Scarborough Area is forecasted to be highly loaded at 90% of capacity. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering impacts to the Scarborough Area resulting from the Golden Mile and Scarborough Centre Secondary

[15] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

Development Plans, and its Future Energy Scenarios projections. These are described in the subsections below.

b. Golden Mile Secondary Development Plan ("GMSDP")

In 2020, the City of Toronto adopted the Golden Mile Secondary Plan, which proposes a mixture of residential, commercial, and office building development. The Golden Mile is 113 hectares (280 acres) in size, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south, as shown in Figure 5. The location of the Golden Mile relative to Toronto Hydro's station service territories is shown in Figure 4 in the previous section.

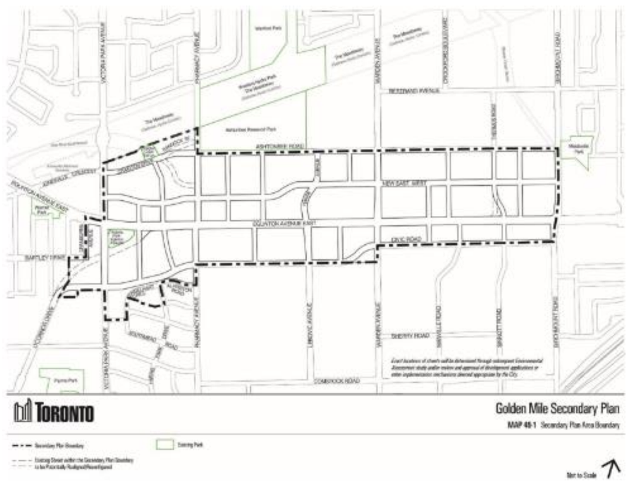


Figure 5 *:* Proposed Golden Mile Secondary Plan Lands

New developments are to include a mixture of mid-rise and tall buildings, creating up to 5,000 new residential units. Additionally, the Plan proposes for each dwelling unit to provide an energized outlet for EV charging. Based on the Plan, an independent party has completed a preliminary study which estimates the electrical demand that will materialize from the Golden Mile Secondary plan. This study suggests that load will begin to materialize in 2030 and could materialize up to 280 MW by 2040. This is equivalent to 26 percent of the existing Scarborough Area's Summer LTR of 1059 MW, as provided in Table 9. As a result, supplying the Golden Mile with existing regional capacity will be challenging at best in the short term, and infeasible in the long term.

The Peak Demand Forecast only extends to 2031, and does not already explicitly consider the GMSDP. In order to ensure that cost-effective decisions are made now for the long term, Toronto

Hydro has developed a 25 Year Forecast for the Scarborough Area which considers the impact of the GMSDP from 2030 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the GMSDP for 2030-2051 is adjusted to 70%.**
   - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30% reduction to the GMSDP load for 2030-2051 is offset by:**
   - Load growth due to electrification of heating and transportation in the Scarborough Area, in alignment with municipal and federal decarbonization goals.
   - General load growth in the Scarborough Area, beyond the Golden Mile.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Scarborough Area for 2030 onwards. The results are provided in Table 10.

Table 10: Post-2031 Forecast for Scarborough Area

Station	Summer LTR (MW)	2030	2034	2039	2044	2049	Year 100% Capacity is Reached
Bermondsey TS	348	88%	93%	99%	101%	102%	2040
Ellesmere TS	189	96%	96%	96%	96%	96%	N/A
Scarboro TS	340	88%	96%	110%	113%	114%	2036
Warden TS	182	97%	105%	117%	121%	122%	2032
Area Non-Coincident %	1059	91%	97%	105%	107%	108%	2036

c. *Load Projections – Future Energy Scenarios*

The Future Energy Scenarios model considers the long-term impacts that the electrification of heating and transportation, building stock growth, DER integration and other energy transition variables may have on Toronto Hydro's station loading based on six different scenarios.[16] The Future

[16] Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview.

Energy Scenarios incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any GMSDP load. The results from the Future Energy Scenario outlooks are provided in Table 11.

Table 11: FES Projections for Scarborough Area

Station	Summer LTR (MW)	2030	2034	2039	2044	2049	Year 100% Capacity is Reached[17]
Bermondsey TS	348	79-84%	82-89%	84-**95%**	85-**96%**	84-**97%**	N/A
Ellesmere TS	189	101-117%	109-135%	120-154%	128-58%	120-61%	2028-2029
Scarborough TS	340	88-96%	95-107%	100-118%	104-20%	104-23%	2032-2039
Warden TS	182	126-136%	135-151%	140-174%	144-81%	143-86%	2024
Area Non-Coincident %	1059	94-101%	100-111%	104-123%	107-26%	106-29%	2030-2034

Across all scenarios, the Future Energy Scenarios project that all but one station will become highly loaded by 2031, and that the area as a whole will become overloaded between 2030 and 2034. The Future Energy Scenarios reinforces the need for new capacity in the Scarborough Area for the end of the 2025-2029 rate period, and shows that this need may progress much more rapidly than predicted by the Peak Demand Forecast or the Past-2031 Load Projection.

d. <u>Proposed Solution – Scarborough TS Expansion</u>

In order to address both medium- and long-term needs for additional capacity in the Scarborough Area, Toronto Hydro proposes to upgrade the T23 transformer at Scarborough TS, as recommended in the Needs Assessment, and also to install a new DESN at the station. The objective of the expansion is both to provide load relief to existing TSs in the Scarborough Area, and to directly supply the new loads resulting from the GMSDP.

Out of the four stations within Scarborough Area that were analyzed, Scarborough TS was chosen due to the location to the incoming load as well as the station being a central location between

[17] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

Bermondsey TS, Ellesmere TS and Warden TS. As a result, the station will be well-placed to offload the other stations in the Area when required.

The Scarborough TS T23 transformer upgrade will provide an estimated 38 MW new capacity to the Scarborough Area by 2028 and will help to relieve short-to-medium term constraints. Following this, the proposed new DESN will provide a further 95 MW to the Area, with the provision to install another 95 MW through a bus expansion when needed in the future. This additional capacity will address medium-to-long term needs.

The scope of work to install the new DESN will be similar to that of the Horner TS expansion completed in the 2020-2024 rate period, and is outlined in the Scarborough TS Bus Expansion subsection of E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions. The in-service date for the new DESN is estimated to be Q4 2030.

Because the forecasted in-service date is beyond the range of the Stations Load Forecast, the effect of Scarborough TS is provided using the using the Post-2031 Forecast and the FES load projections and shown in Figure 6. With the addition of new capacity at Scarborough TS, the Scarborough Area loading is expected to be manageable beyond 2050. FES Projections show that there is a risk of area overloading by 2035, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Scarborough TSs new DESN will include idle windings to install a second switchgear in the future, when it is required.

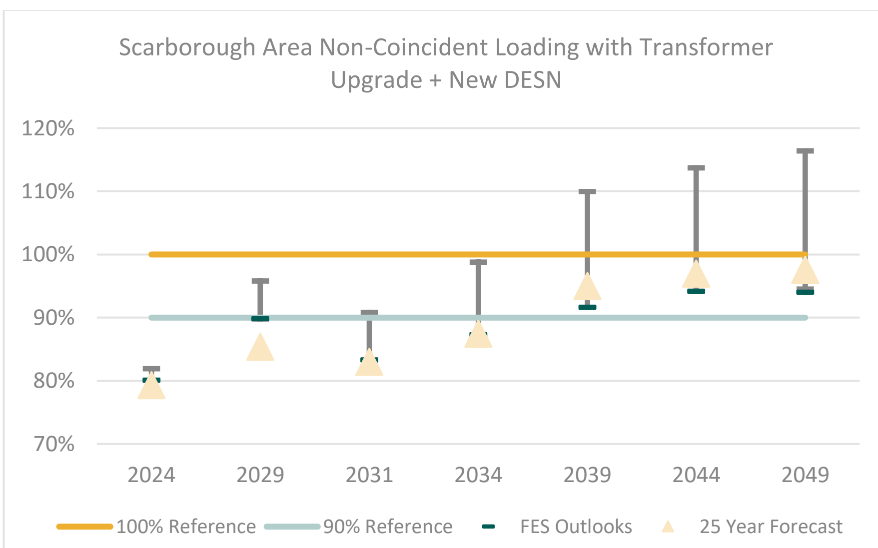


Figure 6: Scarborough Area loading Following Transformer Upgrade and NEW DESN

Toronto Hydro's proposed solution will address the short-term load demand of the Area as well as the medium-to-long term load from GMSDP. Toronto Hydro will continue to monitor the actual and forecasted load of the Area to assess the risk of capacity constraints shortly after the Scarborough TS expansion is completed. If the Area were to become at risk of overloading, Toronto Hydro may install a second switchgear at Scarborough TS to further increase the station capacity by another 95 MW. However, since there is no immediate need for two switchgear and 190 MW of new capacity, the proposed solution includes only one new switchgear and is expected to provide adequate capacity to 2050.

3. Sheppard TS Bus Expansion

The area affected by the Sheppard TS bus expansion consists of: Malvern TS, and Sheppard TS. This area will be called the "Sheppard Area" throughout the rest of this document. The Sheppard Area is shown in Figure 7, and is adjacent to Ellesmere TS (part of the Scarborough Area) which is shown in a dashed line.

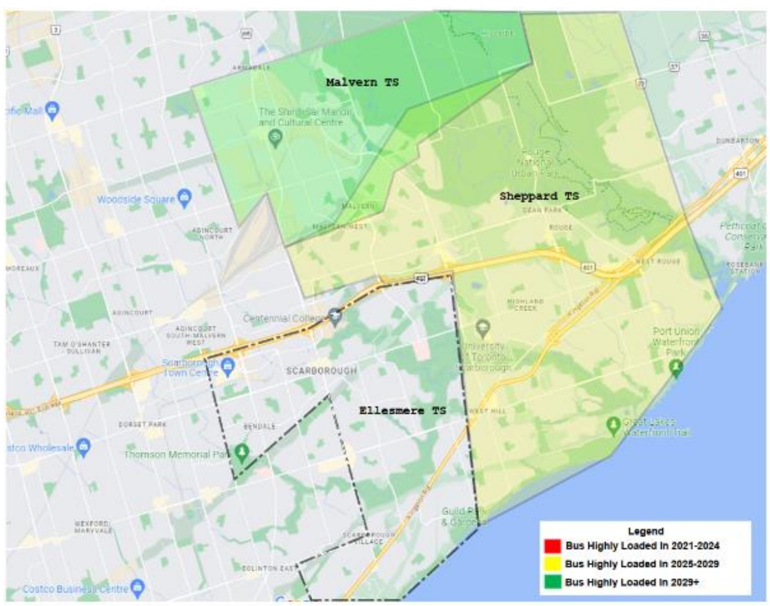


Figure 7 : Service Territories of Stations in the Sheppard Area

Table 12 shows the existing load forecast for the stations in the Sheppard Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 12: Non-Coincident Sheppard Area 10-Yr Load Forecast18

Station	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Malvern TS	176	60%	58%	58%	61%	63%	64%	65%	66%	66%	67%	68%
Sheppard TS	204	77%	81%	82%	85%	86%	87%	89%	89%	90%	91%	92%
Area Non-Coincident %	380	69%	70%	71%	74%	75%	77%	78%	79%	79%	80%	81%

Sheppard TS is forecasted to be highly loaded by 2029, and since the Peak Demand Forecast has been produced, Toronto Hydro has received a new customer request for an additional 20 MW in the Sheppard TS service area. This request will nearly consume the remaining capacity forecasted for Sheppard TS, resulting in a need for load relief. In contrast, Malvern TS is forecasted to have excess capacity.

An additional constraint at Sheppard TS is the lack of short circuit capacity. As discussed in the Generation Protection, Monitoring, and Control Program ("GPMC Program"), short circuit capacity is a requirement to connect new DERs to Toronto Hydro's system. The GPMC Program also states that the available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, and is forecasted to be -91.4 MVA in 2029. Therefore, in order to ensure that its system does not act as a barrier to new DER connections, Toronto Hydro must relieve both thermal and short circuit capacity constraints at Sheppard TS.

While Malvern TS has spare thermal capacity which can provide load relief to Sheppard TS through load transfers, it is much more challenging and expensive to address short circuit capacity constraints through load transfers.[19] The existing configuration of Sheppard TS also presents a unique opportunity to expand the station for a significantly reduced cost and in a shorter timeframe than comparable expansion projects.[20] This is because the station is already equipped with idle

[18] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.
[19] To provide short circuit capacity through load transfers, specific feeders or sections of feeders connecting large DERs must be transferred. The limited number of large DERs on each feeder makes this a challenging exercise and typically cannot be done in bulk. Furthermore, protection systems for large DERs also need to be transferred over from one station to another and recommissioned, which adds further costs and complexities compared to typical load transfers.
[20] Comparable projects include the Runnymede TS expansion project from the 2015-2019 CIR, the Horner TS expansion project from the 2020-24 CIR, and the newly proposed Scarborough TS expansion project for the 2025-29 CIR.

transformer windings, and as a result, the scope of work would not include transmission or transformation components.

When considering both thermal and short circuit capacity needs, and the significantly reduced cost of expansion presented at Sheppard TS, Toronto Hydro concluded that the expansion of Sheppard TS would present the best value to customers. The expansion of Sheppard TS would involve the installation of a new switchgear, and would provide 95 MW of thermal capacity and an estimated 126 MVA of short circuit capacity.

Sheppard TS is also adjacent to the Scarborough Area, which as discussed in the previous section, is at risk of becoming highly loaded by 2037, despite the expansion of Scarborough TS. As a result, any excess capacity at Sheppard TS may be used to partially manage the long-term loading of the Scarborough Area.

4. Manby TS DESN Reconfigurations

The area affected by the Manby TS DESN Replacements Preparations ("DESN RPs") consists of: Horner TS, Manby TS, and Richview TS. This area will be called the "Manby Area" throughout the rest of this document. The Manby Area is shown in Figure 8.

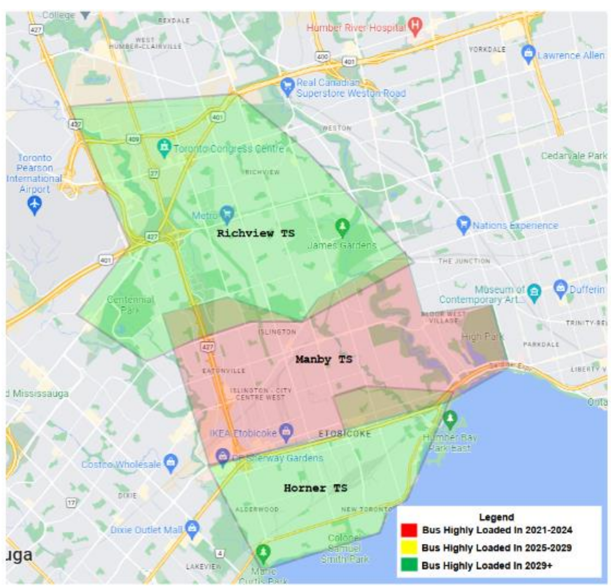


Figure 8 : Service Territories of Stations in the Manby AreaTable 13 shows the existing load forecast for the stations in the Manby Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 13: Non-Coincident Manby Area 10-Yr Load Forecast[21]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Horner TS	366	40%	35%	50%	53%	53%	62%	62%	62%	63%	63%	63%
Manby TS	226	109%	89%	91%	99%	99%	87%	89%	90%	92%	94%	96%
Richview TS	460	63%	66%	66%	64%	64%	64%	65%	63%	64%	63%	61%
Area Non-Coincident %	1052	65%	60%	66%	68%	68%	69%	69%	69%	69%	70%	69%

Due to the recent Horner TS expansion completed during the 2020-2024 rate period, the Manby Area is forecasted to have excess capacity to 2031. However, due to forecasted high loading at Manby TS specifically, and given the T13 and T14 transformers require renewal, the Hydro One 2022 Needs Assessment ("NA") Report recommends the upgrade of the Manby TS T13 and T14 transformers to the current standard size of 125 MVA. These upgrades are mentioned in the following Section "Hydro One Transformer Upgrades".

Because of the existing configuration at Manby TS, if the transformer replacements proceed without any reconfiguration of its associated DESN, then the DESN will actually decrease in capacity by 15 MW. Although the new T13 and T14 transformers will be rated at higher capacity, their additional capacity will be locked in idle windings, similar to the current configuration at Sheppard TS. However, the upgrade of the T13 and T14 transformers can provide additional renewal and long-term capacity benefits, if its DESN is reconfigured from the existing Jones configuration to a Bermondsey configuration in coordination with the transformer upgrades.[22][23]

The T3/T4 switchyard at Manby TS will require renewal in the near future. The existing T3/T4 DESN is under-rated which has made managing its load difficult. Rather than replace the T3/T4 switchyard like-for-like and the T13 and T14 transformers life-for-like, Toronto Hydro proposes to upgrade the T13 and T14 transformers (as recommended in the Needs Assessment) and also replace both the existing T13/T14 Jones switchyard and the T3/T4 Jones switchyard with one new Bermondsey

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[21] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

[22] A DESN in Jones configuration is composed of two single-winding transformers and two buses, with one transformer supplying each bus, and a normally-closed bus tie connecting the two buses to one another.

[23] A DESN in Bermondsey configuration is composed of two dual-winding transformers and two buses. One winding from each transformer supplies each bus, and a normally-open bus tie is installed between the buses.

switchyard. The new Bermondsey switchyard will be supplied by the upgraded T13 and T14. In summary, two existing Jones switchyards will be replaced with one new Bermondsey switchyard.

The near-term benefits of this proposal are as follows.

- No loss of capacity for the T13/T14 switchyard;
- Increase in station capacity by +16 MW once both switchyards are replaced;
- Higher reliability replacement plan for the T3/T4 switchyard, rather than replacing the switchyard "in-place" while still supplying customers;
- Fully-rated new Bermondsey switchyard can properly manage the combined load of the existing T3/T4 and T13/T14 DESNs;

In addition, this proposal presents two subsequent long-term options to increase station capacity at Manby TS when needed:

1. When the T3/T4 switchyard is replaced onto the new Bermondsey switchyard, the existing T3/T4 will be left idle in a similar configuration as what currently exists at Sheppard TS. As a result, Toronto Hydro can initiate for a new 60 MW switchyard to be installed using the idle windings, and thereby increase station capacity by 60 MW; or,
2. At the time when the third and last DESN at Manby TS requires renewal, if Toronto Hydro has not pursued the above option, then Toronto Hydro may be able to replace the last DESN and the idle T3/T4 with another new Bermondsey-configured DESN. This would increase the station capacity by approximately 123 MW.

Therefore because of both the near-term and long-term benefits to the renewal and upgrade of Manby TS, Toronto Hydro proposes to replace the existing T3/T4 and T13/T14 switchyards with a new Bermondsey switchyard, in coordination with the T13 and T14 transformer upgrades. This proposal is being referred to as "DESN Reconfigurations".

5. Hydro One Transformer Upgrades

To alleviate capacity constraints, Toronto Hydro proposes to invest in incremental upgrades to Hydro One transformers during the 2025-2029 rate period, as Hydro One completes the renewal of these end-of-life assets. The renewal plans are initiated by Hydro One and included in the Needs Assessment. Because of the coordination with renewal work, these investments present the greatest value-for-money in terms of $/MW, and are pursued even when the incremental capacity may not be immediately accessible.[24]

Based on the most recent Needs Assessment, City of Toronto Development Plans, and electrification risks to station capacity adequacy, Toronto Hydro has identified benefits in upgrading transformers at the stations listed in Table 14 below. These upgrades will immediately provide an estimated 226 MW of new capacity to Toronto Hydro's system, and up to another 272 MW of new capacity with further investments. For similar reasons, the Needs Assessment also recommends the upgrade of these units, with the exception of Carlaw TS.[25]

Hydro One will not plan to replace transformers until the units have reached end-of-life, typically after 45 years.[26] It is cost effective for Toronto Hydro to coordinate upgrades with Hydro One's renewal project schedule. Upgrades are only possible by removing and replacing the existing transformer. The cost to remove and replace the existing unit with a higher capacity unit outside of a Hydro One renewal project is approximately $10 million per unit, less asset depreciation. Alternatively, the incremental cost to upgrade a transformer in coordination with its renewal is approximately $0.8 million. Based on the needs identified from the NA and RIP as shown in Table 4 and Table 5, Toronto Hydro foresees the need for additional capacity at each of the stations in Table **14**. Given the long life of these assets and the cost efficiencies achieved by coordinating with Hydro One's renewal schedule, Toronto Hydro has determined that it is prudent to invest in the incremental transformer upgrades listed in Table 14 to ensure that transformation capacity does not become a bottleneck to station capacity over the long term.

[24] Additional investment(s) may be needed following the transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced.
[25] The Carlaw TS T1/T2 transformer renewals are not included the Hydro One NA Report, but their timing for renewal approaches the end of the 2025-2029 CIR rate period. Toronto Hydro proposes to prioritize their replacement and upgrade to support capacity needs identified at the adjacent Basin TS, as noted in the NA and RIP and referenced in Table 5. The East Harbour Master Plan and Port Lands development plans will intensify capacity needs at Basin TS.
[26] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)

Table 14: List of Toronto Hydro Owned Busses Connect to Hydro One Transformer Replacement

Project	Transformer Ratings (MVA)		Immediate New Capacity[27] (MW)	Potential New Capacity[28] (MW)
	Existing	New		
Basin TS – T3/T5 Upgrade	75	100	36	-
Carlaw TS – T1/T2 Upgrade[25]	75	100	54	-
Duplex TS – T1/T2 Upgrade	75	100	-	43
Duplex TS – T3/T4 Upgrade	75	100	-	16
Leslie TS – T1 Upgrade	125	125	-	91
Manby TS – T13/T14 Upgrade	93	125	16	60-122
Scarborough TS – T23 Upgrade	125	125[29]	38	-
Strachan TS – T14 Upgrade	75	100	53	-
Strachan TS – T13/T15 Upgrade	75	100	29	-
Total			**226**	**210-272**

E7.4.4 Expenditure Plan

Spending in the Stations Expansion program over the 2020-2024 rate period was forecasted to be $139.9 million. Toronto Hydro proposes to spend $173.2 million over the 2025-2029 rate period to add 321 MW of new capacity to its system, and contribute to an additional 269 MW of capacity realized in 2030-2034.[30] Forecasted growth, largely driven by City of Toronto Development plans, is driving the need for substantial new capacity to be added to Toronto Hydro's system, resulting in the need for increased expenditures.

[27] New capacity which will be realized following the Hydro One transformer(s) upgrade(s)
[28] Additional investment(s) will be needed following the Hydro One transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced, a new switchyard may need to be installed, or an additional transformer may need to be upgraded.
Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Stations Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear).
[29] Although the Scarborough T23's rating will not change, during the replacement components associated with the unit which limit station capacity will be upgraded, resulting in new capacity.
[30] The Downsview TS and Scarborough TS Expansion projects will contribute 271 MW of new capacity and are forecasted to come in-service during the 2030-2034 rate period.

Table 15: Historical & Forecast Program Costs by Segments ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS Expansion	7.5	35.1	26.5	6.3	4.0	-	-	-	-	-
Hydro One Contributions	10.7	15.2	21.0	11.5	2.1	7.8	4.3	29.6	31.8	29.5
Downsview TS	-	-	-	-	-	3.2	3.9	9.6	25.9	27.7
Total	**18.2**	**50.3**	**47.5**	**17.8**	**6.1**	**11.0**	**8.1**	**39.2**	**57.7**	**57.2**

Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $139.9 million in its Stations Expansion Program, which is a small overspend of $8.2 million or 6 percent relative to the $131.7 million forecasted in the 2020-2024 Distribution System Plan.[31]

This variance is mostly attributable to variances in the Hydro One Contributions segment, with a variance of $7.1 million. The major sources of variances in this segment result from: a Copeland TS Phase 1 True-Up payment, switchyard expansions at Bermondsey TS and Richview TS, Hydro One support for a new supply cable between Carlaw TS and Gerrard TS. Each of these sources is included in the Reactive Hydro One Contribution subsegment, which by its nature is challenging to forecast.

The proposed projects in the Stations Expansion program will address capacity constraints in areas identified by the Hydro One's 2022 Needs Assessment ("NA") Report, and will coordinate with the sustainment plans outlined in the Report. Given the complexity and size of these individual projects, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year.

E7.4.4.1 2020-2024 Variance Analysis – Copeland TS Expansion

Copeland TS Phase 2 expansion work commenced in 2017 and is expected to be completed in 2024. Table 16 below provides the cost summary with Actual and Bridge amounts for Phase 2. Over the

[31] Less the Local Demand Response segment, which has moved to the Non-Wires Alternatives Program, Section E7.2

2020-2024 rate period, Toronto Hydro forecasts to spend $79.5 million on Copeland TS Phase 2, which is which is aligned with the $78.4 million forecasted in the 2020-2024 DSP.

Table 16: 2020-2024 Budget (Actual/Bridge/Forecast) Copeland TS – Phase 2 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS – Phase 2	7.5	35.1	26.5	6.3	4.0	0	0	0	0	0

An engineering, procurement, and construction (EPC) contractor was selected through a competitive bid process in 2020 and the vast majority of the project costs are incurred in the 2020-2024 rate period. Phase 2 of Copeland TS is expected to complete in early 2024, therefore no expansion cost is forecasted for the period of 2025-2029. Table 17 below summarizes the annual spending on Copeland Phase 2.

Table 17: Copeland Phase 2 Annual Budget Comparison ($ Millions)

Year	Initial Budget (EB-2018-0165)	Current
2017	0.5	0.3
2018	1.8	0.2
2019	7.8	3.5
2020	8.9	7.5
2021	29.7	35.1
2022	38.8	26.5
2023	1.0	6.3
2024	0	4.0
Total	**88.5**	**83.4**

Overall, the total project cost is expected to be $5.1 million below the initial total project cost and the contingency portion of the budget is not utilized. Cost savings arise primarily from more efficient execution and labour expenses, better procurement agreements for major equipment, and experience with execution and incorporation of lessons learned from Copeland Phase 1.

The EPC contractor selection took slightly longer and EPC contractor started work in 2020, whereas it was initially planned in 2019. Thus, the entire schedule and spending profile is shifted later by approximately a year. Costs were lower in 2019 due to planned design work by the EPC contractor starting in 2020 rather than 2019.

In mid-2020, the EPC contractor mobilized to site and pre-construction works and evaluation of existing site conditions was completed. By end of 2020, design progressed to 50 percent and procurement operations commenced. Project management and ancillary costs ramped up in 2020 and continued throughout to the end of the project.

In 2021, project spending was $5.4 million higher than initial plan due to completion of the majority of procurement of major electrical assets slightly ahead of plan. In particular, three Medium Voltage (“MV”) Gas-Insulated Switchgears (“GIS”), three MV Air-Insulated Switchgears (“AIS”), High Voltage (“HV”) cable, MV cable, and Protection and Control (“P&C”) control equipment were delivered to site in 2021. Manufacturing was underway for the three Gas-Insulated Transformers (“GIT”) and approximately 47 percent of their costs were incurred by end of 2021. Furthermore, all design was completed (except for 2 percent remaining on mechanical and structural design and a few electrical studies.)

Assembly, installation, testing, and commissioning of the three GIS and three AIS was completed in 2022. In addition, the three GITs were delivered to site from Japan in late 2022. Installation of HV and MV cable, P&C equipment and GITs progressed. Spending in 2022 was $12.3 million lower than initial plan due some procurement work completed earlier in 2021, and electrical equipment construction work continuing into 2023.

Spending in 2023 is $5.3 million higher than initial plan due to construction work continuing into 2023 whereas they were planned to be completed in 2022 in initial version. In particular, assembly, installation, testing, and commissioning of the three GITs and P&C equipment continued into 2023. Energization of major electrical equipment, including all three GITs, will be carried out in 2023.

Full system integration testing will commence near the end of 2023 and continue into 2024. Project closeout, site restoration and final site landscaping works is expected to be completed in early 2024.

2020-2024 Variance Analysis – Hydro One Contributions

Table 18 below provides the 2020-2024 variances for each project requiring Hydro One Contributions, as compared to the 2020-2024 DSP. Toronto Hydro forecasts an overspending of $7.1 million relative to the $53.3 million forecasted in the 2020-2024 DSP.

Table 18: Hydro One Contributions 2020-2024 Variances ($ Millions)

Subsegments	2020-2024 Planned	2020-2024 Actual/Forecast Cost	Variance
Horner Expansion	34.4	29.2	-5.2
Hydro One Transformer Upgrades	3.1	6.3	+3.2
Finch TS B-Y Bus Replacement	4.1	0	-4.1
Reactive Hydro One Contribution and True-Up Costs	11.7	24.9	+13.2
Total	**53.3**	**60.4**	**+7.1**

1. **Horner TS Expansion**

In the 2020-2024 rate application, Toronto Hydro forecasted a $34.4 million capital contribution to Hydro One for the Horner TS expansion based on a Class C estimate provided by Hydro One at the time. The actual costs incurred over 2020-2024 was $29.2 M, but a true-up payment may be required in the 2025-2029 rate period.

2. **Hydro One Transformer Upgrades:**

Over the 2020-2024 rate period, Toronto Hydro forecasts to contribute $6.3 million to Hydro One to upgrade existing Hydro One-owned power transformers. This will result in an overspend of $3.2 million compared to the forecast of $3.1 million in the 2020-2024 rate application. The projects are driven by Hydro One sustainment plans and new customer connections. Major sources of variance are as follows.

- **Carry-over transformer upgrades from the 2015-2019 rate period:** additional $2.7 million for lagging payments or to complete work initially forecasted to be complete by 2019, at Cecil TS, Dufferin TS, and Main TS.

- **Additional transformer upgrades:** additional $1.8 million capital contribution to Hydro One to upgrade transformers at Bridgman TS and Strachan TS, which was not included in the 2020-2024 DSP due to the timing of Hydro One's sustainment plans.
- **Variances to costs of proposed projects:** less $1.5 million capital contribution to Hydro One for planned transformer upgrades at Charles TS, Duplex TS, and Windsor TS. Hydro One is forecasted to charge an additional $1 million for the Charles TS transformers, the Duplex TS transformers have been deferred to the 2025-29 rate period, and Hydro One did not charge to upgrade the transformers at Windsor TS due to downsizing other equipment.

3. Finch TS B-Y Replacement

In the 2020-2024 rate application, Toronto Hydro proposed to replace Finch BY bus in coordination with Hydro One for a contribution of $4.1 million; however, Hydro One deferred the BY replacement to beyond 2025. To address a progressing failure risk, Toronto Hydro decided to replace the end-of-life circuit breakers and disconnect switches on the BY bus instead of waiting for the entire BY bus to be replaced.[32] Therefore, by pursing this alternative through the Stations Renewal Program, this Hydro One Contribution was never made and resulted in a variance of -$4.1 million.

4. Reactive Hydro One Contribution and True-Up Costs:

In the 2020-2024 rate application, Toronto Hydro allocated $11.7 million for reactive Hydro One contributions to support expansion projects or true-up costs unforeseen at the time of the application. Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period for these reasons, resulting in an overspend of $13.2 million.

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $9.9 million to reconcile past Hydro One capital contributions to Copeland TS Phase 1. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance. In particular for this project, $5.7 million was incurred due to reduced station loading, and $4.2 million was incurred due to additional spend by Hydro One relative to their CCRA estimate.[33]

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[32] Please refer to the Stations Renewal Program Section E6.6.4.1 "TS Segment Expenditure Plan", subsection "TS Outdoor Breaker – 2020-2024 Variance Analysis".
[33] Connection Cost Recovery Agreement

Toronto Hydro forecasts to contribute $10.9 million to Hydro One for the following expansion projects which could not be estimated at the time of the previous application.

- **Switchyard expansions at Bermondsey TS and Richview TS:** These projects will expand the switchyards at the respective stations by six and four circuit breakers, permitting new feeders to access stranded station capacity. A forecasted $8.5 million capital contribution is required.
- **New supply cable between Carlaw TS and Gerrard TS:** This project will increase the capacity of Carlaw TS by 20 MVA and resulted in a Hydro One contribution of $2.4 million.

Finally, Toronto Hydro has allocated a remaining $1.9 million in 2024 for additional unforeseen Hydro One Reactive contributions, in the form of cost variances from current forecasts.

E7.4.4.2 2025-2029 Expenditures - Downsview TS

Toronto Hydro forecasts to spend $70.2 million on Downsview TS during the Planning and Preparation stage over the 2025-2029 rate period, and expects to spend another $70 million over the Construction and Energization stage over the 2030-2034 rate period. Downsview TS is expected to complete in late 2033. An annual breakdown of the expenditures is shown below in Table 19.

Table 19: 2025-2029 Budget Downsview TS ($ Millions)

	Forecast – Planning and Preparation					Forecast – Construction & Energization				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Downsview TS	3.2	3.9	9.6	25.9	27.7	30.7	24.0	7.6	7.7	--

1. Downsview TS – Planning and Preparation

The Downsview TS project will be a large and complex project for Toronto Hydro, with only the Copeland TS project being comparable.

The Planning and Preparation stage will involve the portion of work completed in the 2025-2029 rate period, which will involve the: procurement and preparation of a new site, installation of 230 kV station assets, new building construction, and partial work on remaining station assets. The expenditures for this scope are forecasted to total $70.2 million over the period with $14.6 million included in the rate base when civil assets are completed. The remaining forecasted spend is related to electrical assets which will be energized when the station is completed in 2033, and will not be included in the rate base until such time.

There are four major activities to be completed in the 2025-2029 rate period: contractor Request for Proposal ("RFP"), design and engineering, major asset procurement, and construction or installation of some major assets.

A summary of the Downsview TS – Planning and Preparation stage schedule and annual cost is provided below in Table 20: Summary Schedule and Annual Cost of Downsview TS – .

Table 20: Summary Schedule and Annual Cost of Downsview TS – Planning and Preparation

Year	Budget ($ Millions)	Work Schedule
2025	3.2	• Partial Property Acquisition and Site Preparation
2026	3.9	• Completion of Property Acquisition and Site Preparation • Design of 230 kV bus work and disconnect switches
2027	9.6	• Procurement of 230 kV bus work and disconnect switches • Design of 230 kV circuit breakers and procurement • Design of 230 kV underground circuits and supporting civil structures • Design of switchgear building • Procurement of construction equipment and materials for new building
2028	25.9	• Installation of 230 kV bus work and disconnect switches • Partial installation of 230 kV circuit breakers and foundations • Partial construction of civil structures for 230 kV underground circuits • Partial construction of switchgear building • Partial design of power transformers, foundations, fire walls, fire suppression, and oil containment systems

Year	Budget ($ Millions)	Work Schedule
2029	27.7	• Completed installation of 230 kV circuit breakers and foundations • Continued construction of civil structures for 230 kV underground circuits, and partial procurement of 230 kV circuits and protection systems • Completed construction of switchgear building • Completed design for power transformers and supporting assets • Partial procurement of first power transformer • Procurement of materials for power transformer foundations and oil containment systems • Design and partial procurement of 27.6 kV switchgear • Design and partial procurement of station AC, DC, and ancillary services

2. Downsview TS – Construction and Energization

The Construction and Energization stage will involve work completed starting in 2030 until commissioning of the new station in 2033. Work in this stage will involve the: completion of 230 kV underground circuits, installation of power transformers, installation of switchgear, installation of station services, and overall commissioning. The expenditures for this scope are estimated to total $70 million over the period.

A summary of the Downsview TS – Construction and Energization stage schedule and annual cost is provided below in Table 21.

Table 21: Summary Schedule and Annual Cost of Downsview TS Construction and Energization Stage

Year	Budget ($ Millions)	Work Schedule
2030	30.7	• Completed construction of civil structures for 230 kV underground circuits • Completed procurement of 230 kV circuits and protection systems • Partial installation of 230 kV circuits and protection systems

Year	Budget ($ Millions)	Work Schedule
		• Installation of foundations and oil containment systems of power transformers • Partial procurement of first and second power transformers • Delivery of 27.6 kV switchgear • Completed procurement and partial installation of station AC, DC, and ancillary services
2031	24.0	• Completed installation of 230 kV circuits and protection systems • Delivery and installation of first power transformer • Partial procurement of second power transformer • Installation of fire wall between first and second transformer • Partial installation of 27.6 kV switchgear • Completed installation of station AC, DC, and ancillary services
2032	7.6	• Delivery and installation of second power transformer • Completed installation of 27.6 kV switchgear
2033	7.7	• Installation of fire suppression systems for power transformers • Final commissioning of power transformers, 27.6 kV switchgear, and integrated protection systems with Hydro One

E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions

Toronto Hydro forecasts to spend $103.0 million on Hydro One capital contributions over the 2025-2029 rate period. The expenditures include contributions to Hydro One for stations expansions and for transformer upgrades. These projects are planned based on the Needs Assessment (see below at Section 7.4.7 Regional Planning Needs). Additionally, contributions towards the Hydro One-owned Downsview SS are included.

1 **Table 22: 2020-2029 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)**

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Horner TS Expansion	8.5	5.0	15.7	--	--	--	--	--	--	--
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	--	--
Downsview SS	--	--	--	--	--	--	0.6	1.7	2.9	0.6
Scarborough TS Expansion	--	--	--	--	--	--	0.3	17.0	17.0	17.0
Sheppard TS Bus Expansion	--	--	--	--	--	--	0.5	4.5	5.0	5.0
Manby TS DESN Reconfigurations	--	--	--	--	--	--	0.5	3.5	4.0	4.0
Hydro One Transformer Upgrades	1.1	--	2.5	2.5	0.2	4.3	0.4	1.6	1.6	1.6
Reactive Hydro One Contributions & True-Up Costs	1.1	10.1	2.5	9.0	1.9	3.5	2.0	1.3	1.3	1.3
Total	**10.7**	**15.1**	**21.0**	**11.5**	**2.1**	**7.8**	**4.3**	**29.6**	**31.8**	**29.5**

2 **1. <u>Hydro One Switching Station for Downsview TS</u>**

3 Based on high level estimates from Hydro One, Toronto Hydro forecasts to contribute $5.8 million
4 over the 2025-2029 rate period to Hydro One as an initial contribution towards Hydro One's
5 Downsview Switching Station ("Downsview SS"). Downsview SS is expected to be largely constructed
6 during the 2030-2034 period. As a result, Toronto Hydro is only forecasting expenses over the 2025-
7 2029 rate period to be associated with the procurement of land for and the site preparation of the
8 new SS.

9 **Table 23: Downsview TS Expansion Hydro One Payment Breakdown**

Project	Expenditures ($ Millions)	Payment Year
Downsview SS	0.0	2025
	0.6	2026
	1.7	2027
	2.9	2028
	0.6	2029

2. Scarborough TS Expansion

In order to install a new DESN at Scarborough TS, Toronto Hydro forecasts to contribute $51.3 million to Hydro One over the 2025-2029 rate period. Toronto Hydro estimates the project to be completed in 2030, and therefore forecasts and additional contribution of $5.0 million in 2030. As a result, none of the 2025-2029 spending will be included in the rate base until the project is completed in 2030. In total, Toronto Hydro forecasts the project to cost $56.3 million in capital contributions. The forecasted annual expenditures are provided in Table 24 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this Filing. However, from the high-level perspective, the scope of work of this project is the same as the Horner TS expansion completed during the 2020-2024 rate period, less half of its switchyard[34]. As a result, Toronto Hydro has forecasted the expenditures of this project based off of the actual expenditures of the Horner TS expansion project, less the estimated costs for half of the switchyard.

The scope of work involved for this project includes: the clearing of land and site preparation for the new DESN, the installation of new transmission taps and high voltage disconnect switches, the installation of two new 125 MVA transformers, the installation of a new 95 MW switchyard with six circuit breakers, and the installation of a new P&C building.

Table 24: Scarborough TS Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Scarborough TS Expansion	0	2025
	0.3	2026
	17.0	2027
	17.0	2028
	17.0	2029
	5.0	2030

[34] The Horner TS expansion provided 12 new circuit breakers, whereas the Scarborough TS expansion proposes 6 new circuit breakers. The assets upstream of the circuit breakers (such as transformers) are proposed to be the same for both projects.

3. Sheppard TS Bus Expansion

In order to install a new bus at Sheppard TS, Toronto Hydro forecasts to contribute $15.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 25 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this filing. However, Toronto Hydro has estimated expenditures based on the scope of work, which is similar to its TS switchgear installations from its Stations Renewal Program and from its Copeland Phase 1 and Phase 2 expansion projects.

The scope of work includes the installation of a new gas-insulated switchgear (GIS) comprised of six feeder circuit breakers, three padmounted feeder-tie disconnect switches, P&C devices, and a new building to house the GIS and P&C devices.

Table 25: Sheppard TS Bus Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Sheppard TS Bus Expansion	0	2025
	0.5	2026
	4.5	2027
	5.0	2028
	5.0	2029

4. Manby TS DESN Reconfigurations

In order to replace two Jones switchyards with one Bermondsey switchyard at Manby TS, for both capacity and renewal benefits, Toronto Hydro forecasts to contribute $12.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 26 below.

This project is still in its planning phase with Hydro One, due to the need to coordinate with and adapt Hydro One’s existing T13/T14 transformer upgrade plans, which they have proposed for 2030. Because the T13/T14 upgrade is planned to take place seven years into the future from the time of this filing, Hydro One has not been able to develop a scope of work at this time. Similarly, Hydro One also has not been able to provide Toronto Hydro with a cost estimate at the time of this filing.

As a result, Toronto Hydro has estimated the scope of work involved, and has used this to estimate the needed Hydro One contributions. Consequently, there is more uncertainty in this expenditure forecast compared to the other projects proposed in this Program.

However, Toronto Hydro will need to provide its capital contribution to Hydro One during the 2025-2029 rate period, and that the capital contribution for this project will be too substantial to be managed by the Reactive Hydro One Contributions subsegment. Therefore, Toronto Hydro has elected to budget for this project separately, and has produced the best expenditure forecast it can with the information available at this time.

Table 26: Manby TS DESN Reconfigurations Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Manby TS DESN Reconfigurations	0	2025
	0.5	2026
	3.5	2027
	4.0	2028
	4.0	2029

5. Hydro One Transformer Upgrades

Toronto Hydro forecasts to contribute $9.5 million to Hydro One over the 2025-2029 rate period, in order to upgrade certain end-of-life transformers during their natural renewal projects. Table 27 below outlines the contributions to Hydro One by project, and the year the contribution is expected to be made.

The cost for each project was forecasted based on the actual costs of transformer upgrade projects completed or in-progress over the 2020-2024 rate period. The timing of each project has been provided in the NA assessment, which has been used to forecast when each capital contribution will be required, based on historical timing trends.

Table 27: Hydro One Transformer Upgrades Payment Breakdown

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Basin TS – T3/T5	1.6	2025
Carlaw TS – T1/T2	1.6	2029
Duplex TS – T1/T2	1.6	2025

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Duplex TS – T3/T4	1.6	2028
Leslie TS – T1	0.3	2025
Scarborough TS – T23	0.4	2026
Strachan TS – T14	0.8	2025
Strachan TS – T13/T15	1.6	2027

6. Reactive Hydro One Contributions

As noted in Section 0, **2020-2024 Variance Analysis – Hydro One Contributions**, Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period towards Reactive Hydro One Contributions. This subsegment was first introduced during the 2020-2024 CIR based on previous experience of funding shortfalls as new, unbudgeted, Hydro One projects were initiated, or as unexpected Hydro One true-up costs were billed to Toronto Hydro. Examples of such Hydro One projects include transformer or cables upgrades, or the installation of new circuit breakers, which result in an incremental increase in capacity.

As predicted, there were indeed significant unexpected projects and true-up costs which developed during the 2020-2024 rate period, and the Reactive Hydro One Contributions subsegment is forecasted to mitigate (approximately half of) the unexpected spending in the Hydro One Contributions segment, as intended. Therefore, Toronto Hydro proposes this subsegment continue into the 2025-2029 rate period, as a continued mitigation measure since it again anticipates a need in the 2025-2029 rate period.

To this end, Toronto Hydro has allocated $9.4 million over the 2025-2029 rate period towards Reactive Hydro One Contributions. The annual expenditures are provided in Table 28 below.

Table 28 : Reactive Hydro One Contributions Annual Allocations

Subsegment	Expenditures ($ Millions)	Payment Year
Reactive Hydro One Contributions	3.5	2025
	2.0	2026
	1.3	2027
	1.3	2028
	1.3	2029

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options to address system needs, as outlined in the below sections.

E7.4.5.1 Options Comparison for the Downsview Area

To address the forecasted need for additional capacity in the Downsview area, Toronto Hydro considered several options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and a new Downsview TS. The key results of the Options studied are summarized in Table 29. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 6 – building the new Downsview TS is the only option capable of meeting system needs with reasonable risks and quantity of load transfers. See Exhibit 2B, Section E7.4, Appendix A – Downsview Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. Status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.
- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2029.
- **Option 3 – NWSs** was rejected because it would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 193 MW).[35]
- **Option 4 – Station Upgrades** was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically infeasible and was rejected.

[35] See E7.2.1.4

- **Option 5 – New DESN(s)** was considered for each of the four existing stations within the Downsview Area; but only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this Option is forecasted to require a high quantity of load transfers, specifically 290 MW by 2044, to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by Option 5, this Option was ultimately rejected.

- **Option 6 – Construction of Downsview TS** is the selected option. Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. The construction of a new TS is a large and complex undertaking. Therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous Option 5 at 252 MW. Option 6 also includes a provision to address the risk of subsequent overloading in the long term by permitting a second DESN to be installed at the newly constructed TS, whereas no provision exists in Option 5.

1 **Table 29: Summary of Options Outcomes for the Downsview Area**

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2044 or Earlier] (MW)[36]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option only provides a short-term solution.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	193	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	290	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	252	Minimal	Medium	Mitigated

2

[36] Load relief (as load transfers or NWAs) required past 2044 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2044, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

E7.4.5.2 Options Comparison for the Scarborough Area

To address the forecasted need for additional capacity in the Scarborough Area, Toronto Hydro considered several options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and a new TS. The key results of the Options studied are summarized in Table 30. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 5 – constructing a new DESN at Scarborough TS is the option capable of meeting system needs with the least cost and risk. See Exhibit 2B, Section E7.4, Appendix B – Scarborough TS Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. The status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.
- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2029.
- **Option 3 – NWSs** were rejected because they would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 179 MW).[37]
- **Option 4 – Station Upgrades** were also rejected as they are only viable up until 2030.
- **Option 5 – New DESN(s)** considered constructing a new DESN at either Scarborough TS or Warden TS, in addition to investing in a transformer upgrade at Scarborough TS which was considered in Option 4. This Option will address capacity needs into the long term, and has a substantially lower cost and risks compared to Option 6. Therefore, this Option was selected as the preferred Option.
- **Option 6 considered constructing a new TS** in the Scarborough Area to provide new capacity. However, this Option provides the same quantity of capacity as Option 6, but requires a

[37] see E7.2.1.4

much higher cost, and a much higher execution risk and lead time. As a result, Option 6 was rejected.

Due to the challenges in geography in expanding Warden TS and increased reliability risks, Toronto Hydro selected Scarborough TS as the station to expand at this time.

1 **Table 30: Summary of Options Outcomes for Scarborough Area**

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2039 or Earlier] (MW)[38]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term interim solution while a long term solution is in progress.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	179	High	Very High	Mitigated
4 – Station Upgrades	Reject	This Option can only manage loading until 2030.	No	30	Minimal	Minimal	Forecasted Overload
5 – New DESN(s)	**Accept**	Meets system needs with reasonable risks and quantity of load transfers.	Yes	63	Minimal	Medium	Mitigated
6 – New TS	Reject	This Option carries excessive costs, lead time, and risks in comparison to Option 5.	Yes	68	Minimal	High	Mitigated

2

[38] Load relief (as load transfers or NWAs) required past 2039 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2036, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

E7.4.5.3 Options for the Sheppard Area

In addition to the proposed option to address needs in the Sheppard TS Area, to install a new bus at Sheppard TS, two alternative options were considered: load transfers, and non-wires alternatives (NWAs). Although the proposed option is the most expensive in the short term, it provides additional benefits that the alternatives cannot realize, as summarized in

Table 31 below. Most critically, the proposed option is the only option which also provides new short circuit capacity to enable new DERs at the constrained Sheppard TS.

To keep consistent with the E7.2 Non-Wires Alternatives Program, the same high-level unit cost for load transfers is provided in

Table 31. However, as discussed in E7.4.3 Drivers and Need, it is very challenging to practically address short circuit capacity constraints through load transfers, which is why this option has not been traditionally utilized at present. In practise, the cost to complete such load transfers is expected to exceed the high-level unit cost provided, which was based on projects completed to relieve thermal capacity constraints.

Additionally, upon consideration of the FES, Toronto Hydro has reason to believe that the Sheppard TS bus expansion may in fact be the lowest-cost option in the long term. This is because, when using the provided high-level unit cost, the load transfer option results in an equal cost when a cumulative 50 MW of load has been transferred away from Sheppard TS. Five of the six FES project that this cumulative amount of load will have been transferred by 2033-2039, depending on the scenario.

In contrast to load transfers, Non-Wire Solutions (“NWS”) can also be considered as an alternative to the proposed option. However, unlike load transfers, NWSs bear an annual cost, and therefore are best used as a short-term solution. In particular, for the same quantity of MW addressed, the cost of the NWSs solution becomes equal to the load transfer solution after 4 years have passed, based on the high-level unit cost provided. Therefore, in the long term, the NWSs option is expected to be even more expensive than the load transfer option.

In summary, for the reasons of the additional benefits (particularly to enable new DER connections), and because of the expectation to be the lowest cost option in the long term, the Sheppard TS bus expansion was selected as the preferred option.

Table 31: Benefits Presented by Options to Address Sheppard Area Needs

Benefit or Cost	Sheppard TS Bus Expansion	Load Transfers	NWAs
New Thermal Capacity (MW)	95	0	0
New Short Circuit Capacity (MVA)	126	0	0
Can Provide Support to Scarborough Area?	Yes	No	No
Cost ($M)[39]	15.0	0.3/MW	0.075/ MW-year

E7.4.5.4 Options for the Manby TS Area

The proposed Manby TS DESN reconfigurations project is being triggered by Hydro One's planned renewal and upgrade of its T13/T14 transformers as stated in the Needs Assessment, and by the upcoming need to renew the T3/T4 switchyard. As a result, there are only two options to consider are to either take advantage of the renewal opportunity to improve the station (as proposed), or to dismiss this opportunity.

For similar financial reasons as discussed with the Hydro One Transformer Upgrades subsegment in E7.4.3 Drivers and Need, if Toronto Hydro does not take the opportunity to improve the station during the upcoming renewal work, it will likely have to wait another 45 years before it has another opportunity to complete the proposed improvements or undertake upgrades at a significantly higher cost.

As discussed in the Manby TS DESN Reconfigurations subsection of E7.4.3 Drivers and Need, the proposed option has multiple short term and long-term benefits, related to capacity, reliability, and the execution of the renewal of Manby TS. Ultimately, this option will permit up to 139 MW of new capacity to be added in the long term. These benefits will be lost if the proposed DESN reconfigurations do not proceed.

Upon consideration of the FES, Toronto Hydro believes it is prudent to enable options to increase the capacity of Manby TS in the long term. Four of the six FES project that the Area will require additional capacity between 2035-2039. With the Horner TS expansion complete in the 2020-2024

[39] High-level unit cost estimates for load transfers and NWAs were taken to be consistent with those presented in E7.2 Non-Wires Alternatives Program

rate period, there are presently no expansion options available in the Area other than the installation of a new TS, which was considered as the alternative to the Horner TS expansion.

To align with an investment philosophy of a least-regrets approach, Toronto Hydro should not dismiss the limited-time opportunity to enable Manby TS to be expanded in the future, when needed. In order to do this, Toronto Hydro must invest in the proposed Manby TS DESN reconfigurations project in coordination with Hydro One's T13/T14 transformer renewal project.

For this reason, and because of the other benefits discussed in E7.4.3 Drivers and Need, the proposed option was selected over the alternatives.

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Downsview TS

The Downsview TS segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- New Downsview TS site location and land purchase;
- Road moratoriums established by the City of Toronto;
- 230 kV U/G cable design and construction and Hydro One 230kV switching station design and construction – potential timeline issues;
- Engage Hydro One 230kV Switching Station Design and Construction;
- Logistical challenges in delivering electrical equipment into the city; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Downsview TS bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues. Coordination with Hydro One for switching station construction, the city new TS land and association on the new 230kV route will be the risks on the new TS's construction timeline.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2026.

Quality control risks will be mitigated via the use of reputable third-party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution project:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) may be identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.7 Regional Planning Needs

The following Table 32, Table 33, and Table 34 (from the IRRP Needs Assessment Report), highlight the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[40] The tables below also highlight how the Stations Expansion program is expected to address these needs.

[40] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

1 **Table 32: New Needs Identified in the Needs Assessment**

New Needs	Needs Assessment Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1*	See E7.4.3.2, Section 2. – Hydro One Transformer Upgrades.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.4*	Needs Assessment identified this need by long term planning, short term by replacing T3/5 with 100 MVA.

2 **Table 33: Needs Identified in Previous RIP**

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	7.2.1	7.2	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	7.2.2	7.3	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	7.2.5	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
Voltage Instability of 115 kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	4.2.7	7.10	Transmission network constraint. Not applicable to Toronto Hydro.

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
115 kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.

Table 34: End-of-Life Assets – Metro Toronto Region

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of Needs Assessment).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of Needs Assessment	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of Needs Assessment.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of Needs Assessment for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of Needs Assessment.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E7.4.8 Flexibility Considerations

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there are a large range of outcomes from the energy transition which could impact Toronto Hydro's distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario (NZ40 – Low) projects an unprecedented increase in system load which would translate into a significant level of additional investment for the Stations Expansion Program in order to meet such need.

1 Table 35 shows the estimated costs under this scenario.[41]

2 **Table 35: Estimated Stations Expansion Investment**
3 **Needed under Future Energy Scenarios NZ40-Low Efficiency Scenario**

CIR Period	Estimated Investment Need ($M)[42]
2025-2029	44
2030-2034	186
2035-2039	527

[41] See Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview and Appendix B – Future Energy Scenarios Report.
[42] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects. No expenditures have been forecasted in this Program for 2035-2029. No inflation assumptions have been included.

Downsview TS Business Case

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1 EXECUTIVE SUMMARY

Project Name	Costs	
Downsview TS	$	192.2 M

This project will address forecasted capacity constraints in the Northwest portion of the City due to confirmed large customer requests, the Downsview Area Secondary Plan, and electrification.

The proposed solution is to install a new TS, Downsview TS, in the Downsview Area, roughly between Bathurst TS and Finch TS. This location will permit the new TS to supply the new developments arising from the Downsview Area Secondary Plan, as well as offload the heavily loaded Bathurst, Fairbank, and Finch TSs.

The scope of work involves procuring new land for the new station, and constructing new 230 kV underground cables and duct banks from a Hydro One station, a new building, two new transformers, and one new switchgear. Downsview TS will provide 174 MW of new capacity to supply the Area.

The project is expected to start in Q1 2025 with an in-service date set to Q4 2033. Given the long lead time required to construct a new station, the project will be completed over two stages – Planning and Preparation during 2025-2029 and Construction and Energization over 2030-2034.

The project cost is estimated to be $76.0 million over the 2025-2029 rate period and $116.2 million over the 2030-2034 rate period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost are planned to be capitalized in the 2025-2029 rate period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area is shown in Figure 1. This area will be called the “Downsview Area” throughout the rest of this document.

In recent years, the Downsview Area has been attracting a large quantity of new load, a trend that is forecasted to persist into the future. On average, the Downsview Area is forecasted to grow by 2.1% per annum.

Table 1 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS. However, the station remains highly loaded, and will require further offloading to adjacent stations.

Finch TS is the next highest loaded station. The station is forecasted to reach capacity in 2025, but is forecasted to be loaded just below its capacity as early as 2024, due to large customer connections in-progress. At this point in 2024, the station will not be able to accommodate new connection requests without first initiating load relief projects.

Some capacity remains at Bathurst TS, but not enough to relieve overloading. Fairchild TS remains the only station with significant capacity in the Downsview Area, however it cannot provide direct relief to the highly loaded Fairbank and Finch TSs due to geography.

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2031. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

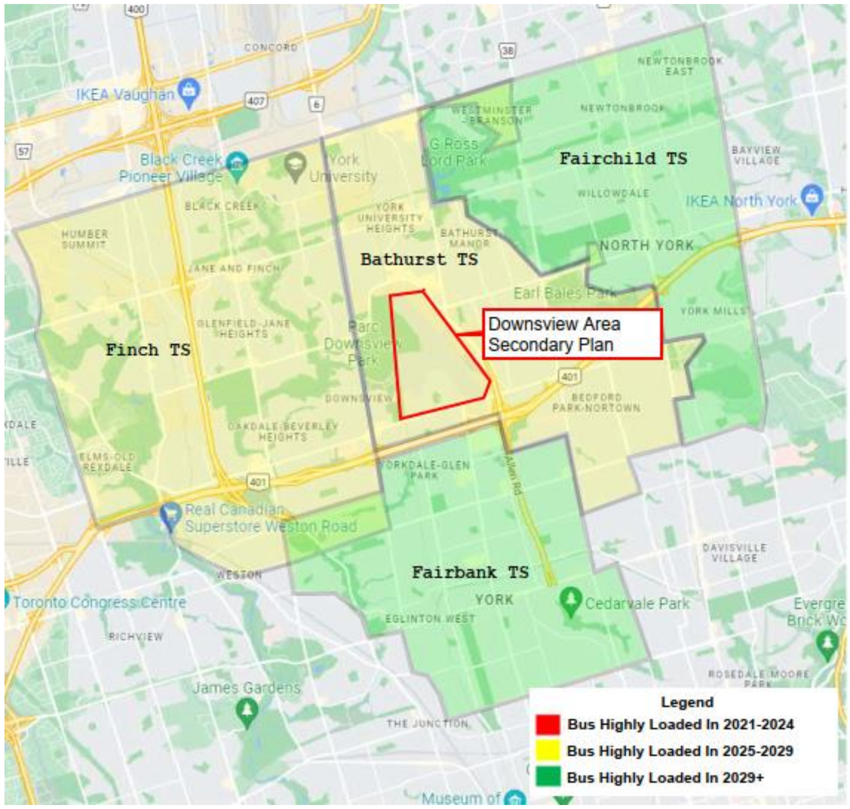


Figure 1 – Map of the Downsview Area and its Stations

Table 1 – Non-Coincident Downsview Area 10-Yr Load Forecast[1]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	73%	78%	79%	85%	86%	86%	85%	85%	85%	85%	85%
Fairbank TS	182	**104%**	**104%**	**94%**	**93%**	**95%**	**97%**	**97%**	**98%**	**100%**	**101%**	**103%**
Fairchild TS	346	61%	67%	67%	69%	69%	69%	70%	70%	70%	71%	71%
Finch TS	366	69%	77%	**90%**	**98%**	**100%**	**102%**	**102%**	**103%**	**104%**	**105%**	**107%**
Area Non-Coincident %	**1255**	**73%**	**78%**	**81%**	**85%**	**86%**	**88%**	**88%**	**88%**	**89%**	**89%**	**90%**

2.2 Downsview Area Secondary Plan

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan ("DASP"). The area is generally bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2.

The DASP plans to expand each district with a mix of commercial, office, industrial and institutional buildings. Mid-rise buildings (10-14 storeys) will be built around the existing TTC Downsview station and lower mid-rise buildings (6-10 storeys). The Allen East District will be primarily be a residential area of 3,500 dwelling units.

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in Table 1. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

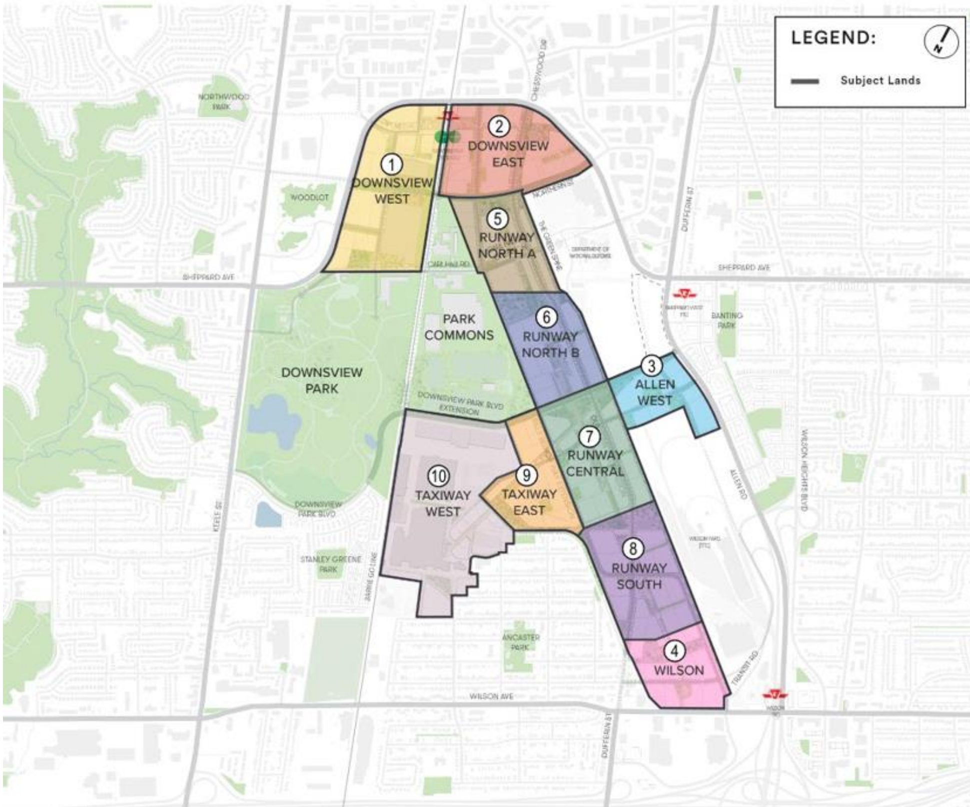


Figure 2 – Downsview Area Secondary Plan Map

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating the anticipated load and generation growth in the City of Toronto. For the City of Toronto to achieve its TransformTO Net Zero Strategy targets, Toronto Hydro is anticipating the overall area load will grow by 40-70% over the next 20 years, largely due to the electrification of heating and transportation. As this transition occurs, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system, nor to existing customers looking to decarbonize.

Additionally, two existing large customers in the Downsview Area have approached Toronto Hydro to inquire about expanding their load by an additional 85 MW by 2030. These inquires have not been explicitly included in any forecasts. Although not yet firm requests, such inquiries corroborate the potential for the rapid load growth needed to achieve the TransformTO Net Zero Strategy targets, and the demand for capacity in the area.

Given the current highly-loaded state of the Downsview Area, the addition of the approved DASP, and the likelihood of rapid electrification underway, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments.

Options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner. Load relief plans for the Downsview Area should also consider the potential for future load growth, to ensure that investments are chosen to be cost-effective in the long term.

3 DOWNSVIEW AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Downsview Load

The Peak Demand Forecast only extends to 2031; however, as an additional approach to the sensitivity analysis, we will assume that the total Downsview Area load growth past 2031 is provided exclusively by the DASP. The NA forecast already includes consideration for the DASP up until 2031.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the Downsview Area Secondary plan. The annual load growth from this forecast over 2032-2051 was first adjusted to 70%[2], and then added to the 2031 station loads from the Peak Demand Forecast. The results are provided in Table 2, and referred to as the "25 Year Forecast" hereafter.

Table 2 - Estimated Station Loads under the 25 Year Forecast

STATION	Summer LTR (MW)	2021 (Actuals)	2024	2029	2034	2039	Year 100% Capacity is Reached
Bathurst TS	361	67%	78%	83%	90%	**98%**	2040
Fairbank TS	182	**104%**	**93%**	**104%**	**115%**	**124%**	2029
Fairchild TS	346	61%	69%	71%	71%	71%	N/A
Finch TS	366	69%	**98%**	**106%**	**113%**	**117%**	2025
Area Non-Coincident %	**1255**	**71%**	**84%**	**90%**	**95%**	**100%**	2039

This forecast shows that by 2039 the Downsview Area as a whole will reach capacity, with substantial load growth continuing past then. Prior to that, significant overloading is forecasted at Fairbank TS and Finch TS, which cannot be directly relieved by Fairchild TS, the only station with capacity, due to geography. The 25 Year Forecast indicates that regional capacity constraints will persist past the medium term, and worsen further into the long term.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

[2] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Across the six modelled Future Energy Scenarios, Toronto Hydro expects that all but one station will become heavily loaded by 2035, and that the area as a whole will become overloaded between 2030 and 2037. Table 3 provides the station and area loading under the Future Energy Scenarios, and Figure 3 illustrates the area non-coincident loading under the Future Energy Scenarios. The Future Energy Scenarios do not specifically consider the DASP.

Table 3 – Non-Coincident Downsview Area Loading under Future Energy Scenarios

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[3]
Bathurst TS	361	67%	78-80%	82-89%	89-**101%**	95-**114%**	2034-N/A
Fairbank TS	182	**108%**	**114-117%**	**117-127%**	**124-142%**	**130-167%**	2021
Fairchild TS	346	62%	65-66%	67-72%	69-78%	70-84%	N/A
Finch TS	366	69%	**102-103%**	**109-116%**	**118-133%**	**124-150%**	2024
Area Non-Coincident %	**1255**	**72%**	**86-88%**	**91-98%**	**97-109%**	**102-122%**	2030-2037

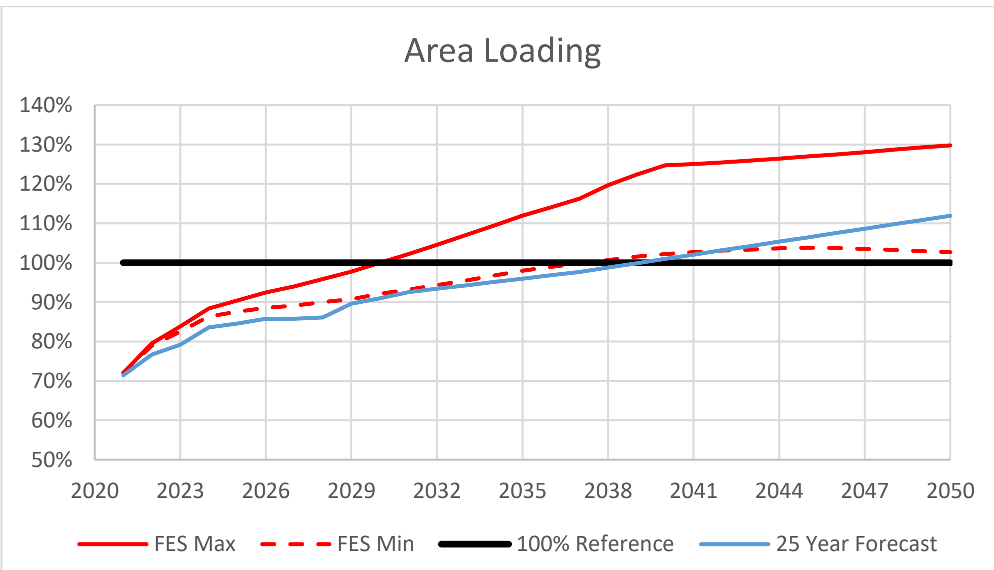


Figure 3 - Non-Coincident Downsview Area 20-Yr Loading from the Future Energy Scenarios Projections

3.3 Sensitivity Conclusions

Two approaches were considered to respectively assess loading impacts to the Downsview Area based on electrification, and the DASP. In both approaches, the Downsview Area is forecasted to be highly loaded by the end of the 2025-2029 rate period. This is marked by overall Downsview Area loading reaching 90% or higher by 2029.

[3] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

4 OPTIONS CONSIDERED

To address the needs of the Downsview Area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Downsview Area at or below 100%. Specifically, this Option assumes that load transfers will be completed just as each station reaches 100% loading, and only to the extent to keep the station at 100% loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Peak Demand Forecast in Table 1 in Section 2.1, the Downsview Area will not reach 100% loading over 2024-31, and therefore this option is possible. However, this option also presents large operational and reliability risks. Risks rapidly increase past 2029, when at least two stations are forecasted to be overloaded.

As a minimum consequence, the Peak Demand Forecast predicts the Downsview Area will become highly loaded by 2031, and the 25 Year Forecast forecasts this to occur at 2029. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers.

The cumulative load transfers needed according to the 25 Year Forecast is shown in Figure 4, and increases by approximately 17 MW annually starting in 2029. In total, 194 MW in load transfers would be needed over 2029-2039. After 2039, the Downsview Area is forecasted to be overloaded, and this option is no longer feasible.

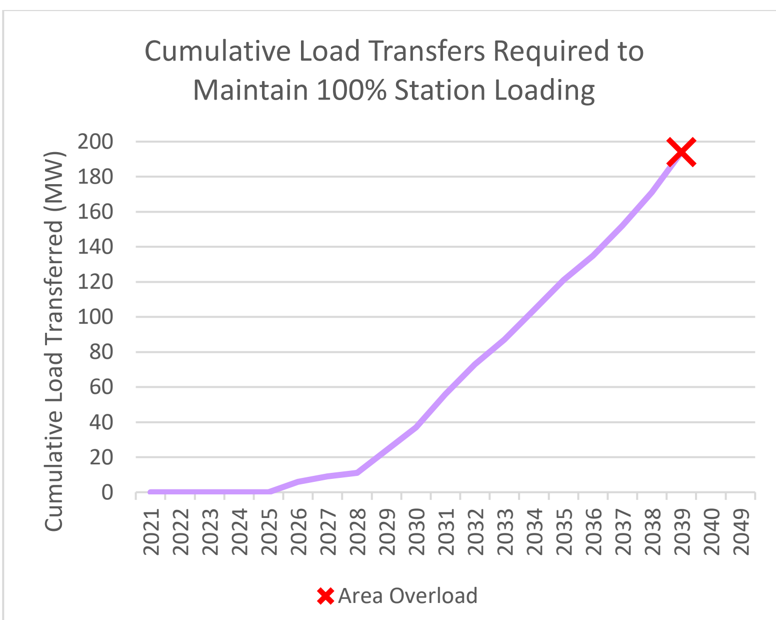


Figure 4 – Cumulative Load Transfers Required Over Time

The FES projections predict a much more rapid load growth, and by contrast load transfers would be needed over the 2024-2037 period. The FES projections predict that the Downsview Area will become overloaded by 2030-2037.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risk involved in running stations at 100% load. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focused" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a station with capacity located further away. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines.

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[4] to avoid damaging the remaining assets. Consequently, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term, interim solution.

In conclusion, this option is not a feasible solution. It requires a high level of risk to be maintained and managed for an unacceptably long period. Into 2039 and past 2039, this option cannot be implemented at all since the entire Downsview Area will reach 100% loading.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once at the start of each 5-year rate application period, to maintain station loading throughout the Downsview Area at or below 90% over the period. This is done while regional capacity remains, in order to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

The Peak Demand Forecast provided in Table 1 in Section 2, shows that the Downsview Area reaches 90% loading in 2031, and each FES Outlook estimates that the Downsview Area will exceed 90% loading by 2029. Therefore, this Option is only considered feasible up to 2029, with risk that this option may become infeasible even earlier than 2029. An estimated 149 MW in load transfers would be required over 2024-2029 under this Option.

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2029. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

[4] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load below its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

4.3 Option 3: Non-Wires Solutions

This Option considers the possibility of addressing high loading and overloading within the Downsview Area using Non-Wires Solutions (”NWSs”), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response (“LDR”).

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro’s distribution system. According to the 25 Year Forecast, 193 MW of LDR capacity would be needed by 2044 in order to maintain the Downsview Area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution.

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered a short-to-medium term solution.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

This option considers the possibility of expanding the capacity of existing DESNs in the Downsview Area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

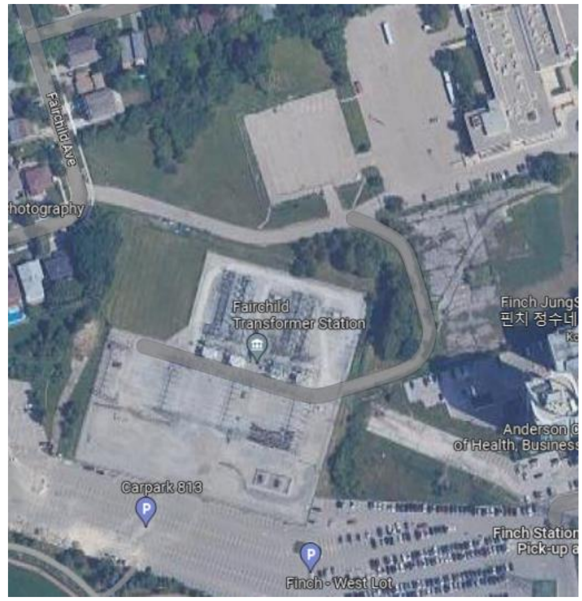
All stations in the Downsview Area are already sized to their maximum ratings. Therefore, this option is not feasible.

4.5 Option 5: New DESN(s)

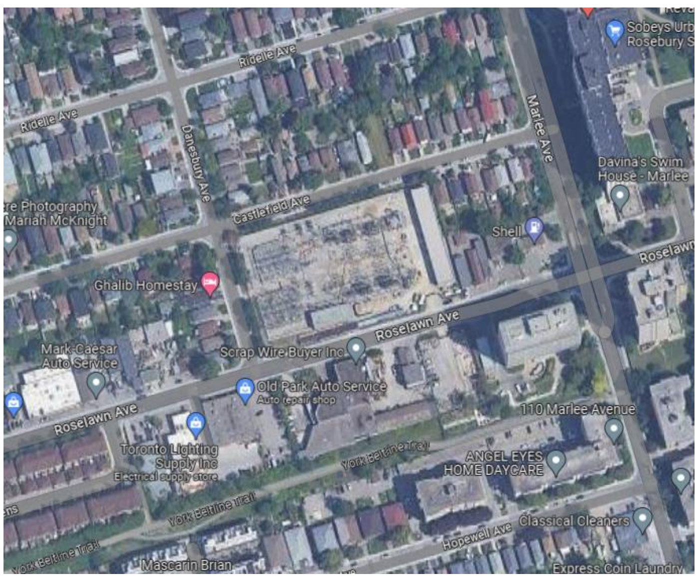
This option considers adding one or more new DESNs at the existing stations in the Downsview Area, referred to as “station expansion”. A typical DESN provides 174 MW of new capacity and supplies 12 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connection costs required of a new station.

Of the four existing stations in the Downsview Area, only two have space surrounding the station which may potentially be considered for station expansion: Fairchild TS, and Finch TS. Bathurst TS and Fairbank TS are located in urban neighborhoods, surrounded by residential and small commercial buildings where expansion would not be feasible. Aerial views of the existing stations are provided in Figure 5 below.

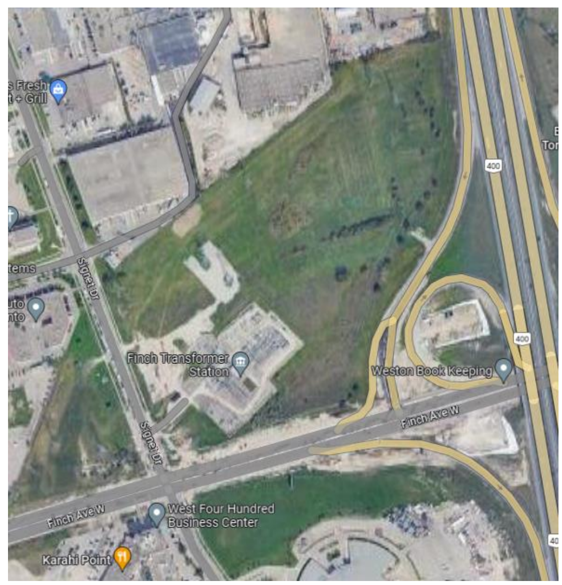
Bathurst TS



Fairchild TS



Fairbank TS



Finch TS

Figure 5 – Aerial Overview of Existing Stations in the Downsview Area

Although some space may be available at Fairchild TS, expansion of this station is not well suited to meet the needs of the Downsview Area. First, the existing spare land would likely be insufficient to install a new DESN, and likely new land would need to be procured towards its north, east, or south, which presents feasibility challenges. Those challenges aside, the location of Fairchild TS is also far from Fairbank TS and Finch TS which need load relief, as can be seen in Figure 1 in Section 2. As a result, load relief would have to be achieved by cascading load transfers through Bathurst TS. Similarly, Fairchild TS is also located away from the DASP area, making it challenging to connect the new loads to new capacity which would be installed at Fairchild TS. Finally, Fairchild TS already supplies two DESN and egresses 24 feeders. Egressing another 12 feeders effectively from the same location would present a significant design challenge.

Finch TS has better land availability, and could likely accommodate another DESN, although it faces significant implementation challenges to be discussed later. Additionally, referring back to Figure 1 in Section 2, Finch TS could provide meaningful load relief to Bathurst TS, but not to Fairbank TS. Therefore, cascading load transfers[5] from Fairbank TS through Bathurst TS to Finch TS, would be needed to ultimately relieve Fairbank TS. This will ultimately magnify load transfer needs, discussed later and illustrated in Figure 8, reducing the efficacy of this option.

As a result of the above considerations, the expansion of Finch TS is the only technically feasible expansion option to consider, although it faces significant challenges in utilizing its new capacity. Therefore, the remainder of this option considers the impacts of an expansion only at Finch TS, and the risks involved.

Given a new DESN at Finch TS, Downsview Area loading is shown at 5-year intervals in Figure 6. Despite the addition of the new DESN, the 25 Year Forecast estimates that the Downsview Area loading will reach 90% again by 2041. FES projections show that there is risk of Downsview Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. However, the new DESN is expected to resolve Downsview Area loading issues in the long term.

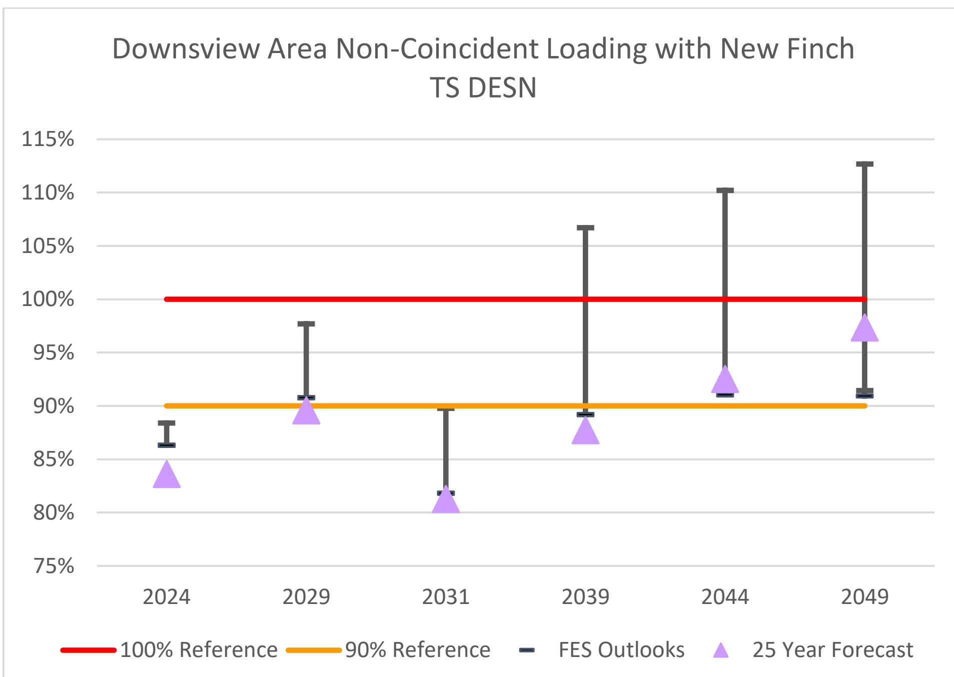


Figure 6 – Downsview Area Loading with a New DESN at Finch TS

The scope of work involved is assumed to be completed entirely by Hydro One, with Hydro One owning all new assets. This is the standard for new Hydro One DESNs, which involve gas-insulated switchgear. Based on a similar expansion completed at Horner TS in 2022, the total cost in Hydro One Contributions is estimated to be $119 million with a project timeline of 6 years. The in-service date would therefore be Q1 2031. The annual estimated Hydro One Contributions are provided in Figure 7.

[5] Cascading load transfer: When one station (“A”) cannot directly offload to a neighbouring station (“B”) with capacity, the station (“A”) must instead first offload to an intermediate station (“C”). Following this, the intermediate station (“C”) must transfer the same quantity of load to station (“B”) which has the available capacity. Ultimately, station (“A”) is offloaded by some amount, station (“B”) increases in load by the same amount, and station (“C”) experiences no change in load. This is process is called a cascading load transfer.

Because the Peak Demand Forecast forecasts stations loading past 90% before the new DESN at Finch TS will be ready, this option assumes the load transfers presented in option 2 will be completed to manage station loading in the meantime. Once the DESN is ready in 2031, load transfers will again be needed to offload the existing stations onto the new DESN. Finally, although the new DESN will introduce capacity into the Downsview Area, it will not be situated to supply all new DASP load. As a result, load transfers will be needed again from 2035 onward in order to relieve Bathurst TS and/or Fairbank TS as they supply new DASP load. In total, 290 MW in load transfers are expected by 2044. The expected load transfers in 5-year increments are shown in Figure 8.

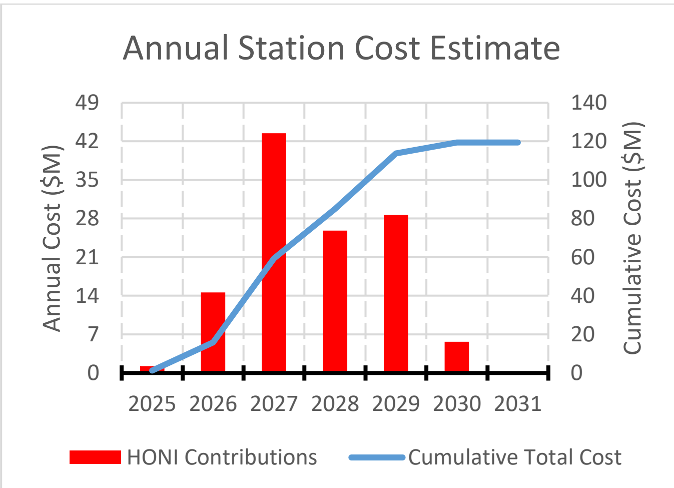


Figure 7 – Estimated Annual Hydro One Contributions for a new DESN at Finch TS

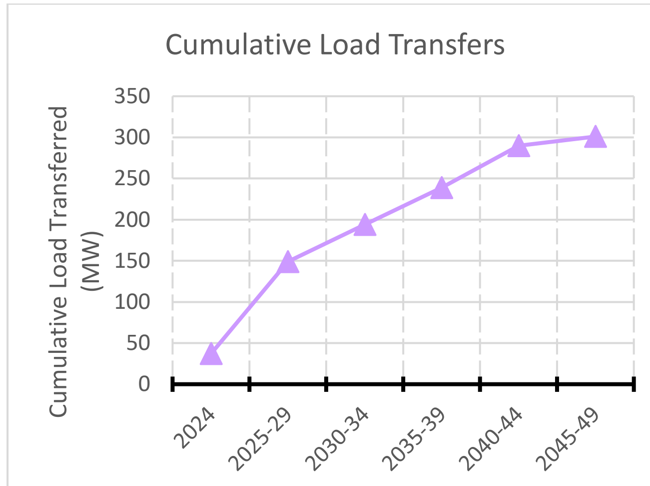


Figure 8 – Cumulative Load Transfers Required for a new DESN at Finch TS

As an exercise intended to quantify the magnitude of load transfers needed, the above load transfer analysis does not consider the significant implementation challenges which are discussed below. Nonetheless, the analysis and Figure 8 show that an unprecedented load of 290 MW will need to be transferred over 20 years in order to make effective use of the new capacity installed in this option. Such a large level of needed load transfer to effectively utilize new capacity signals that the new capacity has been added in the wrong location within the Downsview Area.

In addition to the large magnitude of load transfers needed, a solution at Finch TS would encounter several significant implementation challenges which jeopardize the success of this option in the long term. First, Finch TS already supplies two DESNs and would face similar egressing challenges as Fairchild TS. Second, the DASP area is at the limit of the reach of Finch TS. Given the magnitude of the load expected from the DASP and the distance, reliability and voltage drop concerns would prevent Finch TS from supplying the entire DASP load. Finally, the geographical barriers of Highway 400 and the linear parks that already divide the Finch TS and Bathurst TS service territories would limit the number of feeders that could be extended from Finch TS eastward, effectively bottlenecking new capacity. These geographical barriers are shown in Figure 9**Error! Reference source not found.** and Figure 10**Error! Reference source not found.**.

Figure 9 – Potential Location for New DESN at Finch TS

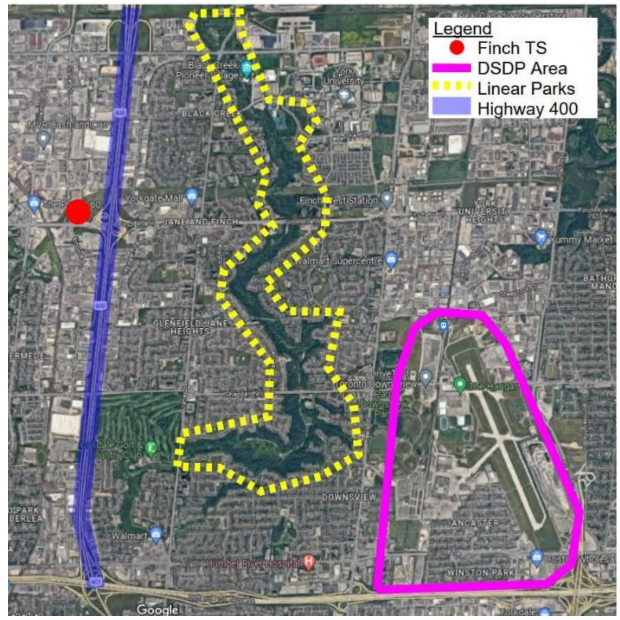


Figure 10 – Finch TS in Relation to the DSDP Area and Geographical Barriers

As a result of these implementation challenges and geographic barriers, there is a large risk that in the long term a significant portion of the new capacity installed at Finch TS will become stranded, while the adjacent Bathurst TS and Fairbank TS become overloaded. This risk is another signal that the new capacity has been incorrectly placed within the Downsview Area.

In addition to execution risk, this option carries a risk to cost which is expected to be even more likely to materialize. In order to overcome at least some of the challenges mentioned, and because of the high quantity of load transfers required, there is a high likelihood that the cost to complete the required load transfers will be significantly higher than average costs. Regarding the magnitude of load as being a driver of cost, this is because when large quantities of load are transferred, accompanying civil work such as new poles, duct banks, and/or cable chambers must be also be constructed.

In conclusion, the expansion of Finch TS is the only existing station in the Downsview Area which can accommodate an expansion. The expansion of Finch TS would introduce 174 MW of new capacity to the Downsview Area, and is expected to bring Downsview Area loading down to 90% until 2041. To achieve this outcome, an estimated $119 million in Hydro One Contributions is needed over 2025-2031, and an unprecedented 290 MW in load transfers is needed over 2024-2044. Because of congestion and geographical barriers, there is a high risk in achieving the total magnitude of load transfers required, which is expected to result in higher than average load transfer costs and stranding of the new capacity provided. The mentioned large risks and the need for an excess quantity of load transfers has motivated consideration of option 6, which seeks to add new capacity directly where it is needed.

4.6 Option 6: New Station (“TS”)

This Option considers building a new transformer station within the Downsview Area, in order to bring new capacity to the area. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this Option proposes to build a new transformer station, named “Downsview TS”, within or on the border of the DASP area. Not only will this facilitate supply of the DASP loads directly, but the DASP area is also located in proximity to all stations in the Downsview Area requiring load relief: Bathurst TS, Fairbank TS, and Finch TS. Therefore, a new station in the DASP area will also be well placed for providing load relief. Similar to option 4, this option considers the installation of one new DESN providing 174 MW of new capacity and suppling 12 new feeders.

Given Downsview TS, the Downsview Area loading is shown at 5-year intervals in Figure 11. Despite the addition of the new DESN, the 25 Year Forecast estimates that the Downsview Area loading will reach 90% again by 2041. FES projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. However, the Downsview TS is expected to resolve Downsview Area loading issues in the long term. To mitigate the risk of overloading in the long term, Downsview SS (introduced below) is proposed to be constructed with the provision to install a second DESN in the future, when it is needed.

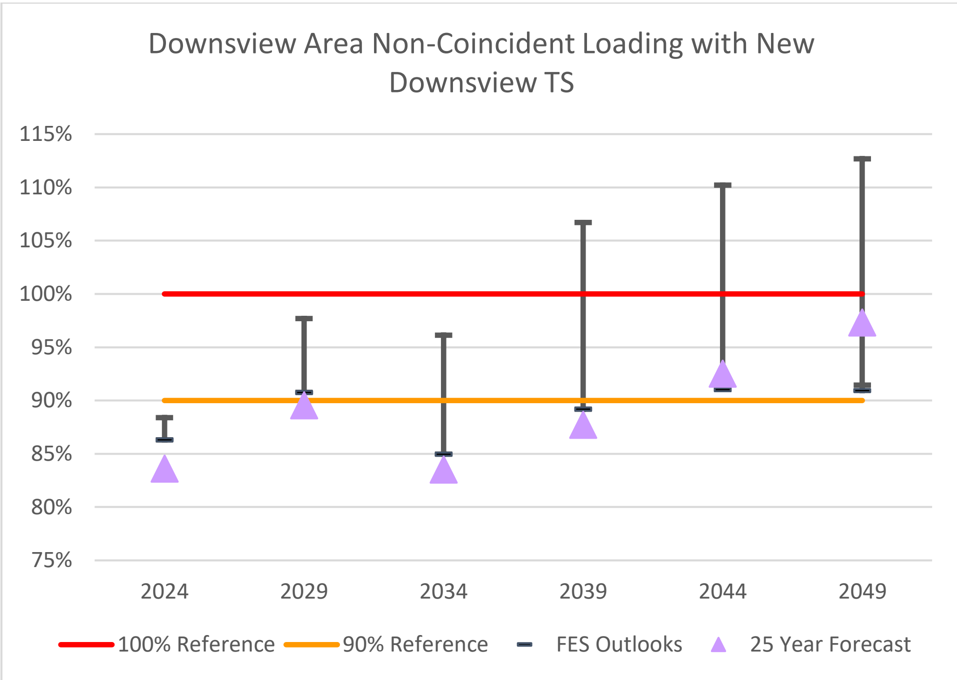


Figure 11 – Downsview Area Loading Following the Energization of Downsview TS

The scope of work of this option involves both a Hydro One and Toronto Hydro portion. The Hydro One portion includes the construction of a new switching station ("Downsview SS") in the vicinity of the Hydro One right-of-way along Finch Ave W, which will serve as the supply and demarcation point for Toronto Hydro's new Downsview TS. The Toronto Hydro portion of work will include the procurement of land for Downsview TS and the construction of: 230 kV underground cables and duct banks from Downsview SS to Downsview TS, a new station building, two primary circuit breakers and transformers, and one switchgear. Because of the large scope of work, Downsview TS's in-service date is estimated to be Q4 2033, assuming it begins in Q1 2025.

Based on estimates of the costs for each major asset installed, and an estimated schedule of the project, an annual cost estimate was developed and is shown in Figure 11. The total cost over 2025-2033 is estimated to be $170 million, excluding inflation assumptions, comprising of $118 million in Toronto Hydro costs and $52 million in Hydro One Contributions.

Because the Peak Demand Forecast anticipates stations loading past 90% before Downsview TS will be ready, this option assumes the load transfers presented in option 2 will be completed to manage station loading in the meantime. Once Downsview TS is ready in 2034, load transfers will be completed to offload the existing stations. Because Downsview TS will be located in the vicinity of the DASP area, it will be able to directly supply the new loads without additional load transfers. As a result, no significant load transfers are anticipated until the Downsview Area loading is forecasted to reach 90% again in 2042. In total, 252 MW in load transfers are expected by 2044. The expected load transfers in 5-year increments are shown in Figure 12. Load transfers increase in 2045 again to prevent overloading at Downsview TS.

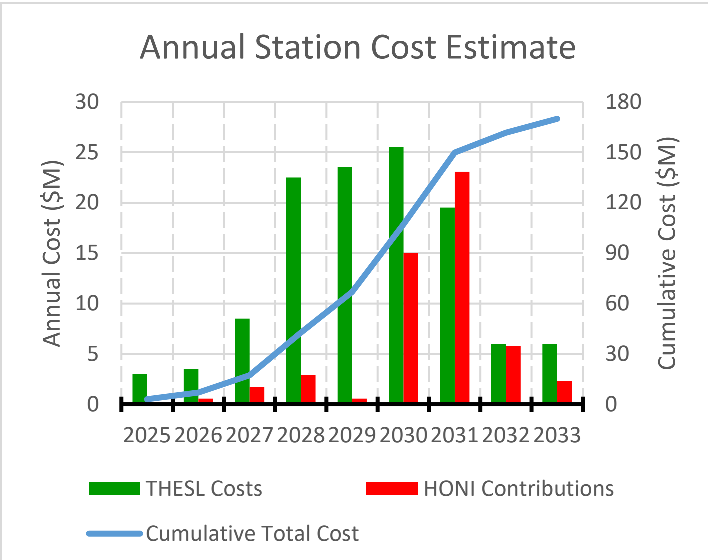


Figure 12 – Estimated Annual Expenditures for Downsview TS[6]

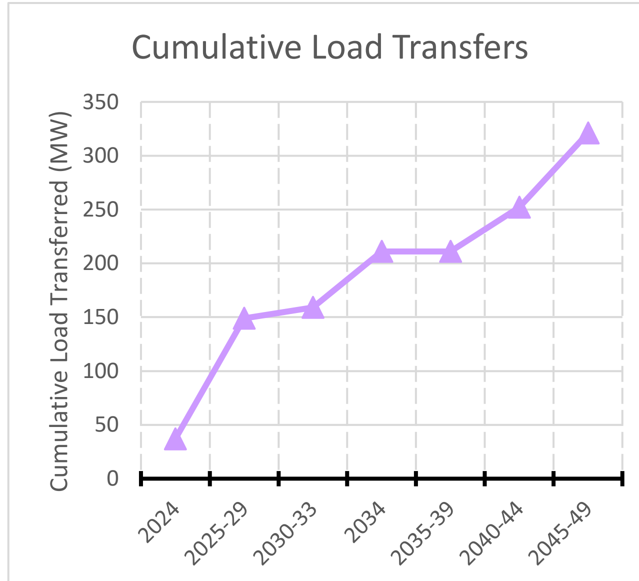


Figure 13 – Cumulative Load Transfers Required for Downsview TS

In conclusion, this option presents a feasible solution by constructing a new Downsview TS and introducing 174 MW of new capacity to the Downsview Area. This investment is expected to bring the Downsview Area loading down to 90% until 2041. To achieve this outcome, an estimated $170 M[6] of expansion work is needed over 2025-2033, and an estimated 252 MW in load transfers is needed over 2024-2043. This option will also include the provision to install a second DESN in the future to mitigate the risk of subsequent overloading in the Downsview Area in the long term.

[6] Excluding inflation assumptions

5 OPTION ANALYSIS AND RECOMMENDATION

The key results of the options studied are summarized in Table 4. Options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, Option 6 – New TS, as the only option capable of meeting system needs with reasonable risks.

Table 4 – Summary of Options

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2044 or Earlier] (MW)[7]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	193	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	290	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	252	Minimal	Medium	Mitigated

[7] Load relief (as load transfers or NWAs) required past 2044 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2044, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for Option 2 – Load Transfers showed that the Option is only viable up until 2029, and as a result it was also rejected.

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to be addressed, 193 MW. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are “designed to help address short-to-medium term capacity constraints”, and are not designed to be long term solutions. Moreover, Toronto Hydro’s NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 193 MW by 2044 is highly unprecedented which translates into a very high execution risk. Therefore, because it is not designed to be a long-term solution and its very high execution risk, this option was rejected.

Option 4 – Station Upgrades was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically unfeasible and was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Downsview Area; but as mentioned in Section 4.5, only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this option is forecasted to require a remarkably high quantity of load transfers, 290 MW by 2044, to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by this option, this option was ultimately rejected.

Motivated by the challenges encountered in its analysis of option 5, Toronto Hydro next considered installing new capacity both within the DASP area where new capacity is needed most, and in a central location within the broader Downsview Area to facilitate relief of the existing stations. This resulted in Option 6 – New TS which specifically considers installing a new TS within the DASP area, and whose details are reviewed next.

Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. However, the construction of a new TS is a long and complicated project; and therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous option 5 at 252 MW. Option 6 also includes a provision to address the risk of subsequent overloading in the long term (illustrated in Figure 11), by permitting a second DESN to be installed at the newly constructed TS, whereas no such provision exists in option 5.

In light of the multiple benefits of Option 6 – New TS shown over Option 5 – New DESN(s), and given the multiple significant drawbacks of Option 5, Toronto Hydro selected Option 6 – New TS as the only reasonable solution to address capacity needs within the Downsview Area. Toronto Hydro proposes to implement option 6 with its Downsview TS Project included in its 2025-2029 rate application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Downsview Area due to forecasted high station loading in the medium term, and forecasted Area overloading in the long term from the Downsview Area Secondary Plan ("DASP").

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its Option 6 – New TS is the only reasonable option which addresses system needs.

The recommended option will construct a new TS, Downsview TS, which will provide 174 MW of new capacity to the Downsview Area, with forecasted energization in Q4 2033. The proposed location of Downsview TS is in proximity to the lands of the DASP, and also central to the Downsview Area. This will permit it both to directly supply new DASP loads, and relieve the highly loaded Bathurst TS, Fairbank TS, and Finch TS.

The cost to construct the new TS is estimated to be $76.0 million over the 2025-2029 period and $116.2 million over the 2030-2034 period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost is planned to be capitalized in the 2025-2029 period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

Because of the long construction timeline, load transfers and/or NWSs will be needed in parallel with construction of the new TS. An estimated 149 MW in load transfers or NWS capacity will be needed by 2029, and a subsequent 62 MW between 2030-2034.

Downsview TS will be constructed with a provision to install an additional 174 MW of capacity when needed in the future. This will address the risk of subsequent high loading or overloading. The 25 Year Forecast forecasts 90% loading to reoccur after 2041, and the FES projections project this to occur as early as 2034 despite the energization of Downsview TS.

The proposed investments will address upcoming high loading in the Downsview Area, support the City of Toronto's Downsview Area Secondary Plan, and prepare the Downsview Area to support electrification over the next 10-20 years.

Scarborough TS Expansion Business Case

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1 EXECUTIVE SUMMARY

Project Name	Costs	
Scarborough TS Expansion	$	56.3 M

This project will address forecasted capacity constraints in the East end of the City due to confirmed large customer requests, the Golden Mile Secondary Plan, and electrification.

The proposed solution is to install a new DESN at Scarborough TS, due to its central location in the area, as well as its proximity to the highly-loaded Warden TS.

The scope of work involves constructing a new building, two new transformers, and one new switchgear at the Hydro One-owned station, which will provide 95 MW of new capacity. The new transformers and new building will be constructed with a provision to install a second switchgear. When needed, the second switchgear will provide an additional 95 MW of new capacity to the area.

The project cost is estimated to be $51.3 million in the 2025-29 period, and $5.0 million in 2030. The project's in-service date is planned for December 2030, and the full $56.3 million project cost is planned to be capitalized in 2031 following energization.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of: Bermondsey TS, Ellesmere TS, Scarborough TS, and Warden TS. This area is show in Figure 1. This area will be called the “Scarborough area” throughout the rest of this document.

In recent years, the Scarborough area has been attracting a large amount of new load, and that trend is forecasted to persist into the future. Recent large projects in progress involve an 84 MVA data centre, an 80 MVA Metrolinx connection for the Ontario Line, and a 36 MVA TTC connection for the Scarborough Subway Extension. On average, the area is forecasted to grow by 4.1% per annum over the next 10 years.Table 1 shows the existing load forecast for Scarborough TS and its adjacent stations based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Warden TS is forecasted to quickly become highly loaded due to the onset of new large customer connections. Load transfer projects to relieve Warden TS have already been initiated and included in the forecast to prevent overloading, but high loading persists due to demand in its service territory.

Ellesmere TS is forecasted to become highly loaded by the end of the 2025-29 rate period. This growth is being driven by several large customer connection requests, including transit. The expectation is that new customer connections will become challenging to accommodate, particularly due to high feeder loading.

While Bermondsey TS is not forecasted to reach the high load threshold of 90%, its load is forecasted to double over the next 10-years. This rapid load growth is driven mostly by the Ontario Line transit project, a new large data centre connection, and load transfers from Warden TS.

There is a consistent trend of high growth throughout the Scarborough area, and by 2031 it is forecasted to be highly loaded at 90%. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification.

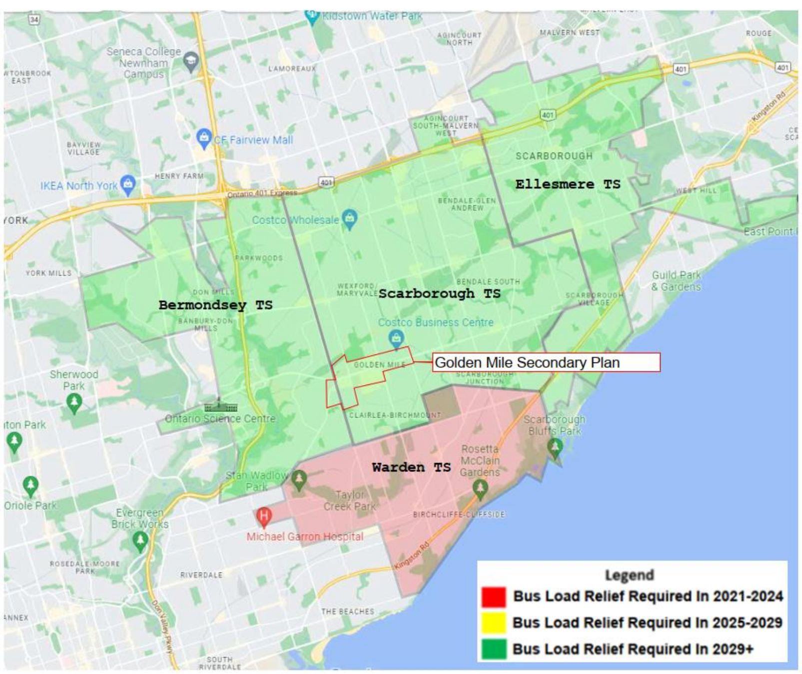


Figure 1 – Map Scarborough TS and its Adjacent Stations

Table 1 – Non-Coincident area 10-Yr Load Forecast[1]

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bermondsey TS	348	45%	57%	67%	71%	73%	73%	85%	85%	85%	86%	88%
Ellesmere TS	189	63%	65%	71%	84%	88%	88%	89%	**95%**	**96%**	**96%**	**96%**
Scarborough TS	340	64%	68%	71%	78%	79%	79%	79%	84%	85%	86%	86%
Warden TS	182	80%	85%	78%	**91%**	**92%**	**94%**	**93%**	**93%**	**94%**	**94%**	**95%**
Area Non-Coincident %	**1059**	**61%**	**67%**	**71%**	**79%**	**81%**	**81%**	**85%**	**88%**	**88%**	**89%**	**90%**

2.2 Golden Mile Secondary Development Plan

In 2020, the City of Toronto adopted the Golden Mile Secondary Development Plan ("GMSDP"), which proposes a mixture of residential, commercial, and office building development. The Golden Mile is 113 hectares (280 acres) in size, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south as shown in Figure 2. The specific area within the map where development will take place is also shown in Figure 1. The development is located at the bottom edge of Scarborough TS and is just outside of Warden TS's service territory.

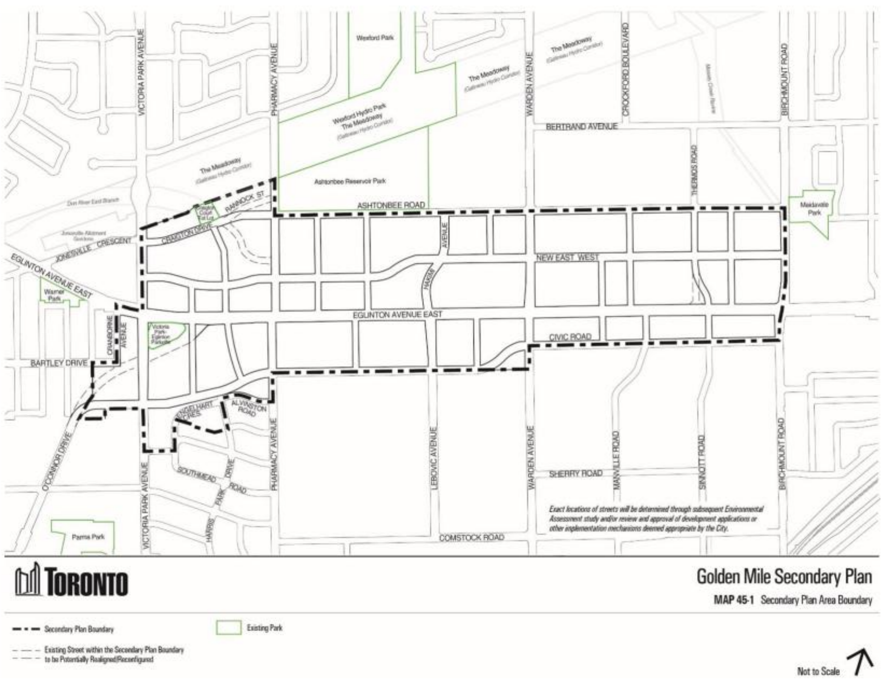


Figure 2 – Golden Mile Secondary Plan Map

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Report, Toronto Region, Dec 2022.

The GMSDP proposes a mixture of residential, commercial, and office building development. The area is expected to build a mixture of mid-rise and tall buildings, creating up to 5,000 new residential units. Additionally, the Plan proposes for each dwelling unit to provide an outlet for EV charging. The main focus of the development is to update the area with current infrastructure and prepare for electrification.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the Golden Mile Secondary plan. This study estimates that load will begin to materialize in 2030 and could be up to 280 MW by 2040. To meet this demand, station capacity should be available by 2030, and multiple phases of expansion work may be needed by 2040.

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating anticipated load and generation growth in the City of Toronto. As the City of Toronto moves through an energy transition, Toronto Hydro is anticipating its Scarborough area load will grow by 75-105 percent over the next 20 years, largely due to the electrification of heating and transportation. Therefore, regardless of how this transition happens, Toronto Hydro expects that its Scarborough area will face large capacity constraints without additional investment. Over the course of the energy transition, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system nor to existing customers looking to decarbonize.

In addition to the GMSDP discussed in the previous Section 2.2, the City of Toronto is also reviewing its Scarborough Centre Secondary Plan with its Our Scarborough Centre Study[2] currently underway. The redevelopment of Scarborough Centre spans an area of 180 hectares, and is focused on densification, improved accessibility, and the introduction of new transit. The development would introduce significant new loads to Ellesmere TS and Scarborough TS.

Given the current highly-loaded state of the area, the addition of the GMSDP, the likelihood of rapid electrification underway, and the likelihood of the Scarborough Centre redevelopment, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments. In particular, options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner.

[2] https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/scarborough-centre-review/information-and-reports-scarborough-centre-review/

3 SCARBOROUGH AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Golden Mile Load

The Peak Demand Forecast only extends to 2031; however, we will assume that the total area load growth past 2031 is provided exclusively by the GMSDP. The result will be called the "25 Year Forecast". The Peak Demand Forecast does not already include consideration for the GMSDP, and for this reason the GMSDP load is added starting in 2030.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the GMSDP. This study estimates that load will begin to materialize in 2030 and could materialize up to: 283 MW by 2040 and 304 MW by 2051. The annual load growth from this study was first adjusted to 70 percent[3], and then added to the Peak Demand Forecast. The results at 5-year increments are provided in Table 2.

Table 2 - Estimated Station Loads under the 25 Year Forecast

STATION	Summer LTR (MW)	2021 (Actuals)	2024	2029	2034	2039	Year 100% Capacity is Reached
Bermondsey TS	348	45%	71%	85%	**94%**	**101%**	2039
Ellesmere TS	189	63%	84%	**96%**	**96%**	**96%**	N/A
Scarboro TS	340	64%	78%	85%	**99%**	**112%**	2035
Warden TS	182	80%	**91%**	**94%**	**108%**	**120%**	2031
Area Non-Coincident %	**1059**	**61%**	**79%**	**88%**	**98%**	**107%**	2035

Under the 25 Year Forecast, the Scarborough area as a whole is forecasted to exceed 90 percent loading in 2030, soon after the 2025-29 period. By 2031, Warden TS is forecasted to reach capacity and the remaining stations are each forecasted to be highly loaded. Following that, Scarborough TS and the entire Scarborough area are forecasted to reach capacity in 2035. Over the next 3 rate periods from 2025-2039, with each rate period, the Scarborough area is forecasted to rapidly escalate to progressively worse states of loading, as summarized in Table 3.

[3] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Table 3 – States of Loading in the Scarborough area Over the Next 3 Rate Periods

	2025-2029	2030-2034	2035-2039
Area Highly Loaded (≥ 90%)	✗	✓	✓
All Stations Highly Loaded (≥ 90%)	✗	✓	✓
Area Overloaded (≥ 100%)	✗	✗	✓

In summary, the 25 Year Forecast reinforces the need for new capacity in the Scarborough area for the start of the 2030-2034 period, and shows that this need increases progressively until 2035 when the whole Scarborough area loading is forecasted to reach capacity.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

The 25 Year Forecast described in the previous section is the forecast Toronto Hydro has used to produce its proposed business plan. However, the 25 Year Forecast does not explicitly account for the electrification of heating loads, and therefore may be understated. To bridge this gap, Toronto Hydro has used the FES as a tool to assess the risk posed by electrification.

Across all Future Energy Scenarios, the model projects that all but one station will become highly loaded by 2031, and that the area as a whole will become overloaded between 2030 and 2034. Table 4 provides the station and area loading under the FES, and Figure 3 illustrates the area Non-Coincident loading under the FES.

Table 4 – Non-Coincident area 20-Yr Scenario-Based Load Forecast Results

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[4]
Bermondsey TS	348	44%	69-70%	78-82%	82-89%	84-95%	N/A
Ellesmere TS	189	66%	83-85%	**100-113%**	**109-135%**	**120-154%**	2028-2029
Scarborough TS	340	64%	78-80%	87-94%	**95-107%**	**100-118%**	2032-2039
Warden TS	182	82%	**102-104%**	**125-134%**	**135-151%**	**140-174%**	2024
area Non-Coincident %	**1059**	**61%**	**80-82%**	**93-99%**	**100-111%**	**104-123%**	2030-2034

[4] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

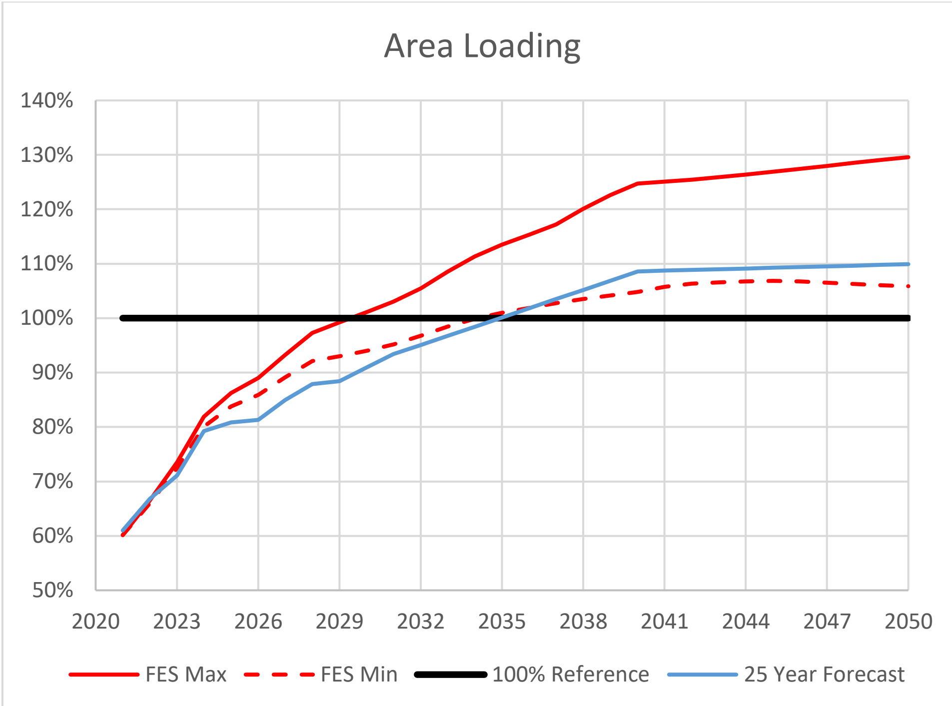


Figure 3 - Non-Coincident area 20-Yr Loading from the FES Projections

In summary, the Future Energy Scenarios also demonstrate the need for new capacity in the Scarborough area for the end of the 2025-2029 period. Furthermore, FES shows that this need may materialize much sooner than predicted by the 25 Year Forecast. Overall, the FES affirms the need for new capacity in the Scarborough area which is predicted by the 25 Year Forecast.

3.3 Sensitivity Conclusions

Two approaches were considered to assess loading impacts to the area based on the Golden Mile Secondary Development Plan (GDSMP) and the Future Energy Scenarios. In both approaches, the Scarborough area is forecasted to be highly loaded near the end of the 2025-2029 Custom-Incentive Rate Filing period. This is marked by overall area loading reaching 90 percent or higher by 2031.

Moreover, both approaches indicate a continuing need for additional capacity into 2040. In fact, the GMSDP's estimated load buildup of 280 MW over 2030-2040, or 26 percent of the area's capacity, is just as aggressive a buildup as the Maximum projection from the FES over the same period. Both approaches predict the Scarborough area overloading over 2030-2035, with load growth continuing thereafter.

The Scarborough Centre Secondary Plan and the resulting Our Scarborough Centre Study result in an additional risk for even further load growth, which has not been explicitly captured in either approach. The redevelopment of Scarborough Centre would add substantial load to the Scarborough area, and reiterates a long term need for new capacity in the Scarborough area.

In conclusion, multiple perspectives were considered when conducting a load sensitivity analysis, and all perspectives conclude with the Scarborough area loading reaching capacity in approximately 7-12 years.

4 OPTIONS CONSIDERED

To address the needs of the Scarborough area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Scarborough area at or below 100 percent. Specifically, this option assumes that load transfers will be completed just as each station reaches 100 percent loading, and only to the extent to keep the station at 100 percent loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Load Forecast in Table 1 in Section 2, Warden TS will reach 100% loading in 2024 but the other stations will be under 80 percent loading. Therefore, this option is possible; however, it will present large operational and reliability risks. Risks rapidly increase past 2024, when all scenarios estimate at least 1 station's loading to reach 100 percent.

As a minimum consequence, the Load Forecast predicts the Scarborough area will become highly loaded by the end of the upcoming 2020-24 rate period. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers. Given the incoming Golden Mile load, the Scarborough area may see more rapid increases in load. The cumulative load needed to be transferred and its required timing is provided in Table 5 below. The area is forecasted to be overloaded in 2035.

Table 5 – Load Transfers Required to Maintain Station Loading ≤ 100%

Load Transfers Required (MW) per Rate Period			
2024	**2025-29**	**2030-34**	**2035-2039**
0	0	14	area Overloaded

The FES projections predict a much more rapid load growth, and by contrast load transfers are needed over the 2024-2033 period. The FES projections predict that the Scarborough area will become overloaded by 2029-34.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risks involved in running stations at 100 percent loading. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focus" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a farther station with capacity. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines.

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[5] to avoid damaging the remaining assets. As a result, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term interim solution.

In conclusion, this option is not a feasible solution. This option requires a high level of risk to be maintained and managed for an unacceptably long period, into 2034; and past 2034, this option cannot be implemented at all since the entire area will reach 100 percent loading.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once every 5-year period, to maintain station loading throughout the Scarborough area at or below 90% over the period. This is done to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

Given the 25 Year Forecast provided in Table 2 of Section 3.1, the Scarborough area will reach 90 percent loading by 2030. Table 6**Error! Reference source not found.** below shows that 22 MW in load transfers will be needed over the 2025-29 period, and that area loading will surpass 90 percent loading after the 2025-29 period.

Table 6 – Annual Load Transfers Required to Maintain Station Loading ≤ 90%

Forecast	**Annual Load Transferred (MW)**		
	2024	**2025-29**	**2030-34**
Golden Mile Load	2	22	Above 90%

The FES projections estimate that the Scarborough area will exceed 90 percent loading between 2026-27, making this option infeasible for the 2025-29 period. In addition to GMSDP loads, Toronto Hydro is aware of the Scarborough Centre Secondary Plan but does not have an estimated load profile at this time. This Plan adds further risk to this option.

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2029. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

4.3 Option 3: Non-Wires Solutions

This option considers the possibility of addressing high loading and overloading within the Scarborough area using Non-Wires Solutions (”NWSs”), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

[5] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response (“LDR”).

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro’s distribution system. According to the 25 Year Forecast, 179 MW of LDR capacity would be needed by 2039 in order to maintain the area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution.

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered for short-to-medium term solutions.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

This option considers the possibility of expanding the capacity of existing DESNs in the Scarborough area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

Of all the stations in the Scarborough area, Bermondsey TS, Ellesmere TS, and Warden TS are already sized to their maximum ratings. The Scarborough TS T23 transformer can be upgraded, and this upgrade is already proceeding through Hydro One sustainment plans during the 2025-29 period. The incremental cost to upgrade the end-of-life Scarborough T23 transformer as it undergoes renewal is $0.4 million. The upgrade is planned to be complete in 2028, and will provide an estimated 38 MW of new capacity to the Scarborough area.

Figure 4 below shows the Scarborough area loading after Scarborough TS’s transformer upgrade. After the transformer upgrade, the Scarborough area is projected to exceed 90 percent loading by 2031 and will require load relief.

In conclusion, this option is not a feasible solution, since it can only satisfy system needs up until 2030. To address needs in time for the 2030-2034 period, other options must be initiated in the 2025-2029 period.

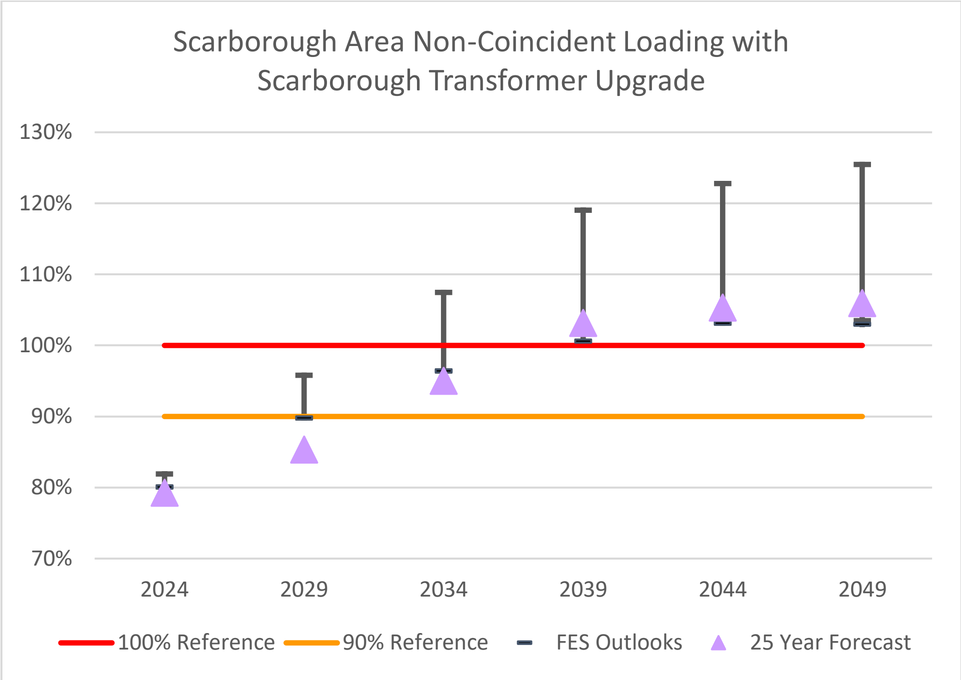


Figure 4 – Scarborough area Loading Following Scarborough TS Upgrade

4.5 Option 5: New DESN(s)

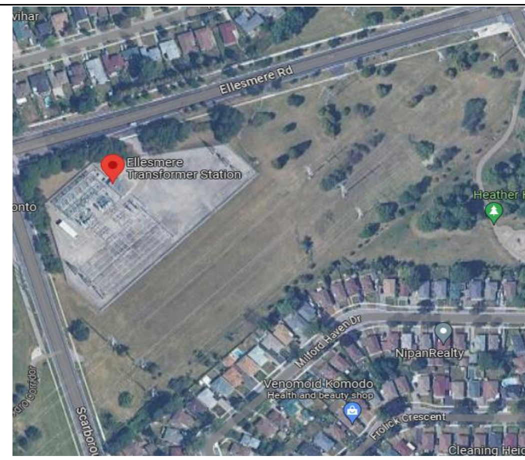
This option considers adding one or more new Dual-Element Spot Networks (“DESNs”) at the existing stations in the Scarborough area, referred to as “station expansion”. A typical Jones DESN provides 95 MW of new capacity and supplies 6 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connect costs required for a new station.

This option also assumes that option 4.4 Station Upgrades has been completed, introducing 38 MW by 2028, since the Scarborough TS transformer upgrade is already proceeding due to Hydro One sustainment plans.

Of the four existing stations in the Scarborough area, only two have sufficient space at the station to consider expansion and are located in proximity to the Golden Mile area, the source of future load growth. As a result, only these two stations, Scarborough TS and Warden TS, are considered for expansion.

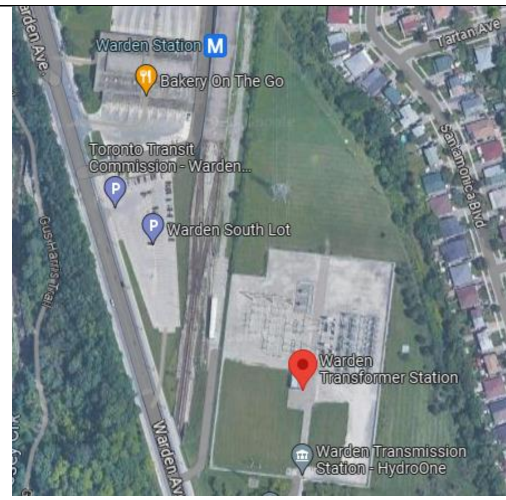
Bermondsey TS already has plans underway to expand its JQ DESN by an additional 6 breakers, which will utilize remaining space. Ellesmere TS does not have enough space for expansion in the current lot. In both cases, new installations directly beneath transmission lines are to be avoided, which eliminates the remaining space around Bermondsey TS and Ellesmere TS. Aerial views of the existing stations are provided in Figure 5 below.

Bermondsey TS



Ellesmere TS

Scarborough TS



Warden TS

Figure 5 – Aerial Overview of Existing Stations in the Scarborough area

The Scarborough area loading is shown at 5-year intervals in Figure 6, given the addition of one new Jones DESN rated for 95 MW and the Scarborough TS transformer upgrade. The new DESN is expected to come in service at the end of 2030. While these investments will address the needs identified for the early 2030-2034 period described in Section 3.1, loading is forecasted to again reach 90% in 2036, signaling the need for subsequent new capacity at that time.

Similarly, the Future Energy Scenarios predict that 90 percent loading may begin and persist as early as 2027, and that area overloading may begin as early as 2035. Therefore, the FES also demonstrate the risk that subsequent new capacity will be needed beyond the new Jones DESN and Scarborough TS transformer upgrade.

To address the risk of subsequently overloading, this option is proposed with the provision to install a second DESN in the future. This will be achieved by installing two 125 MVA dual winding power transformers as part of this project, which is Hydro One’s standard equipment for new DESNs at this voltage level, leaving two idle windings free for a future second DESN. The second DESN will provide a subsequent 95 MW of capacity to the area, and can be initiated when needed. Once complete, the second DESN will provide sufficient capacity to keep area loading below 90 percent until 2042.

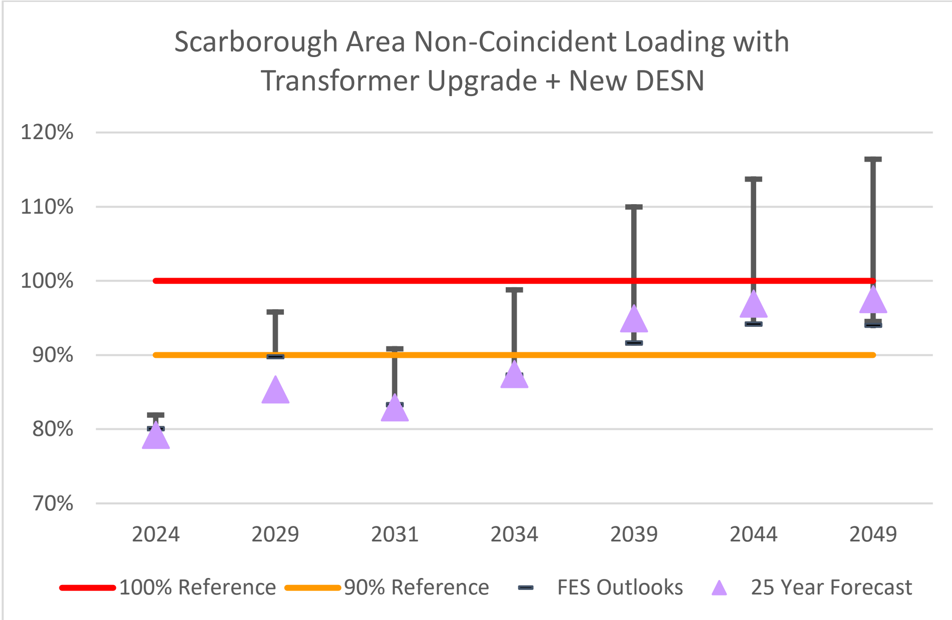


Figure 6 – Scarborough area Loading Following New DESN

The scope of work involved will be similar to the expansion project recently completed at Horner TS in 2022. As Scarborough TS is a Hydro One-owned station like Horner TS, Hydro One will complete the entire scope of work, involving: clearing space for the new DESN within or around the existing station, installing two new 125 MVA power transformers, installing a new gas-insulated switchgear and feeder tie switches, constructing a new building for the switchgear and control equipment, and connecting the transformers to Hydro One transmission lines. The total cost in Hydro One Contributions is estimated to be $56.3 million with a project timeline of 6 years, based on the experience of the Horner TS expansion. The start date would be Q1 2025 with an in-service date of Q4 2030. The annual estimated Hydro One Contributions are provided in Figure 7.

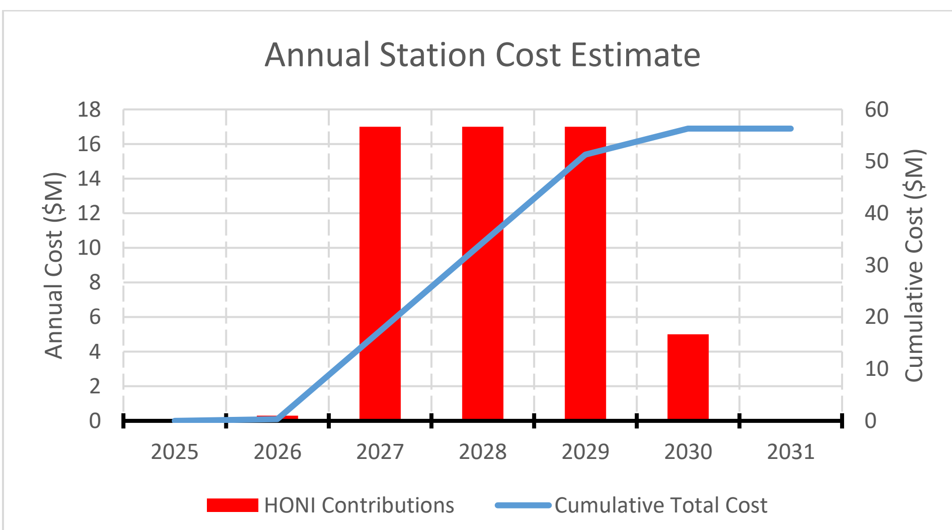


Figure 7 – Estimated Annual Hydro One Contributions for new DESN at Scarborough TS

From the perspective of high-level estimating, the scope of work to expand either Scarborough TS or Warden TS is estimated to be the same. As a result, the high-level cost estimate for both options is also the same at this time. Likewise, as shown in Figure 8, the quantity of load transfers required after expanding either station is estimated to be similar.

However, based on local geography, Warden TS is expected to face significantly higher execution challenges and costs in station egressing[6] than Scarborough TS. Additionally, the transmission corridor to Warden TS consists of a run of single transmission towers, which carry both of the station's transmission line supplies. This places a higher reliability risk at Warden TS, since the collapse of any tower along the corridor will result in a sustained outage to the entire station. Last, Scarborough TS is located central to the Scarborough TS area, which permits it to readily offload any station in the area. For these reasons, Scarborough TS was selected for expansion, rather than Warden TS.

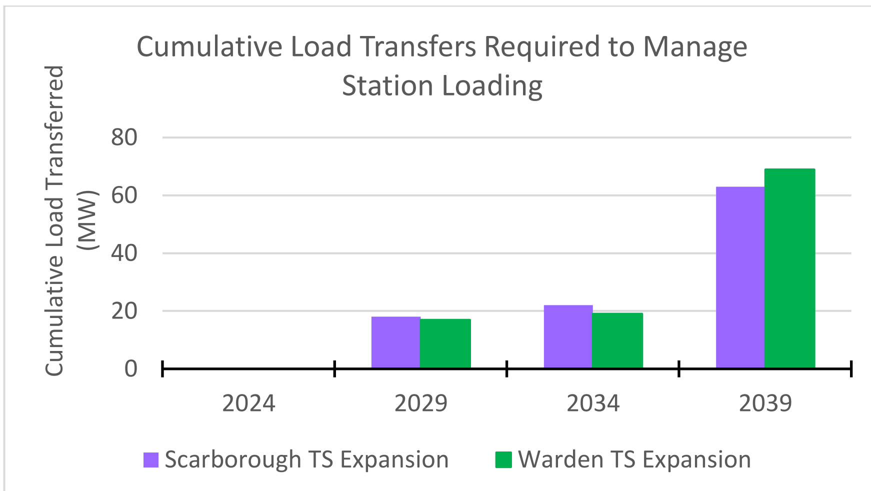


Figure 8 – Cumulative Load Transfers Required[7] for Each Expansion option

In conclusion, this option presents a feasible solution by introducing 133 MW of new capacity to the Scarborough area from a new DESN and a transformer upgrade at Scarborough TS. These investments are expected to bring the area loading down to 90 percent until 2036. This option also includes the provision for further expansion by an additional 95 MW, which when pursued will maintain area loading below 90 percent until 2042. The total cost of this option is estimated to be $56.7 million[8] with attainment in Q4 2030. In addition to expansion work, approximately 63 MW in load transfers will be needed over the 2025-2039 to manage the area.

[6] Station egressing includes the first portion of civil and electrical infrastructure between the Hydro One-owned station assets and THESL larger distribution system. This typically involves feeder cable trunks, large duct banks and cable chambers which run out of the station, and/or groups of overhead poles which run out of the station.
[7] Required to maintain station loading at or below 90%, or at the Area loading if the Area is loaded beyond 90%
8 The total cost of $56.7 million includes both the cost of the transformer upgrade ($0.4 million) and the cost of the new DESN ($56.3 million). Total cost has been used for the sake of fair option comparison.

4.6 Option 6: New Station ("TS")

This option considers the construction of a new transformer station ("TS") within the Scarborough area, in order to introduce new capacity and provide load relief. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this option proposes to build a new TS, located close to both the Golden Mile area and Warden TS, to address the new load and provide relief. The new TS would include the same electrical assets as the previous option 5: New DESN(s), and therefore will also introduce 95 MW of new capacity to the area.

The cost of building a new TS is estimated to be between $150-200 million and the time required is projected to take a minimum of 8 years. These estimates were developed based on past station expansion projects at Horner TS and Runnymede TS, and Toronto Hydro's experience in estimating its proposed Downsview TS project.

Since this option provides the same benefits as option 5: New DESN(s), but at a much higher cost, lead time, and execution risk, this option was not considered further.

5 OPTION ANALYSIS AND RECOMMENDATION

The key outcomes of the options presented are summarized in Table 7. options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, option 5 – New DESN(s), as the option capable of meeting system needs with the least cost and risk.

Table 7 – Summary of Options Outcomes

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Solution Outside of Short Term	Cumulative Load Transfers or NWSs Required [by 2039 or Earlier] (MW)[9]	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This option is only viable as a short-term interim solution while a long term solution is in progress.	No	N/A – viable only in short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This option can only manage loading until 2029.	No	N/A – viable only in short term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	179	High	Very High	Mitigated
4 – Station Upgrades	Reject	This option can only manage loading until 2030.	No	30	Minimal	Minimal	Forecasted Overload
5 – New DESN(s)	**Accept**	Meets system needs with reasonable risks and quantity of load transfers.	Yes	63	Minimal	Medium	Mitigated
6 – New TS	Reject	This option carries excessive costs, lead time, and risks in comparison to option 5.	Yes	68	Minimal	High	Mitigated

[9] Load relief (as load transfers or NWAs) required past 2039 is not considered in this Options Comparison, since the Downsview Area is forecasted to exceed 90% loading again in 2036, given Options 5 or 6. At that point, additional new capacity may be considered rather than additional load transfers or NWAs.

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for option 2 – Load Transfers showed that the option is only viable up until 2029, and as a result it was also rejected.

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to be addressed, 179 MW. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are “designed to help address short-to-medium term capacity constraints”, and are not designed to be long term solutions. Moreover, Toronto Hydro’s NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 179 MW by 2039 is highly unprecedented which translates into a very high execution risk. Therefore, because it is not designed to be a long-term solution and because of its very high execution risk, this option was rejected.

Option 4 – Station Upgrades was considered, but this option is capable of meeting system needs only up to 2030. Starting 2031, another solution would already need to be in place, and consequently that solution must be initiated in the 2025-2029 period. Therefore, this option was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Scarborough area; but as mentioned in Section 4.5, Scarborough TS is the preferred candidate due to location and reliability of transmission supply. A new DESN at Scarborough TS, in combination with a transformer upgrade already underway due to Hydro One sustainment work, will provide the Scarborough area with 133 MW of new capacity by 2030 with a provision to install a second DESN when needed. These investments will meet system needs until 2036, and the installation of a second DESN will provide sufficient capacity to continue to meet system needs until 2042. A moderate quantity of load transfers (or NWSs in-combination) of 63 MW over 2025-2039 will be needed to effectively address the needs of each station. Therefore, since this option meets system needs with the least level of intervention (resulting in least cost, lead time, and risk), Toronto Hydro selected option 5 – New DESN(s) as the only reasonable solution to address capacity needs within the Scarborough area.

Option 6 – New TS was considered for the sake of assessing a complete options analysis, despite the feasibility of option 5 – New DESN(s). This option would provide the same benefit as option 5, but with: approximately 3-4 times the cost, a minimum 2-year increase in an already long lead time, and a much higher execution risk due to the need to site and supply a new TS. Therefore, this option was rejected in favour of option 5.

In conclusion, Toronto Hydro selected option 5 – New DESN(s) as the only reasonable solution to address capacity needs within the Scarborough area. Toronto Hydro proposes to implement option 5 with its Scarborough TS Expansion Project included in its 2025-2029 Rate Application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Scarborough area due to forecasted high station loading in the medium term, and forecasted area overloading in the long term from the Golden Mile Secondary Development Plan (“GMSDP”).

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its option 5 – New DESN(s) is the only reasonable option which addresses system needs.

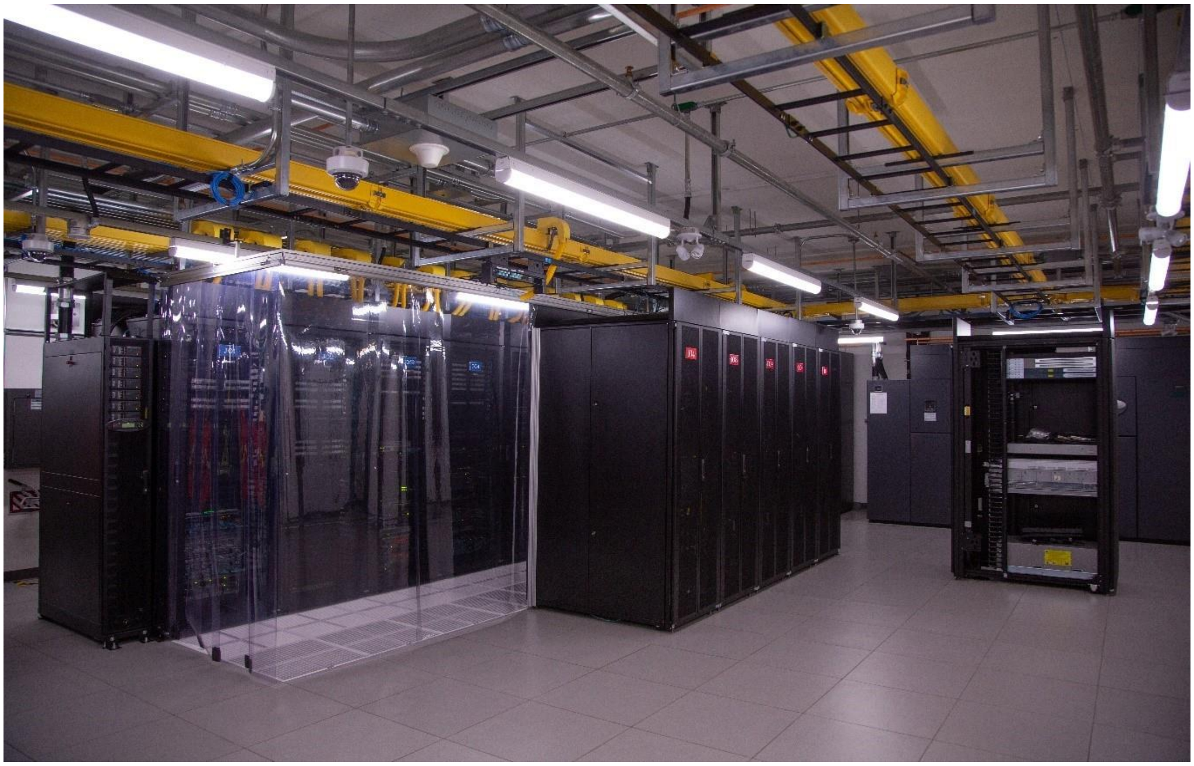
The recommended option will include an upgrade of the T23 transformer at Scarborough TS, and the installation of a new DESN at Scarborough TS. Forecasted completion is Q4 2028 and Q4 2030 respectively, and will provide 38 MW and 95 MW of new capacity respectively. The cost to upgrade the transformer is estimated to be $0.4 M, and the cost to construct the new DESN is estimated to be $56.3 M.

To manage station loading in the area, an estimated 18 MW, 4 MW, and 41 MW in load transfers or NWS capacity will be needed, respectively, in the following rate periods: 2025-2029, 2030-2034, and 2035-2039.

The new DESN proposed will be constructed with a provision to install a second 95 MW DESN when needed in the future, which will address the risk of subsequent high loading or overloading. Despite the proposed investments, the 25 Year Forecast forecasts 90 percent loading to reoccur after 2035, and the FES projections project overloading to occur as early as 2035.

The proposed investments will address upcoming high loading in the Scarborough area, support the City of Toronto’s Golden Mile Secondary Development Plan, and prepare the area to support electrification over the next 5-20 years.

E8.1 Enterprise Data Centre ("EDC") Relocation



E8.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): N/A	**2025-2029 Cost ($M):** $72.0
Segments: Facilities	
Trigger Driver: Operational Resilience	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Customer Focus, Financial Performance	

Toronto Hydro's 24/7 operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems, and server infrastructure across two distinct locations ("centres") that collectively support the following organization-wide ("enterprise") processes ("data"):

- Control centre operations, including real-time control of Toronto Hydro's distribution system through supervisory control and data acquisition ("SCADA"), and remote monitoring and operation of substations and in-field devices;
- Grid management and response, including outage management, isolation and restoration activities, and radio communications with field personnel;
- Delivery of planned investments, including capital and maintenance activities;
- Asset management activities, including system planning, analytics and decision-making, and regulatory reporting functions;
- Financial activities, including capital budgeting and financial reporting;
- Engineering activities, including design, cost estimation, and job scheduling;
- Customer services, including customer care and billing, call centre operations, meter reading, meter data management and customer communications; and,
- Information technology ("IT") services, including IT systems and software, technical support services, office phone systems, and online services.

Figure 1 illustrates the foundational role that the EDC plays within Toronto Hydro, and how a failure of this physical infrastructure could result in an organization-wide outage impacting all enterprise processes.

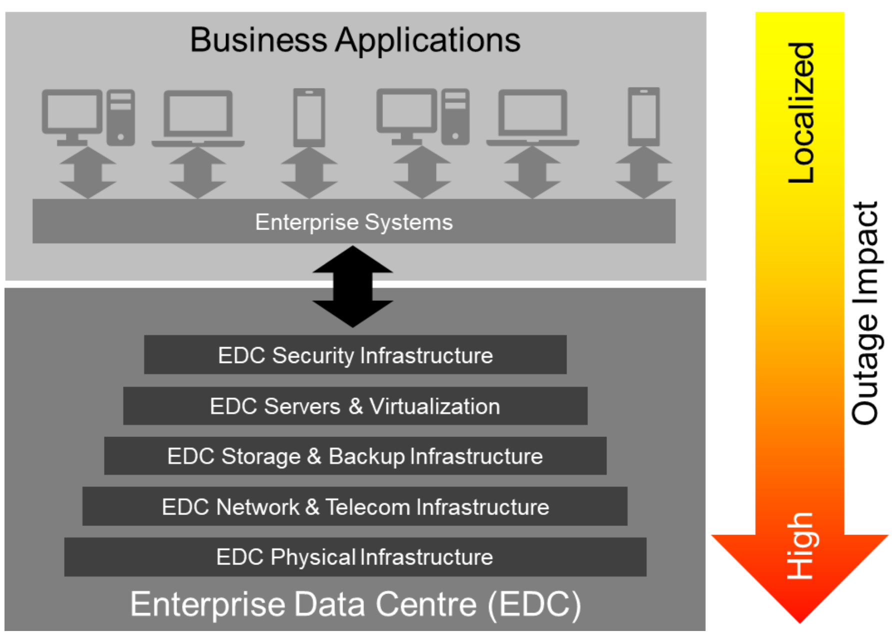


Figure 1: EDC and Supported Business Applications

An organization-wide outage would immediately disrupt operational systems and processes within Toronto Hydro's Control Centre Operations program, because power system controllers would be unable to access any real-time or near-real-time data within the Advanced Distribution Management System ("ADMS"), Outage Management System ("OMS") or Supervisory Control & Data Acquisition ("SCADA") systems.[1] Planned and unplanned activities within the utility's distribution system would suffer immediate disruption due to the loss of communication between the control centre and field crews, meaning that isolation, sectionalisation, and restoration activities would no longer be performed safely or effectively, resulting in extended outages to customers and significant delays in planned construction activities.

To better safeguard Toronto Hydro and its customers against the severe and significant impacts that an organization-wide outage could introduce, the EDC has been implemented across two physically separated locations for the purposes of providing redundancy and enhanced resiliency, should one or both EDC locations experience a normal or catastrophic failure event. Having multiple physically separated data centres is a common practice in the industry to enhance overall reliability, with recent surveys indicating that over 85 percent of organizations have three or more physically separated data centres in operation.[2] [redacted]

Toronto Hydro's EDC is facing emerging operational resilience, reliability, safety and security, and decarbonization issues specific to EDC 1 that require immediate intervention to mitigate the risks of a potential organization-wide outage. [redacted] 60 percent of the existing building infrastructure and facilities assets at EDC 1 are beyond their useful lives. Furthermore, Toronto Hydro has limited options to invest in necessary upgrades to building envelope systems at EDC 1 that can help mitigate current EDC capacity constraints. These growing facilities-related challenges are contributing to increased reliability risks for the EDC, including water damage, flooding, and physical safety and security risks that, if realized, would require the EDC to

[1] Exhibit 4, Tab 2, Schedule 7.
[2] See e.g. E. Thorne, "Corporate Data Center Geography, Explained", TeleGeography Blog, 2021, https://blog.telegeography.com/corporate-data-center-geography-explained

shut down. Finally, although Toronto Hydro estimates that it can fully meet its decarbonization goals with respect to the [redacted] Current energy efficiency goals as established by the Building Owners & Managers Association ("BOMA") and Energy Star are simply unfeasible to achieve within the EDC 1.

As Toronto Hydro continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, distributed energy resource ("DER") owners and operators, and other stakeholders, it will aim to modernize its infrastructure and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period. In other words, the EDCs will need to continue to grow to consistently meet the utility's, and by extension, its customers' needs. Although Toronto Hydro has prudently managed and maintained reliability and operational resilience within both EDC locations through its robust asset management strategy and asset renewal and repair activities,[4] the utility expects that EDC 1 will reach its capacity within the next five years and will no longer be able to accommodate new data and support new systems. Once this capacity threshold is reached, EDC 1 will no longer provide 1:1 redundancy to EDC 2. Under such a scenario, there will be a partial loss of business applications across the organization.

EDC 1 suffers from additional risks due to its limited and restricted footprint within the [redacted] which could increase the overall probability of an EDC failure event. For example, EDC 1 will continue to require at least two to three shutdowns per year to allow for the execution of necessary and essential facilities operations and maintenance activities aiming to safeguard the integrity of the location. Should EDC 2 fail during a shutdown of EDC 1, or should both EDC locations be impacted by a single event, an organization-wide outage will occur.

The EDC Relocation program (the "Program") proposes to relocate EDC 1 to [redacted] to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage. Through this relocation, Toronto Hydro will also be able to mitigate risks associated with operational resiliency, reliability, safety and security, and decarbonization. Subsection E8.1.2.1 on page 6 provides further details on the proposed investments within this

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3 [redacted]

4 Respectively discussed under Exhibit 2B, Sections D5 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 14 (Facilities Management OM&A program).

program, while subsection E8.1.2.2 on page 15 provides further details on the key drivers and risks to be mitigated through the execution of this program.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability and resiliency objectives by: ○ Reducing the risk of an organization-wide outage due to EDC failure; ○ Maintaining critical business applications, including control centre functions, grid management and response, planning and engineering, customer care and billing, and project execution; ○ Mitigating current reliability challenges due to the constraints and external factors at EDC 1; and ○ Enhancing the geographic diversity of the EDC to create redundancy and mitigate the risk of failure by reliance on a single EDC facility.
Operational Effectiveness - Safety	Contributes to Toronto Hydro's safety objectives by: • Mitigating health and safety hazards from building infrastructure deterioration at EDC 1 (raised floor, windows, life safety infrastructure and fire suppression); and • Providing safe access to the relocated EDC for deliveries and during the loading/unloading of components.
Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Allowing for customer service and call centre operations to continue uninterrupted in the event that one of the EDCs fail and minimizing the risks of potential call centre outages; and ○ Mitigating the risks of an organization-wide outage that can result in the extension of outages to customers.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Assisting with the achievement of goals outlined in Toronto Hydro's Net Zero 2040 Strategy by reducing scope 1 greenhouse gas emissions; and ○ Leveraging energy efficient HVAC and lightning systems.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Reducing capital costs by sharing existing infrastructure at the proposed EDC including cabling pathways, physical security, access control, and power redundancy solutions; and ○ Leveraging an existing fiber-optic connection between EDC 2 and the proposed EDC to reduce project costs.

E8.1.2.1 Program Description

This program proposes the relocation of EDC 1 to the [redacted] Toronto Hydro will require $72 million over the 2025-2029 rate period to execute and complete this program.

The utility proposes the [redacted] as the optimal relocation site for the following reasons:

- [redacted] and
- Existing Fibre-Optic Connections and Footprint: The proposed EDC contains a fibre-optic connection with EDC 2, which would enable the transfer of data and communications from the [redacted], thereby reducing overall project costs when compared to other potential locations. The proposed EDC also provides a [redacted] square feet footprint, which is necessary for housing all EDC assets.

Further details regarding the various relocation options and how the utility determined the optimal relocation site are provided in subsection E8.1.4 on page 23.

The proposed EDC will be a [redacted] to the existing warehouse area within the [redacted] and the EDC will be located [redacted] A total of [redacted] square feet of space will be dedicated to house the following key components:

[5] From the completion of the Control Operations Reinforcement program in Exhibit 2B, Section E8.1 of Toronto Hydro's 2020-2024 Custom Incentive Rate Application (EB-2018-0165). See also Exhibit 2B, Section E4 of this application.

- Physical Infrastructure: Provides the necessary vertical and horizontal space requirements to load, test and integrate, and store core assets within the proposed EDC. This includes the data hall, staging area, access trap, and loading dock;
- Electrical Infrastructure: Powers the EDC and provides redundancy should a localized failure at the proposed EDC occur. This includes the electrical supply points, uninterruptible power supply ("UPS"), and generators;
- Environmental Infrastructure: Maintains optimal environmental conditions within the EDC, while also providing essential protection against threats such as fires. This includes the HVAC and fire suppression systems;
- Telecom Infrastructure: Connects the EDC to Toronto Hydro's Control Centres, work sites, offices, substations and distribution system components;
- Network Infrastructure: Facilitates communications between servers, storage, and applications;
- Storage and Backup Infrastructure: Provides centralized storage of all production, test, and development data for online access and long-term archival;
- Computing Resources: Includes the servers, which provide the necessary processing, memory, virtualization, and connectivity to support business applications and associated middleware/database components; and
- Security Infrastructure: Enables physical and cyber security controls to sufficiently protect assets contained within the EDC.

The Program aims to retire the existing assets and infrastructure at EDC 1, while supporting Toronto Hydro's continued efforts to modernize its operational systems. The execution of the Program will ensure that Toronto Hydro's EDC continues to withstand evolving hazards and threats, thereby allowing the utility to continue operations and provide customer services, effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers as efficiently and effectively as possible. The following subsections provide further details on the various components as specified above.

Figure 2 illustrates key components within the proposed EDC and its relation to the broader [redacted] all components of the proposed EDC will be secured with [redacted]

[redacted]

1. Physical Infrastructure

To further enhance the resiliency and reliability of the EDC 2 and EDC 1 locations, Toronto Hydro has aligned these locations to the requirements established by the Uptime Institute within its Tier Classification System.[6] EDC 1, [redacted], aligns to Tier I requirements within this classification system and cannot be further enhanced to align to Tier II or Tier III requirements, due to the lack of available space, electrical supply, environmental conditions, and installed redundancy within EDC 1.

With the increased space availability at the location for the proposed EDC, it will be possible for Toronto Hydro to align the proposed EDC with Tier III requirements, meaning that the EDC will be more reliable than the existing EDC 1 and EDC 2 locations by several orders of magnitude, with completely redundant components. Despite the enhanced Tier III functionalities, the utility will build the proposed EDC at a cost that remains proportional to the up-front costs for EDC 2.

[6] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

Key physical infrastructure components within the proposed EDC will include the following:

[redacted]

[redacted]

The increased size of the proposed EDC data hall allows for expanded corridors between EDC assets and provides enhanced physical capacity to install additional equipment in the future. For illustrative purposes, the physical capacity of EDC 2 is shown in Figure 3. By comparison, EDC 1's data hall is already at physical capacity and adding additional infrastructure would require significant reconfiguration of the existing EDC assets.

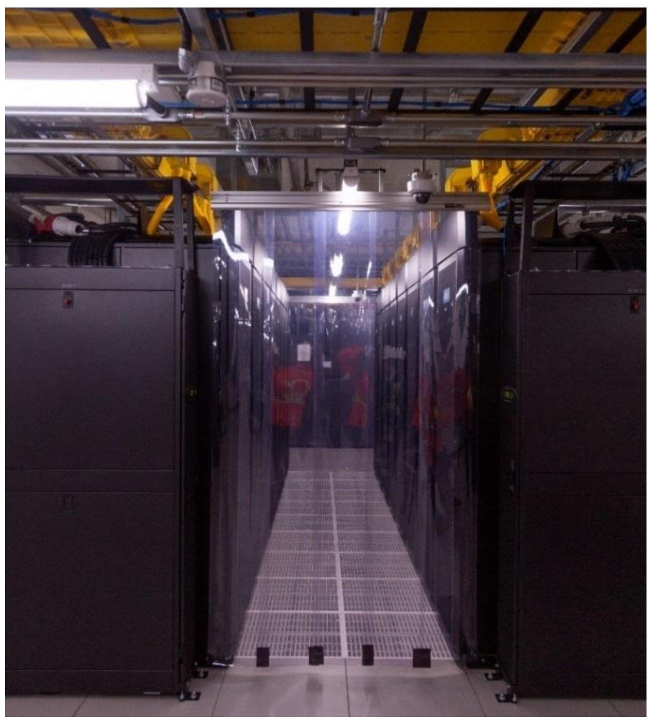


Figure 3: Available Physical Capacity at EDC 2

[7] "ANSI/TIA-942A 2012 Telecommunications Infrastructure Standard for Data Centers", Telecommunications Industry Association, 2012.

2. Electrical Infrastructure

The proposed EDC will have its own dedicated electrical supply points, along with dedicated electrical rooms, UPS and generators. A dedicated 1.25 megavolt-amperes substation will provide power distribution into the EDC. Two dedicated 1.0-megawatt generators will provide enhanced redundancy should an electrical supply failure or upstream outage occur. The dedicated supply points will allow the proposed EDC to remain unaffected by any facilities operations or maintenance activities taking place within [redacted]

Two 550 kilovolt-ampere modular UPS systems will serve the proposed EDC, with each system providing enhanced redundancy, while also being within the secure access perimeter. The size of these UPS systems will be to enable continued growth and allow the proposed EDC to maintain 1:1 redundancy with EDC 2.

3. Mechanical / HVAC Infrastructure

The proposed EDC will contain an advanced HVAC system designed to provide optimal cooling to the overall EDC environment and contained assets. A 24-inch raised floor system will be installed to provide efficient cold air flow panels with flow management capabilities for 20 network cabinets and 64 server equipment cabinets. This HVAC system will leverage free cooling technology to deliver reliable cooling at reduced energy costs when compared to the existing EDC 1. Only the cooling system will be installed within the raised floor system to maximize underfloor space, while the electrical supply will feed EDC equipment from overhead. For illustrative purposes, the underfloor capacity at EDC 2 is shown in Figure 4.

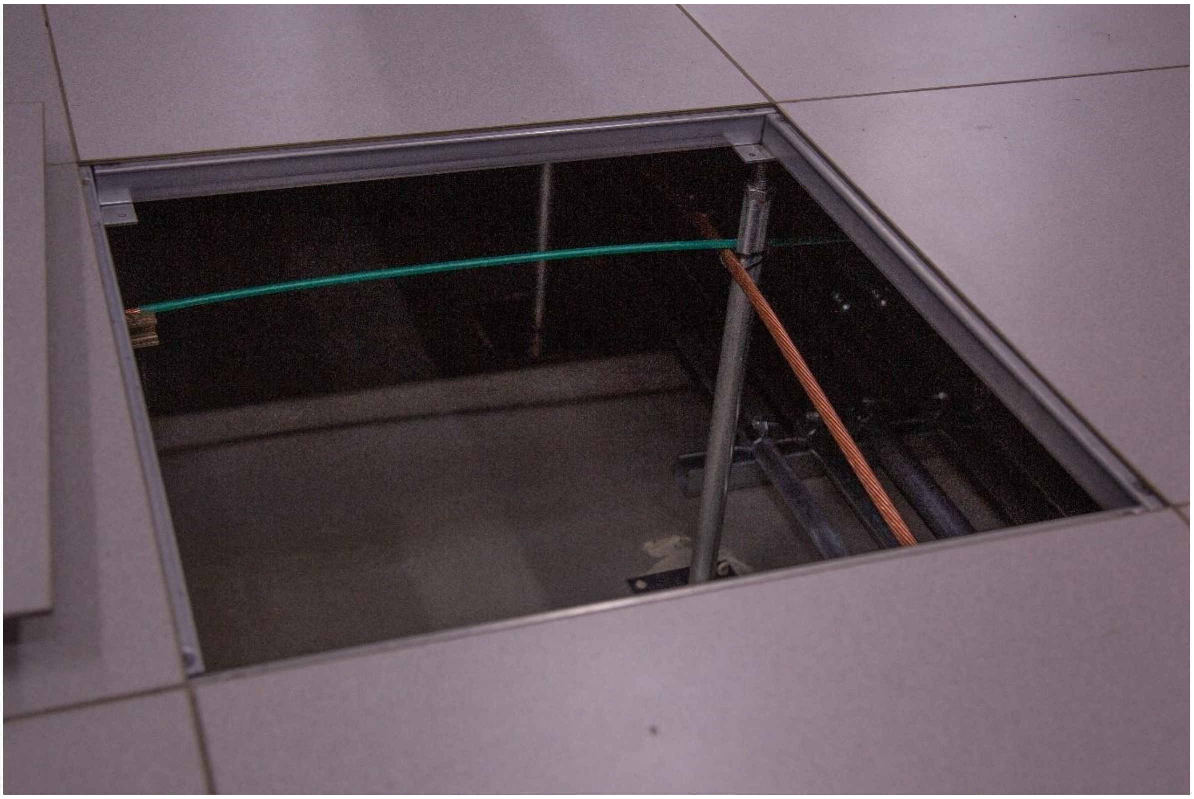


Figure 4: Available Underfloor Capacity at EDC 2

Two CRAC units will be installed within their own dedicated gallery rooms. These units will be stand-alone from the HVAC system and designed to provide redundancy within the proposed EDC. By comparison, the CRAC units within the current EDC 1 are installed directly within the data hall and do not provide redundancy, meaning that if the system fails, there is no backup cooling units available, which may cause the temperature of EDC hardware to increase beyond safe operation limits and result in equipment failure.

An advanced pre-action fire suppression system with sprinkler piping and heads, along with a clean agent gas fire suppression system will be installed within its own dedicated area to provide multi-zone protection within the proposed EDC, including the data hall, CRAC galleries and, electrical rooms.

4. Telecom Infrastructure

The proposed EDC already possesses a fibre-optic connection EDC 2, enabling continuous communications between these two facilities and thereby supporting the 1:1 redundancy across the

EDC. This fibre-optic connection is [redacted], and therefore aligned with industry standards of ten to 50 miles to provide replication data integrity and operational efficiency. By leveraging this existing connection, Toronto Hydro can reduce overall program costs.

5. Network Infrastructure

Network infrastructure within the proposed EDC will be designed to enhance overall disaster recovery ("DR") and reliability by improving end-to-end fault-tolerance architecture, modular redundancy, operational performance, reliability, and availability of enterprise physical Infrastructure. The network infrastructure will be configured to enhance overall scalability capabilities by featuring an optimized architecture designed from the ground up with flexibility and scalability to support the utility's evolving needs.

6. Storage and Backup Infrastructure

All storage and backup infrastructure within the proposed EDC will be on-premises, thereby allowing for data to be retrieved quickly, while allowing compliance with applicable data sovereignty and legislative and regulatory requirements.

7. Computing Resources

All computing resources will be modernized such that they are dynamic and capable of enabling physical connectivity in a scalable manner. Resources will be monitored via real-time monitoring technologies to measure overall performance and respond to emerging risks.

8. Security Infrastructure

The security infrastructure of the proposed EDC will consist of an enhanced security perimeter containing all EDC infrastructure, including the dedicated electrical room, UPS, generators, data hall, staging area, access trap and loading dock, thereby reducing potential safety and security risks.

To enhance overall physical security and control access within the proposed EDC, a multi-step entry system with limited entry points will be configured. EDC access will be based upon dual authentication through card readers and keypads. Access into the data hall, CRAC galleries, staging room, and electrical room will be based upon the card reader system. Access control will be further enhanced via perimeter lighting, thermal cameras, a vehicle security station, and license plate recognition systems to enable employee and vehicle access, as well as incursion protection and video surveillance systems.

E8.1.2.2 Program Drivers

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety, Customer Service, Decarbonization, Financial

1. Operational Resilience

Operational resilience is the primary driver of Toronto Hydro's need to maintain dual EDCs in good condition. A failure of the EDC would result in the immediate interruption of services across the organization that rely on business applications, underlying data, and communication systems. This organization-wide outage, which would include catastrophic disruptions to the previously discussed business processes and operations, would impact overall operational resilience across the organization as further discussed below.

[redacted] As Toronto Hydro's business and operations continue to evolve, the EDC will require more physical and electrical capacity to store and manage more data and to support more enterprise systems and business processes.

In the event of an organization-wide outage due to an EDC failure, the following impacts would immediately arise:

- Reliability impacts: Mission-critical applications that allow the utility to monitor and manage the distribution system, including ADMS and OMS systems would no longer function, eliminating any visibility of the grid. Outages that are already in progress or occur following an EDC failure would be extended indefinitely, until such time that the EDC can go back online;

- Safety impacts: Without visibility of the grid or functioning radio systems, power system controllers can no longer effectively monitor the system, manage planned and reactive outages, or communicate with field crews, giving way to potential safety risks to both crews and the public; and
- Customer service impacts: Toronto Hydro's meter data management ("MDM") systems, customer information system ("CIS") and telephone systems would be unable to function, impeding the meter-to-cash process and the ability of customer care personnel to manage customer service requests.

[redacted] For example, any high-impact renovation and construction projects aimed at improving the work centre assets would require the EDC space to be vacated during the renovations to avoid physical impacts upon EDC infrastructure and vice versa.

[redacted] Over the past five years, these risks and challenges have continued to increase in volume.

Table 4: [redacted] Condition Assessment Results

Item	Condition	Status
Roof	**Very Poor**	[redacted]
Stone Cladding	**Poor**	Performance depends on external conditions.
Windows	**Poor**	[redacted]
Heating & Cooling	**Fair**	Unreliable five-pipe system cannot be replaced without first vacating EDC 1.
Storm Water Piping	**Poor**	Aging stormwater piping must be replaced.
Domestic Water	**Poor**	Aged piping must be repaired.
Sanitary	**Poor**	Aged sanitary system must be repaired.
Electrical Distribution	**Very Poor**	[redacted]
Electrical Service	**Poor**	
Abatement	**Very Poor**	

Examples of asset condition issues within EDC 1 that cannot be resolved due to the risk of materially affecting the integrity of the EDC include the following:

- Building exterior, including masonry and façade issues arising from the [redacted] and deteriorating building envelope and water tightness;
- Deterioration of windows due to age and poor condition, leading to the risk of water infiltration; and
- An aging, unreliable, and corroding five-pipe heating and cooling system that cannot be replaced with a modern duct-based system due to lack of headroom clearance.

In some cases, even smaller initiatives can have larger and broader impacts on EDC 1. For example, shutdowns of EDC 1 were necessary when Toronto Hydro [redacted]

[redacted] This logistical complication increased the costs of installing the new stations.

As the location continues to age and the backlog of high-impact renovations and maintenance activities close to the EDC increase in volume, EDC 1 will impose significant challenges and restrictions in mitigating these asset risks, leading to higher overall costs due to the complexity, effort, and time needed to coordinate the execution of facilities operations and maintenance activities without materially impacting EDC operations. By deferring these high-impact renovations, the utility's operational resiliency will continue to deteriorate over the 2025-2029 rate period.

[redacted]

The previously discussed challenges, combined with the current footprint and asset configuration of the [redacted], render it impossible to upgrade EDC 1 to better align to Tier II or Tier III requirements. Even if Toronto Hydro were to attempt upgrades, it would have to take EDC 1 offline for a significant period of time. This would require all EDC operations to be solely supported by EDC 2 for the duration of the upgrades, which would eliminate the redundancy between the two EDC facilities and unacceptably increase the risk of an organization-wide outage.

2. Reliability

As previously illustrated in Figure 1, the EDC plays a foundational role in supporting all of Toronto Hydro's business applications and processes that are in operation 24/7, including control centre

[8] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

functions, grid management and response, planning and engineering, customer care and billing, and the execution of planned capital work across the distribution system.

A complete EDC failure would result in all of Toronto Hydro's business applications becoming unresponsive and non-functional. In the event of a distribution system outage, this would have cascading and substantial financial and economic impacts on customers within the City of Toronto—the largest city and economic centre of Canada, as well as fourth largest city in North America. During an organization-wide systems failure, customers would have no way of reporting distribution system outages or communicating with the utility due to the disruption to contact centre and communications channels. Due to power losses, commercial customers would face immediate revenue impacts as well as major disruptions to their business operations and harmful side effects, such as the potential spoilage of inventory goods and materials. Industrial customers without available backup systems would see immediate disruptions to their business (e.g. manufacturing) processes and even after power is restored, it would take time for these customers to return to full operations. Critical customers such as hospitals, water pumping stations, emergency management services, or transit operators such as the Toronto Transit Commission ("TTC") would also see immediate disruptions during an organization-wide outage event.

Another reliability factor informing the Program is that EDC 1 is expected to reach its electrical capacity within the next five years due to the limitations of the current UPS system. [redacted]

Finally, EDC resiliency is threatened by increasing vandalism, cyber and physical terrorist threats, and extreme weather event trends. A recently commissioned study conducted by the U.S. Department of Energy has shown an increasing trend since 2015 with respect to vandalism and extreme weather events that are impacting utility-owned infrastructure, as illustrated in Figure 5.[9] As extreme weather and vandalism events continue to grow, both in terms of magnitude as well as frequency [redacted]

[9] U.S. Department of Energy, Electric disturbance events (DOE-417), Archives https://www.oe.netl.doe.gov/oe417.aspx; Toronto Region Conservation Authority, Taking Action on Climate Change in Toronto Region https://trca.ca/climate-change-impacts-gta/

Relocating EDC functions to the proposed EDC will enhance geographic diversity and help mitigate the risk of a single point-of-failure due to an extreme weather, vandalism, or terrorist event.

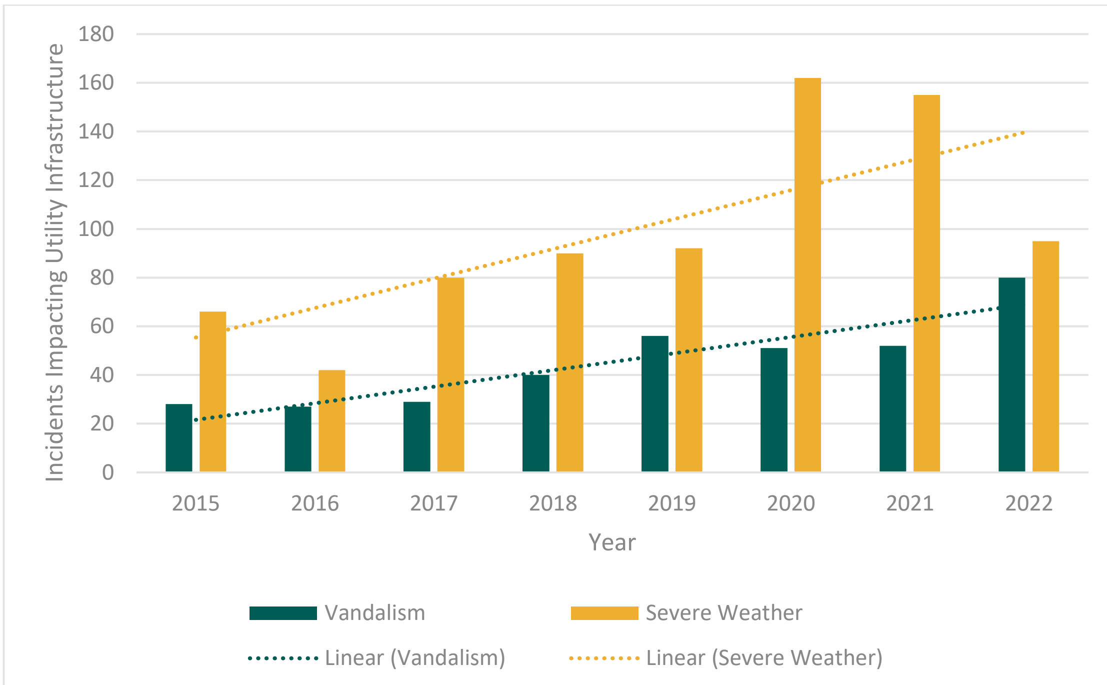


Figure 5: Severe Weather & Vandalism Incidents Impacting Utility Infrastructure

3. Safety & Security

Figure 6 illustrates the supporting systems for EDC 1 that currently reside outside of the secure access perimeter and within common areas of the [redacted] that are exposed to additional safety and security risks. There is also no dedicated or secure location for the storage of EDC assets and spare parts. Only one of Toronto Hydro's UPS units is located within the secure access perimeter of EDC [redacted] Furthermore, EDC 1 does not provide adequate physical capacity for components such as a loading dock, staging area, or access trap. For these reasons, EDC 1 remains exposed to considerable safety and security-related risks. By contrast, as illustrated by Figure 2, all [redacted] EDC components and functions would be fully secure within the secure access perimeter with two-factor authentication, such that only authorized persons can gain access.

[redacted]

4. Decarbonization

As outlined in the Net Zero 2040 Strategy, in Exhibit 2B, Section D7, Toronto Hydro plans to implement several initiatives throughout the 2025-2029 rate period and beyond to reduce the utility's scope 1 greenhouse gas emissions and achieve net zero by 2040. Although Toronto Hydro estimates that it can fully achieve its decarbonization goals for the [redacted], requiring the EDC space to be fully vacated and thus giving rise to the previously discussed risks. Current energy efficiency goals as established by the BOMA and Energy Star are not achievable within the [redacted]

5. Financial

Toronto Hydro's options analysis in section E8.1.4 on page 23 describes the criteria and requirements that the utility assessed to identify the optimal site for the proposed future location for the EDC in light of the high costs of asset management due to the continued risks, challenges, and constraints that are caused by the EDC 1.

E8.1.3 Expenditure Plan

The Program proposes to relocate the existing EDC infrastructure located at Toronto Hydro's EDC 1 to a new location within the proposed EDC to maintain the utility's operational capabilities and mitigate identified resiliency, reliability, safety and security, and decarbonization risks.

The proposed EDC meets all necessary pre-requisites for Toronto Hydro to align to Tier III data centre capabilities as defined by the Uptime Institute.[6] This includes establishing concurrently maintainable capabilities using redundant components and redundant power distribution paths. [redacted] Program costs can be significantly reduced by leveraging this existing connection.

Finally, the proposed EDC is located more than [redacted] away from EDC 2. This provides greater geographical diversity between the two locations, reducing the possibility for a single event (e.g. deliberate attacks, extreme weather) to simultaneously impact both locations at the same time.

Toronto Hydro requires $72 million over the 2025-2029 rate period to execute and complete the Program. This expenditure plan consists of four work categories, namely:

- Non-direct construction costs: Pre-construction planning and equipment expenditures;
- Alterations and demolitions: Costs associated with performing targeted demolitions and alterations within the proposed EDC to support the integration of the EDC;
- Building: Costs associated with facility upgrades needed to meet required standards; and
- Site works: Preparation of the area where the EDC will be constructed.

E8.1.3.1 Planned Project Timeline

The planned project timeline will take place within the 2025-2029 rate period. Planned work and non-direct construction costs will begin in 2025. The construction work will be phased out to minimize any overtime or premium costs and minimize disruptions to business operations. The estimated in-service date for the project is 2029.

E8.1.4 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro has considered the following options to manage the current risks associated with the EDC, including:

- Status quo: Maintaining the EDC 1 and EDC 2 locations in their current state;
- Relocating all EDC functionality to EDC 2;
- Relocating EDC 1 to a non-Toronto Hydro-owned property; and
- Relocating EDC 1 to a Toronto Hydro-Owned Property.

E8.1.4.1 Option 1: Status Quo

The status quo option would entail continuing with the existing EDC 1 as it is configured today, with redundancy being maintained between EDC 1 and EDC 2.

Under this scenario, current risks relating to operational resiliency, reliability, safety and security, and decarbonization would remain in place. Toronto Hydro will be unable to further expand EDC 1, due to current vertical and horizontal footprint limitations and the [redacted] Consequently, EDC 1 will be unable to support a more advanced cooling system to support the introduction of higher density asset infrastructure. Without increases to the density of asset infrastructure, due the utility's reliance on the EDC to process increasing volumes of data and business processes, the UPS of EDC 1 will reach the limits of available capacity over the next five years. This would significantly reduce the efficiency of the UPS in providing sufficient backup power during an outage event and eliminate the 1:1 redundancy between the two EDC locations. In other words, in the event of a failure at EDC 2, EDC 1 could only support a finite number of business applications, meaning that the utility would suffer at least a partial systems outage and incur major business continuity risks.

As major systems within EDC 1 reach end-of-life, the asset management costs to replace or upgrade individual components will increase due to the limited footprint and [redacted] and the unique hazards it presents (such as the presence of asbestos), any cabling or electrical work may lead to delays, cost overruns, and overall higher replacement/upgrade costs.

Due to physical and electrical constraints, EDC 1 can never attain Tier II or Tier III data centre controls and therefore can never provide full redundancy should any of the EDC assets require maintenance or outright replacement. [redacted]

Finally, due to the geographical proximity of EDC 1 and 2, both locations and the EDC infrastructure contained within them could be impacted by a single extreme weather event, natural disaster, threat, or attack. In such a scenario, all functions supported by the EDC would be immediately and adversely impacted and result in operational disruptions and safety risks to Toronto Hydro personnel and potentially to the public. These risks would impede Toronto Hydro's ability to: (a) locate failed assets and affected parts of the distribution system; (b) perform the necessary system isolations to enable crews to safely perform repairs; (c) mobilize crews to affected locations within the system; and (d) remotely control distributed energy resources.

To sufficiently mitigate and manage risks within tolerance levels at EDC 1 while maintaining operations of the current EDC configuration, Toronto Hydro would need to spend approximately $110.4 million, making the status quo option the costliest for the utility.

E8.1.4.2 Option 2: Relocate All EDC Functionality to EDC 2

An alternative option would be to eliminate EDC 1 in favor of having a single EDC operating out of EDC 2. Under this option, Toronto Hydro would entirely shift EDC functionality to the EDC 2 location, which would eliminate the redundancy that currently exists by virtue of the utility's operation of two physically separate EDC locations.

This scenario would also increase Toronto Hydro's risk exposure, as a single disruptive event at the EDC 2 could potentially impact the entire EDC and result in an organization-wide systems outage. Although EDC 2 provides the necessary features and footprint to support continued growth of the EDC and enable the attainment of Tier II data centre controls, the lack of geographical redundancy would nonetheless significantly expose the utility to the risk of weather-related events, natural disasters, and deliberate threats.

As this scenario would leave the single EDC excessively vulnerable to a variety of risks and the costs to mitigate these potential risks would be too high, the utility does not consider this to be a feasible option.

E8.1.4.3 Option 3: Relocating EDC 1 to a Non-Toronto Hydro-Owned Property

In developing the Program, Toronto Hydro also assessed whether alternative real estate and construction configurations may result in greater cost savings. For example, one alternative would be the relocation of EDC 1 to a location outside the city of Toronto, where real estate costs are significantly lower. The utility further evaluated whether it would be feasible and cost-effective to replace the on-premises EDC 1 with an entirely cloud-based solution.

1. Relocating EDC 1 to a Location Outside of Toronto

Toronto Hydro assessed potential cost-saving opportunities from relocating EDC 1 to a location that is outside of Toronto, where real estate and development costs would be lower than in the city of Toronto.

The major challenge posed by this approach would be maintaining the 1:1 redundancy between the relocated EDC and EDC 2, which is currently achieved [redacted] at a location outside of Toronto Hydro's service area would be extremely costly, due to the larger distances required to secure this connection. These additional costs would likely offset any savings achieved in real estate and/or development costs. To install this [redacted], Toronto Hydro would also be required to coordinate with the utility that is managing the adjacent service area. This level of coordination and approval may result in greater project delays and cost overruns.

As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are shared resources and infrastructure with respect to cabling pathways, physical security & access control solutions, as well as power redundancy solutions that can be extended to the proposed EDC location, there are enhanced benefits in moving the EDC [redacted].

Distance also becomes a key parameter in disaster response. For example, employees would have to travel large distances to potentially inaccessible locations to provide emergency and disaster responses. This is not safe or ultimately reliable for employees. When considering these constraints as well as the additional costs, this option is not considered to be feasible or viable for Toronto Hydro.

2. Development of a Cloud-Based Control Operations Systems Centre

Toronto Hydro's EDC 1 is [redacted]

As discussed in Toronto Hydro's Information Technology Asset Management and Investment Planning Strategy in Exhibit 2B, Section D8, the availability of cloud-based solutions, where a third-party provider can manage the servers and perform the maintenance and security updates supporting a business function or software platform, is steadily increasing. Cloud-based solutions are also available in the form of "private clouds", where all cloud computing resources remain exclusive to a single client. However, the cost structure of cloud-based data centre hosting would be significantly different than implementing an [redacted], as vendors typically charge for cloud solutions on an ongoing, monthly basis. In other words, the implementation of a cloud solution would introduce new operational, maintenance, and administrative ("OM&A") costs for Toronto Hydro that over time would exceed the up-front capital expenditures that are proposed under this program and reduce the cost effectiveness of this option.

Furthermore, the implementation of a cloud-based solution—even a "private" one—would introduce several reliability or operational risks that would not exist under an on-premises solution. Toronto Hydro would have to rely upon its vendor(s) to manage the reliability of the cloud-based environment or restore functionality after planned downtimes or unplanned outages, in contrast to an [redacted]. This would increase reliability and business continuity risks with respect to the critical functions performed by the EDC. Many of the business applications supported by the EDC, particularly those that are critical for Control Centre Operations,[10] would be better served by an [redacted] that would better meet the latency and communications parameters required for the underlying functions.

In addition, several traditional hard-wired components that are directly supporting the EDC and its connectivity with the field asset infrastructure, including fibre-optic connections, would not be

[10] Exhibit 4, Tab 2, Schedule 7.

compatible with cloud-based services. Given the collective risks presented by the above factors, Toronto Hydro determined that a cloud-based solution would not be feasible option.

E8.1.4.4 Option 4: Shifting EDC 1 to a Toronto Hydro-Owned Property

The fourth and final option involves relocating EDC 1 to an existing property already owned and operated by Toronto Hydro and within Toronto Hydro's service area. Relocating EDC 1 to an alternative Toronto Hydro location would introduce cost savings by utilizing existing footprints and building systems in place. The subsequent sub-sections will individually examine potentially viable locations to assess the feasibility of relocating the EDC functions.

3. Relocating EDC 1 to [redacted]

Toronto Hydro's operations [redacted] Unlike the proposed EDC, the [redacted] does not possess the necessary square footage to house all EDC assets. In addition, there is no current fiber-optic connection with EDC 2, to maintain the 1:1 redundancy between the EDC locations. While a fiber-optic connection can be installed between these two locations, it would considerably raise the overall costs for the program. As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are [redacted], there are enhanced benefits in keeping both EDC locations close to the existing Control Centre facilities [redacted] For these reasons, the [redacted] is not considered to be a prudent, cost-effective option.

4. Relocating EDC 1 to the Proposed EDC (Selected Option)

Toronto Hydro's operations [redacted]. As is the case with the [redacted] the proposed EDC has the necessary footprint and characteristics to support the development of a Tier III data center solution, as defined by the Uptime Institute. As there are cost-savings opportunities by leveraging shared resources and infra structure, including cabling pathways, physical security & access control solutions as well as power redundancy solutions that can be extended to the proposed EDC location, there are en hanced benefits in moving the EDC to [redacted]

Cost savings are further achieved as the proposed EDC [redacted], which is needed to maintain 1:1 redundancy between the two EDC locations. This current-state connection is further illustrated in Figure 7. The [redacted] possesses a total of [redacted] square feet of space to accommodate a fully functioning EDC with all required assets. Ultimately, when taking into consideration costs, footprint and building characteristics, [redacted] remains the sole option that meets all requirements and cost considerations.

[redacted]

E8.1.4.5 Evaluation of Options

Toronto Hydro selected a set of evaluation criteria to compare each available option, and identify the most optimal, cost-effective, and prudent option for this program. Evaluation criteria included the following:

- Environment (humidity, moisture/condensation, extreme floods, ice storms, etc.);
- Space for EDC footprint;
- Space for EDC generators;
- Prerequisites to meet Tier III requirements as defined by Uptime Institute;
- Geographic diversity (the longer the distance between the two EDC locations, the better);

[redacted]

- Proximity to Existing Control Centre; and
- Total Cost Impact to Ratepayers.

Each of the above criteria were taken into consideration when selecting the best overall option for Toronto Hydro.

Figure 8 illustrates the results of the options analysis, comparison, and final recommendations, based upon what has already been discussed for each of the options above.

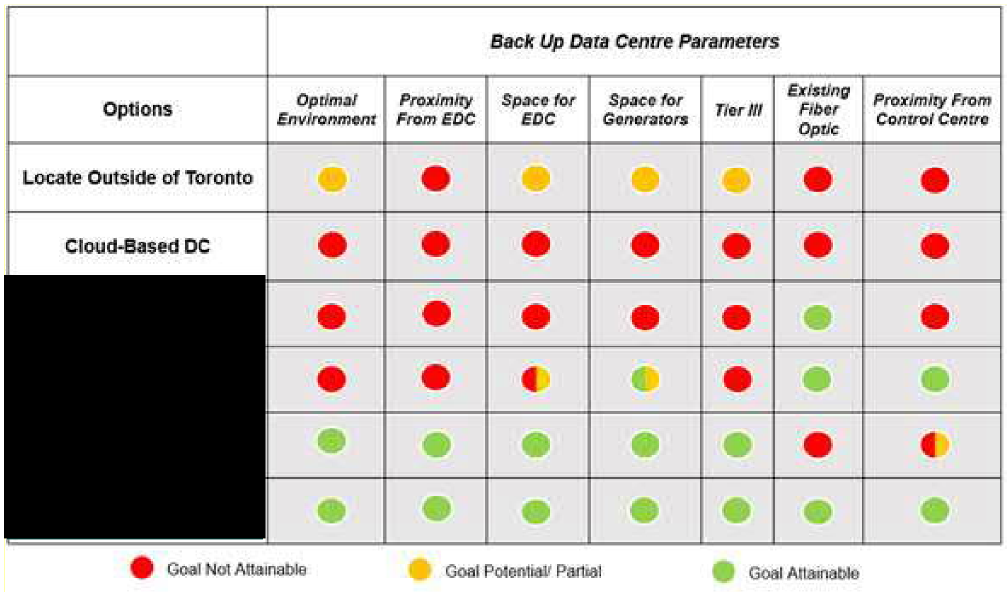


Figure 8: Results of Option Analysis

When assessing current-state risks, availability of space and technological capabilities, costs, as well as overall ability to meet the current and future objectives for the EDC, this comparison indicates that the relocation of EDC 1 to the proposed EDC satisfies all the criteria. Ultimately, relocating the EDC to the proposed location is the most effective and prudent solution to satisfy all requirements for this program.

E8.1.5 Execution Risks & Mitigation

The largest risk to the successful execution of the Program involves timing and costs. Material costs are generally subject to greater price fluctuations over time and therefore cost overruns may transpire. However, through the expertise of experienced project management leadership and industry experts, a proactive approach will be taken to manage these costs.

In addition, there are also construction related risks associated with the Program, including:

- Unexpected construction conditions;
- Occupational health and safety;
- Disruption to Toronto Hydro employees at [redacted];
- Design change approvals;
- Budget shortfalls;
- City approval delays;
- Procurement / Tender delays; and
- Design changes.

These issues can be mitigated with proper communication, leveraging the expertise of the consultants and proper project planning. Overall, leading project management tools and practices will be utilized, and the expertise of highly qualified project management leadership and industry experts will be leveraged to take a proactive approach to managing unknown conditions.

Toronto Hydro's Facilities Asset Management Strategy (filed at Exhibit 2B, Section D6) has established a strong foundation to ensure that these potential planning and execution risks will be mitigated accordingly.

E8.2 Facilities Management and Security

E8.2.1. Summary

Table 1: Program Overview

2020-2024 Cost ($M): 85.1	**2025-2029 Cost ($M):** 145.5
Segments: Facilities Management and Security	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Safety, Operational Effectiveness - Reliability, Financial Performance, Environment	

Through the Facilities Management and Security Program (the "Program"), Toronto Hydro invests in building improvements that are critical to the operation of the utility's electricity distribution system, demand-driven projects that support the utility's decarbonization objectives, and the ability to modernize its business processes in accordance with the evolving needs and nature of its customers. The facilities owned by Toronto Hydro and covered by the Program include four work centres that have unique footprints and functions, along with 185 stations that serve a critical role in operating the utility's distribution system.

The Program's primary objective is to maintain the infrastructure that supports critical operations of Toronto Hydro's distribution system and replace assets that are end of life and in poor or critical condition. These assets pose an increased risk of failure, which results in an increased risk of business interruption and the deterioration of key outcomes such as safety, reliability, customer service, and productivity. The Program also supports the management and maintenance of Toronto Hydro's buildings in accordance with the growth and evolving needs of the distribution system.

The Program is comprised of the following three areas:

1) **Stations**: Includes investments and improvements to build and maintain the facilities that house Toronto Hydro's distribution stations and manage risks that may arise from any facilities assets deteriorating to the point of poor condition or end of life. As the integrity and operating conditions of stations buildings may significantly affect safety and the reliability of distribution equipment housed within, these assets are critical to grid safety and performance.

2) **Work Centres:** Includes repairs to the facilities that provide a work space for Toronto Hydro personnel and also serve as storage and parking spaces for the utility's equipment, materials, and vehicle fleet. The utility's four work centres are located in the city of Toronto at 14 Carlton Street, 500 Commissioners Street, 71 Rexdale Boulevard and 715 Milner Avenue. The primary function of investments in this area is to minimize safety risks to utility personnel, visitors, and the general public and ensure productivity by replacing poor condition and end of life assets that may otherwise cause hazards or business interruptions. This area also includes investments that support the utility's strategic objectives and outcomes, such as the modernization of business processes in accordance with the evolution of customer expectations and distribution services, and investments to decarbonize in line with Toronto Hydro's Net Zero 2040 Strategy in Exhibit 2B, Section D7.
3) **Security Improvements:** Includes investments in security enhancements at Toronto Hydro's facilities that are necessary to protect the safety and security of employees, assets, and the public. These investments include up-to-date security equipment and technologies. Toronto Hydro also plans to upgrade its preventative security measures to reduce the risk of trespassing, theft, injuries, and cybersecurity attacks.

The Program is a continuation of the activities described in Toronto Hydro's 2020-2024 Rate Application,[1] embodying the utility's Facilities Asset Management Strategy (the "AM Strategy") in Exhibit 2B, Section D5, as well as applicable industry standards, such as ISO 55001. The utility relies on the AM Strategy to manage assets in a cost-effective manner and in order to ensure that facilities remain safe and functional. As discussed in the AM Strategy, the asset condition assessment process determines both a) the risks that may be present in respect of facilities assets and b) plans to mitigate these risks. This assessment and risk management process is a significant part of the planned scope of work for the 2025-2029 rate period. Without sufficient funding to make these investments, Toronto Hydro's facilities would be exposed to the risk of structural failures and significant hazards and/or damage, e.g. due to flooding or leaking. If these risks were to materialize, they would cause severe disruption to the utility's business activities and potentially prolonged outages.

The Program coordinates evaluation and repair work in order to efficiently plan and execute projects. The utility internally coordinates a) its evaluation of a given asset with surrounding asset conditions and its future planned work, and b) capital work on the distribution system, outlined in in the Stations

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Section E8.2.

Renewal (Exhibit 2B, Section E6.6), to align planned facilities projects with distribution projects. For example, if a building requires basement and foundation work, the Program evaluates if other scopes of work can be included at the same time, such as introducing a leak detection system, a sump pump system, or other plumbing refurbishment when the concrete is being removed and trenching can readily take place. Grouping projects together minimizes disruption to stations operations, reduces the potential impacts of the work on customers, and helps the utility manage costs more effectively.

Figure 1 below outlines some examples of stations and work centres. Table 2 outlines some high-level statistics of Toronto Hydro-owned properties.

Figure 1: Examples of Toronto Hydro infrastructure; a downtown substation and work centre.

Table 2: Toronto Hydro Stations Properties Statistics

Category	Quantity
Average Station Property Area	6,200 sq. ft.
Stations Properties above 50,000 sq. ft.	12
Heritage Stations Properties	8
Stations Properties over 40 Years Old	165

1 ## E8.2.2. Program Outcomes

2 **Table 3: Outcomes and Measures Summary**

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives by: ○ Ensuring compliance with applicable legislative and regulatory requirements, such as the Occupational Health and Safety Act2, Ontario Regulation 851: Industrial Establishments3, the Ontario Building Code4 and the Fire Code5; ○ Providing the utility's employees safe and functioning work centres by repairing deficiencies that may cause hazards; ○ Addressing stations related deficiencies such as the absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; and ○ Improving internal lighting conditions and repairing external damaged lighting in work areas. ○ Installing enhanced safety systems to deter theft, vandalism and violence towards employees, and reduce the risk of unauthorized access into work centres and stations.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's network reliability objectives and ensures compliance with applicable legislative and regulatory requirements such as the Ontario Energy Board's Cyber Security Framework6 by: ○ Implementing, maintaining and managing modern commercial security systems and technology in partnership with security subject matter experts; ○ Applying security management policies and procedures across all Toronto Hydro sites; ○ Investing in building-related improvements at stations and work centres that are critical to the operation of Toronto Hydro's distribution system; ○ Mitigating the risk of damage to critical distribution equipment housed within the stations; and

[2] Occupational Health and Safety Act, R.S.O. 1990, Ch O.1.
[3] Occupational Health and Safety Act, R.R.O. 1990, Reg. 851: Industrial Establishments.
[4] Building Code Act, 1992, S.O. 1992, c. 23, O. Reg 332/12.
[5] Fire Protection and Prevention Act, 1997, S.O. 1997, c. 4, O. reg 213/07.
[6] Ontario Cyber Security Framework, 2017.

	○ Prioritizing preventative maintenance of assets that are end of life or in poor condition to mitigate against costly reactive repairs.
Financial Performance	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Using the AM Strategy (filed at Exhibit 2B, Section D6) to optimize assets' capital and operational costs in line with the condition assessment ○ [check workplace consolidation relationship with total efficiency]
Environment	• Contributes to Toronto Hydro's environmental objectives and enables the goals outlined in utility's Net Zero 2040 Strategy (filed in Exhibit 2B, Section D7) by reducing greenhouse gas ("GHG") emissions through: ○ Electrification of building operation systems such as replacing natural gas heaters with air-source heat pumps

E8.2.3. Program Drivers and Need

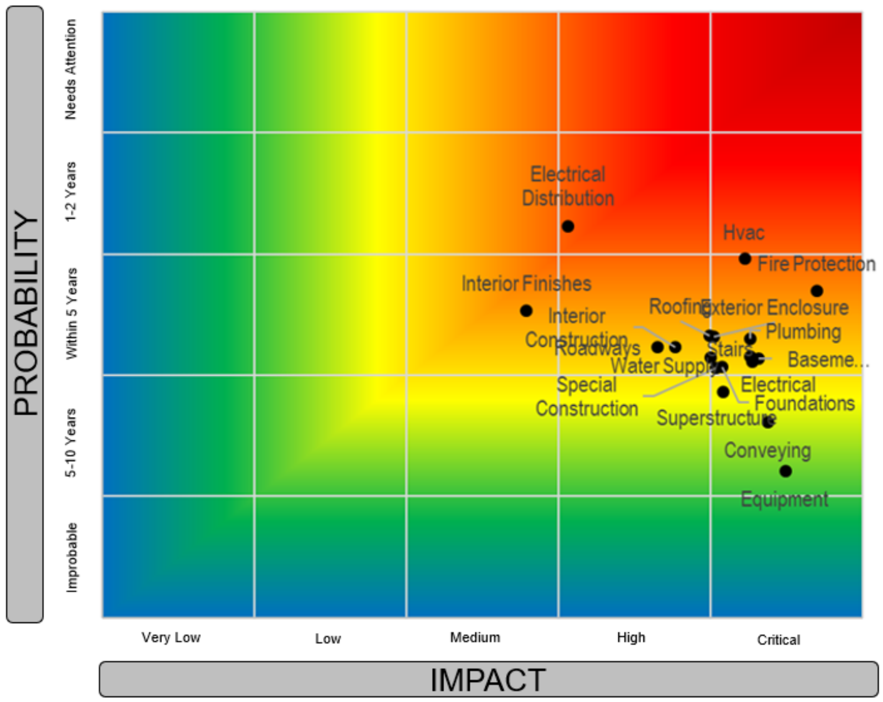
Table 4: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety and Failure Risk

The Program prioritizes investments that address assets at end of life and in poor condition, in line with the AM Strategy and Toronto Hydro's objectives to operate and maintain a safe and reliable distribution system. The utility evaluates the condition of building assets pursuant to the AM Strategy.[7]

Figure 2 below illustrates the relationship between the probability and impact of failure for the various building systems according to the Uniformat II framework, as discussed in the AM Strategy. The probability and impact measures are an output of periodic building condition assessments. Understanding the relative risk associated with each of the building systems allows Toronto Hydro to efficiently allocate capital funding to the areas that provide the best value and address the greatest risk.

[7] Exhibit 2B, Section D6, at pages 3-4.



1 **Figure 2: Likelihood-impact matrix for UNIFORMAT II building elements as of 2023**

2 ### E8.2.3.1 Categories of Facilities Work

3 **Table 5: Types of Program Projects Planned for the 2025-2029 Rate Period**

Project Category	Rationale	Risk of Failure
Structural & Envelope (e.g. repairs to the building envelope and façade, windows, foundation and structural elements, beams, joists, columns, etc.)	Addresses safety issues and prevents structural damage of critical supporting functions and deteriorated building performance.	If a structural element were to fail and damage distribution equipment, significant and prolonged outages could occur.

Project Category	Rationale	Risk of Failure
Architectural & Interiors (e.g. roofs, doors, building finishes, office work areas, etc.)	Addresses safety issues and building water-tightness, and promotes optimal building performance.	If a building asset or system failure were to expose interiors to the elements (e.g. water infiltration), distribution equipment could be permanently damaged, costly business interruptions could ensue and hazards may exist to workers and the public.
Fire & Life Safety (e.g. stations fire alarm system upgrades, signage and emergency lighting, etc.)	Replaces obsolete fire alarm systems and addresses safety and compliance issues.	Deficient or lacking fire and life safety systems and assets may endanger employees due to hazards from fire and harmful gases, and also put equipment at risk of damage or destruction, thereby increasing the risk of outage.
Mechanical, Electrical & Plumbing (e.g. HVAC system replacements, supplementing cooling systems, upgrading and replacement of lighting, sump pump replacements, plumbing fixtures, hot water tanks, etc.)	Addresses assets in poor condition, equipment overloading and capacity issues, safety concerns, and achieves compliance with mandated requirements.	Failures of these types of assets and systems may cause damage to equipment (e.g. in the event of flood in basements) or cause operational disruptions and a loss of productivity (e.g. in the event of loss of power).
Civil & Sitework (e.g. exterior access ways and walkways, including pavement, driveways, and parking spaces, etc.)	Addresses safety and security-related concerns.	Deficiencies in assets could cause safety risks (e.g. trip and fall hazards) for employees and the public. Furthermore, deficient or lacking features (e.g. doors that do not properly lock) could result in security risks such as theft, vandalism, or unauthorized access.

1. Structural & Envelope

Structural features are those supporting a building. Envelope features are those that separate a building's interior from its exterior. The integrity and operating condition of a building's structural and envelope features are critical to keeping Toronto Hydro's distribution system reliably operational and ensuring the safety of employees and the public. Structural and building envelope components cannot run-to-fail because one beam or column failure can result in a full building failure, leading to potentially catastrophic safety and reliability risks and significant operational disruptions.

The sections below outline some planned structural and envelope repairs and refurbishments for assets in a deteriorating state. These sections provide the categories of planned work on station assets and the rationale for each type of investment.

a. Structural

Toronto Hydro plans to address issues related to the foundation and supporting structural elements (e.g. beams, joists, and columns) within work centres and stations, including two downtown station structural refurbishments.

Figure 3: Examples of structural deterioration at stations, from left to right: Wiltshire Station exposed and corroded rebar with significant water infiltration, Wiltshire Station exposed rebar in concrete wall.

Figure 4: Examples of structural deterioration at stations, from left to right: Windsor Station cracked concrete floor slab, Windsor Station corroded rebar columns.

Figure 5 provides examples of aging structural assets where deterioration can occur more rapidly and in a greater number of locations when water infiltration is present.

Figure 5: Examples of structural deterioration at work centres, from left to right: 500 Commissioners Building C – spalling concrete wall with preventative netting; 500 Commissioners Building C – exposed deteriorated waterproofing; 500 Commissioners Building C – rusted steel staircase.

b. Envelope

Toronto Hydro plans to address issues related to end of life building envelope elements such as exterior cladding, windows, and roofing systems to protect critical equipment from weather. The utility's envelope investments in stations' window upgrades and increased façade insulation will advance the utility's objective to reduce its facilities' GHG emissions by increasing energy efficiency

Figure 6: Examples of envelope deterioration at stations, from left to right: Glengrove Station concrete block wall cracking, Duncan Station brick wall cracking, Junction Station brick wall cracking.

Figure 7: Examples of envelope deterioration at work centres, from left to right: 500 Commissioners Building A – cracking of precast panels at the Control Centre; 14 Carlton – deteriorated windows, sealant, and frame.

2. Architectural & Interiors

The architectural system and interiors of a building comprise a building's core systems, including the roof, doors, floor plans and wall partitions, and interior finishes and furnishings.

a. Architectural

Toronto Hydro must proactively and preventatively invest in architectural repairs to maintain the integrity of its stations portfolio. When structural damage is unearthed once damaged waterproofing is removed from a station, the utility typically pairs architectural repairs to waterproofing systems with structural repairs of the underlying building assembly and structure. Other architectural items that require repair or maintenance to ensure worker safety are fire rated enclosures, egress systems, and exits.

Figure 8: Examples of architectural deterioration at stations, from left to right: George and Duke Station deteriorated concrete stairs, Centre Drive Station water infiltration from roof.

Figure 9: Example of Terauley Station, replacing non-code-compliant stairs and railings with functional ones, and improved dock access.

b. <u>Finishes</u>

Within the utility's stations portfolio, Toronto Hydro plans to address issues related to buildings' interior finishes that directly impact user safety. As examples, certain lighting standards are required to keep buildings at an acceptable level of brightness. Furthermore, deteriorated flooring and stair treads can cause tripping hazards. Maintaining, repairing, and replacing these finishes provides a safe and accessible workplace for the employees who interact with the utility's stations.

Within the utility's work centres, Toronto Hydro plans to address issues related to the building interior finishes (e.g. coatings, carpets, workstations and office furniture) where existing materials are end of life or in poor condition and where assets no longer meet the needs of the utility's workforce. As examples, improving the working condition of some finishes will promote employee safety, such as lighting standards to keep buildings at an acceptable level of visibility, and mending deteriorated carpet and flooring will help reduce the risk of tripping hazards. Furthermore, maintaining finishes at a reasonable standard prevents the need for significant renovations to address cumulative deterioration.

3. Fire & Life Safety

Fire and life safety systems, including fire suppression, alarms, and preventative equipment, protect workers in the event of fire or environmental hazards and are essential to building, staff, and public safety.

Stations without functioning life safety or fire alarm systems are a high priority investment. The Program will continue work that the utility commenced in the 2020-2024 rate period work to replace outdated fire alarm panels. As of 2023, Toronto Hydro upgraded five (5) panels to a current and compliant fire panel system during the current rate period.

It is safer and less expensive to proactively repair and replace fire and life safety systems. If a fire alarm device is in a state of disrepair, the utility must hire fire watch personnel for patrol until the fire alarm system is back online. The cost of hiring a 24/7 fire watch for a device is prohibitive if the fire watch must be in place for days or weeks until a part is shipped for the alarm repair or replacement. This type of reactive response incurs significantly higher costs than a proactive repair and replacement program.

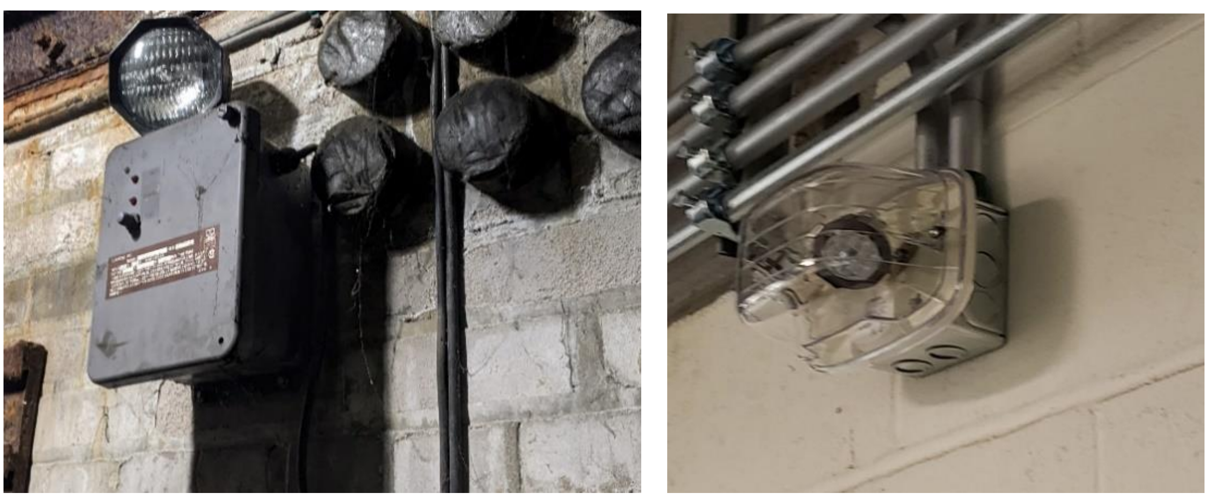


Figure 10: Example of Terauley Station, replacing non-compliant emergency lighting (left) with functional and compliant lights (right).

Within work centres, the 500 Commissioners work centre has aging dry sprinkler systems and faulty water systems that require maintenance and repair. A side benefit of modernizing and improving the condition of these systems would be to reduce nuisance alarms that disrupt work at work centres.

[redacted]. Reducing the incidence of false alarms triggered by faulty systems would alleviate this risk. Furthermore, by implementing modern systems like two-stage alarms, fire alarms and evacuations can target localized building zones and minimize the disruption to critical control operations.

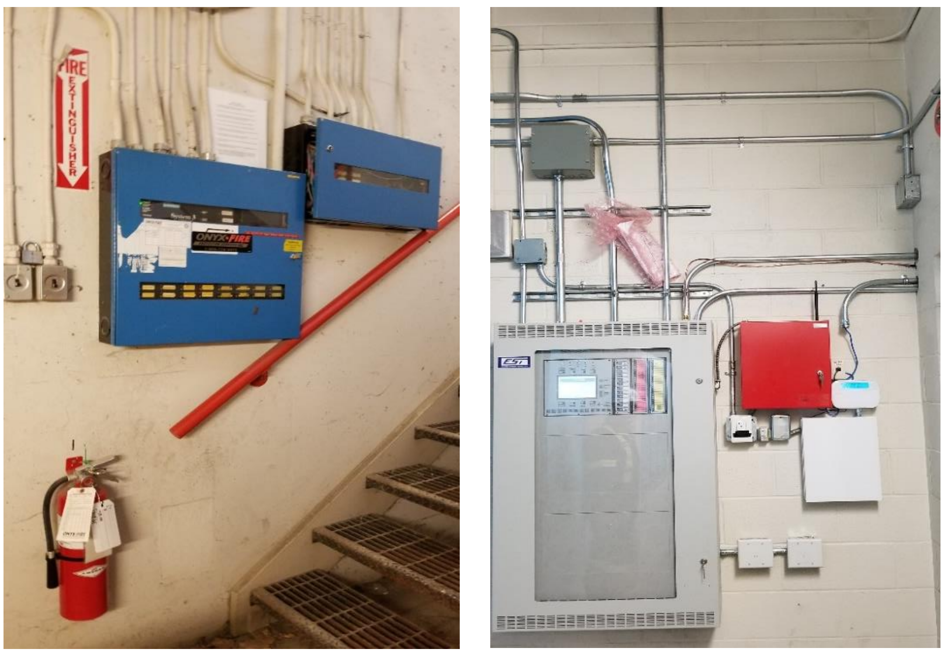


Figure 11: Example of Esplanade Station outdated fire alarm panel (left) with a new, functional panel (right).

4. Mechanical, Electrical & Plumbing

Mechanical and electrical assets include plumbing, heating, ventilation and air conditioning ("HVAC") systems, site lighting, electrical panels, electrical wiring, building automation systems, and power distribution systems in Toronto Hydro's buildings.

These systems are critical to reliable operation of the utility's work centres and stations buildings. Toronto Hydro plans to replace end of life infrastructure and equipment, including cooling systems for critical equipment in stations, to improve reliability on high temperature days and prevent disruptions or outages due to overheating equipment. The utility also plans to make investments in plumbing and emergency sump systems and other infrastructure to reduce the risk of asset failures and damage to equipment, which may disrupt grid operations.

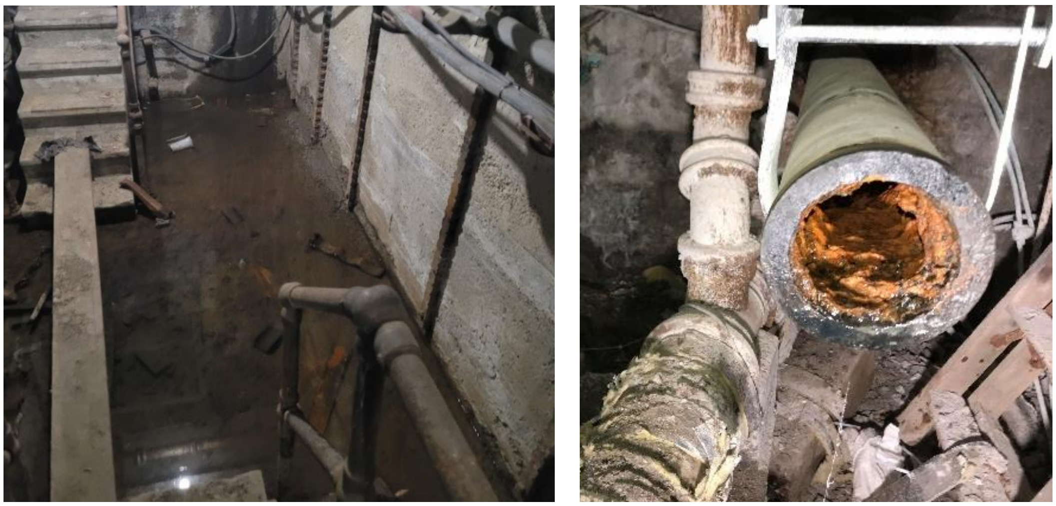


Figure 12: Examples of mechanical and plumbing deterioration at Stations: Terauley Station with a flooded basement and Terauley Station water service line clogged and full of debris.

Figure 13: Examples of HVAC additions at Stations: Strachan Station without additional air conditioning (left) and after with two new condensing units installed for keeping air temperature and equipment cool (right).

Figure 14: Examples of HVAC additions at Stations: Cavanagh Station without additional air conditioning (left) and after with ducts and venting installed for keeping air temperature and equipment cool (right).

5. Civil & Sitework

Property civil work and sitework includes work related to exterior access ways and walkways, pavement, driveways, parking spaces, and exterior lighting. A variety of investment and maintenance needs are present in this area. Certain exterior surfaces at work centres and stations are in poor condition and need repair to prevent tripping hazards, pot holes, delamination, and water ponding. Exterior lighting at certain stations is currently inadequate for response crews' ability to work safely. Additional paving is required to accept multiple trucks on site at several stations as a need for operational efficiency.

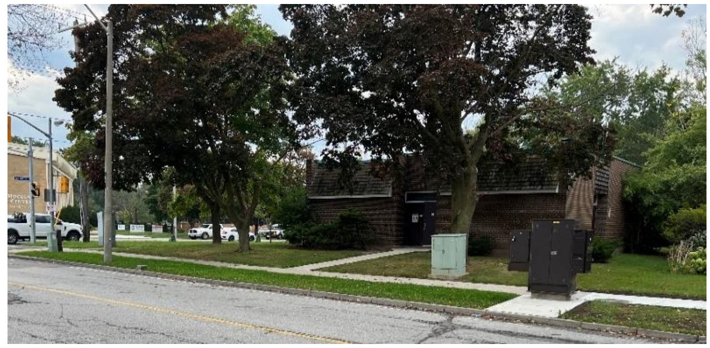



Figure 15: Examples of driveway deficiencies at Stations: Hunting Ridge Station driveway in disrepair, Longfield Station with no available parking for response crews.

E8.2.3.2 Stations

Toronto Hydro's investments over the 2025-2029 rate period will focus on stations. Approximately 50 percent of the planned work will address stations assets and infrastructure. Figure 14 below highlights some examples of stations with poor quality structural assets. Deterioration at this level indicates that the structural system has operationally lost its serviceability for the actual service load that the structure is subjected to and presents a high risk to occupant and equipment safety. To mitigate the risk of partial or complete building collapse that may ensue from these conditions and prevent significant damage to distribution equipment or catastrophic safety risks to employees and the public, the utility must address these deficiencies in a timely and effective manner.



Figure 16: Examples of existing stations in critical condition, from left to right: George and Duke Station, beam with exposed rebar, Defoe Station cracked beam, Junction Station deteriorated foundation wall.

Toronto Hydro's portfolio includes large-footprint stations, stations on heritage sites, and stations integrated into residential neighborhoods. To address stations-related issues, the utility must tailor specialized design and investment plans to each station's features and condition. These investment plans consider asset age, site condition, priority, probability of failure, and impact to yield a system criticality rating.

E8.2.3.3 Work Centres

1. Overview

In addition to investments to maintain, repair, and replace assets as discussed above under subsection E8.2.3.1, Toronto Hydro plans to invest in work centres in accordance with its strategic outcomes and objectives. Work centres house Toronto Hydro employees and provide a physical space to operate the business. Employees have functional workplaces that enable them to provide quality service to customers. As the nature and needs of customers evolve and the utility invests in growing its distribution system and modernizing its business processes in response, it also must have adequately furnished work centres for employees to execute work and provide customer service. Approximately 35 percent of the planned work in the Program is related to work centres.

The volume of asset management work required at work centres over the 2025-2029 rate period is lower compared to the Stations segment, with three of the four work centres being relatively new (having been built or retrofitted within the last few decades) and in good operating condition.

Key work centre-specific initiatives include:

- **Work Centre Decarbonization:** targeted projects that will decrease GHG emissions from Toronto Hydro's work centres; and
- **Work Centre Modernization:** select improvements to office workspaces that support the future of collaborative and flexible work, and efficiently use office areas.

2. Work Centre Decarbonization

The Program includes investments to decarbonize work centres in alignment with the utility's Net Zero 2040 Strategy.[8] Toronto Hydro's Customer Engagement showed that a majority of the utility's

[8] Exhibit 2B, Section D7.

customers indicate general support for investments that reduce Toronto Hydro's environmental impact.[9]

Toronto Hydro will phase the timeline for decarbonization investments, starting in the 2020-2024 rate period and continuing through the 2025-2029 rate period and beyond, until Net Zero targets are achieved by 2040. The utility will execute these investments in a balanced manner to achieve decarbonization objectives while maintaining costs at a reasonable level and minimizing the risk of stranded assets and business interruptions.

Toronto Hydro's decarbonization investments in the 2025-2029 rate period will focus on assets that are at end of life to avoid stranding assets. The utility will engage in fuel switching by replacing selected fossil fuel-powered assets identified with electric assets to prudently deliver a high level of decarbonization proportionate to project costs. The utility will concurrently make investments in building efficiency, building automation systems ("BAS"), and other building envelope measures to improve the energy efficiency of its work centres, which will reduce overall energy use and require fewer electrified assets for heating and cooling work centres.

The three main investment streams targeting GHG emissions at work centres will consist of:

1. **Fuel Switching (Eliminate Scope 1 Emissions)**: replacing natural gas- or other fossil fuel-powered equipment with electric assets.[10]
    a. GHG emissions from natural gas heating accounted for majority of all of the utility's GHG building emissions in 2022.
    b. Toronto Hydro will target aging and/or poor condition natural gas equipment minimize stranded assets.
2. **Improve Building Efficiency (Reduce Scope 2 Emissions)**: improving energy performance to reduce buildings' electrical loads.
    a. In conjunction with eliminating GHG emissions from fossil fuel-powered equipment, Toronto Hydro will reduce the electrical load of its buildings through efficiency measures, which would further reduce GHG emissions associated with line losses

[9] Exhibit 1B, Tab 5, Schedule 1

[10] Scope 1 emissions are direct GHG emissions that occur from sources controlled or owned by an organization. Scope 2 emissions are emissions that an organization causes indirectly and that come from where the energy it purchases and uses is generated. Scope 3 emissions are emissions that are produced by an organization's value chain, and not as the result of an organization's assets or activities. This program does not address measures to reduce the organization's Scope 3 emissions.

from the utility's consumption of electricity delivered through transmission and distribution grids.

b. Building Automation Systems ("BAS"): BAS provide a centralized control system for a building's facilities systems, including electrical and mechanical (heating, ventilating, air conditioning) systems, which provides both visibility and control of the building's operations and performance, ensuring harmonious and efficient operations according to occupant requirements. Part of the investments will add legacy and new equipment to the BAS network.

c. Envelope Improvements: identifying areas with air leakage and implementing appropriate repairs reduces unnecessary heating and cooling, and lowers the demand on building operation. Intensive envelope improvements include façade retrofits and roof repairs. Although these retrofits and repairs are standard maintenance for aging buildings, Toronto Hydro's investments will enable increased insulation above minimum code requirements to retain heating and cooling more effectively, lowering energy consumption.

3. **Additional Improvements (Reduce Scope 1 & 2 Emissions):** other improvements to building operation efficiency.
   a. Adding two cooling setpoints to air conditioning units that allow high operation on hot days and low operation on more frequent mild days.
   b. Providing additional CO_2 sensors to act as occupancy monitoring, to automatically adjust ventilation for a space according to real-time occupancy.
   c. Air curtains at warehouse overhead doors to reduce outdoor air infiltration at warehouse and garage spaces when the overhead doors are open.

3. Work Centre Asset Management

As discussed in the AM Strategy, Toronto Hydro applies a tailored investment approach to its head office located at 14 Carlton, in accordance with the age and deteriorated condition of the building.[11] The utility must reactively repair and maintain assets to reduce the risk of infrastructure failure, while navigating rising costs and operational challenges due to the building's age, limitations from the original design, heritage status, location, and operational significance (such as the housing of one of the utility's two enterprise data centres). One example that highlights the challenge of maintaining

[11] Exhibit 2B, Section D6, subsection D6.3.

the 14 Carlton work centre is ongoing façade repairs. The last major building masonry repair project was executed in 2016. Toronto Hydro plans to undertake the next repair project in the 2025-2029 rate period, as the risk of leaving the façade in disrepair could result in material falling from the building, causing hazards to employee or public safety. Since masonry repairs tend to be disruptive of building operations, involving significant vibrations, dust, loud noise, and scaffolding structures, the utility will plan these repairs in a manner that will minimize the risk to the 14 Carlton enterprise data centre, to avoid materially reducing data centre redundancy through planned outages and impacts during construction.

4. Work Centre Modernization

Toronto Hydro will selectively invest in its office workspaces to support an engaging environment that promotes productive and collaborative hybrid work, and to efficiently optimize office footprints. Investments in physical office spaces such as workstations, meeting rooms, leader offices, and shared spaces will enable employees to more efficiently engage in collaborative and inter-departmental group work. As Toronto Hydro's workforce grows and evolves, the utility will also leverage these investments to improve the efficiency of office spaces by consolidating workstations with a large footprint and providing space for new employees without requiring expansions.[12] Since the relevant assets typically consist of furniture and technology with relatively short lifecycles that are typically capitalized within ten years, the utility can plan investments in a flexible manner.

Investments to modernize work centres will support the growth of the utility's workforce and promote employee satisfaction, retention, and adaptation to flexible work practices, enabling personnel to efficiently and effectively perform business operations and serve customers.

c. Workstations

Toronto Hydro will install new workstations to replace bulky, space-inefficient, and aging or deteriorating workstations and increase employee density. These investments will reduce the cost of expanding the utility's workforce by providing a smaller physical footprint per employee.

d. Meeting and Training Rooms

Toronto Hydro will install audio and visual upgrades, including speakers, microphones, monitors, and TVs, in meeting and training rooms to support online web conferencing. The utility will also invest in

[12] See Exhibit 4, Tab 4, Schedule 4 for more information on Toronto Hydro's workforce over the 2025-2029 rate period.

modern furniture and design features to replace damaged and outdated furniture. These investments will support employee productivity and efficiency within the hybrid work environment.

e. <u>Common Spaces</u>

Toronto Hydro will make investments to update common spaces in its work centres to support hybrid office work by facilitating face-to-face communications. The purpose of these investments is to transform simplistic waiting areas and empty spaces in the utility's work centres into places for employees to work, gather around, charge devices, break up their day with a change of scenery, meet visitors or guests, share content, or take a phone call. Providing access to spaces for collaborative and in-person interactions to take place will contribute to employee satisfaction, and thereby productivity and retention.

E8.2.3.4 Security Improvements

Toronto Hydro will make investments to improve the utility's physical security infrastructure and support operations. Approximately 15 percent of the planned work under the Program is associated with security improvements. As the utility's properties are located in a broad range of neighbourhoods across the city of Toronto, stations and work centres are at risk of general theft, vandalism, and trespassing. Other threats include attempts by customers or members of the public to harass staff or threats to distribution operations and the distribution system by malicious organized actors, such as terrorism or cyber security breaches. Security measures that protect properties from physical threats also contribute to the safety of employees and critical equipment and assets, and to the overall reliability of the distribution system. The integrity of the utility's physical security systems is essential to ensure the distribution system's safe and reliable operation. Toronto Hydro will plan and make investments in a manner that is strategic, proactive, and responsive to identified risks as well as in alignment with the Ontario Energy Board's Cyber Security Framework.[13]

Electricity distributors are targets for security breaches because they play a critical role in providing an essential service and host a broad database of customer information, Similar to other public service providers and infrastructure operators such as hospitals, public transit operators, traffic management systems, emergency services, and financial hubs. The utility's planned security

[13] Ontario Energy Board, Ontario Cyber Security Framework (December 6, 2017) https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf

improvements will address existing gaps in the physical safety systems and implement proactive measures to lower the risk of safety breaches.

Toronto Hydro will focus on improving security measures in two categories: physical access measures and technology and network measures. Within the physical access category, the utility will implement physical changes to site security to improve control over access to properties. Within the technology and network measures category, the utility will improve video monitoring to provide improved response abilities by its Physical Security Operating Centre ("PSOC") to address breaches of security.

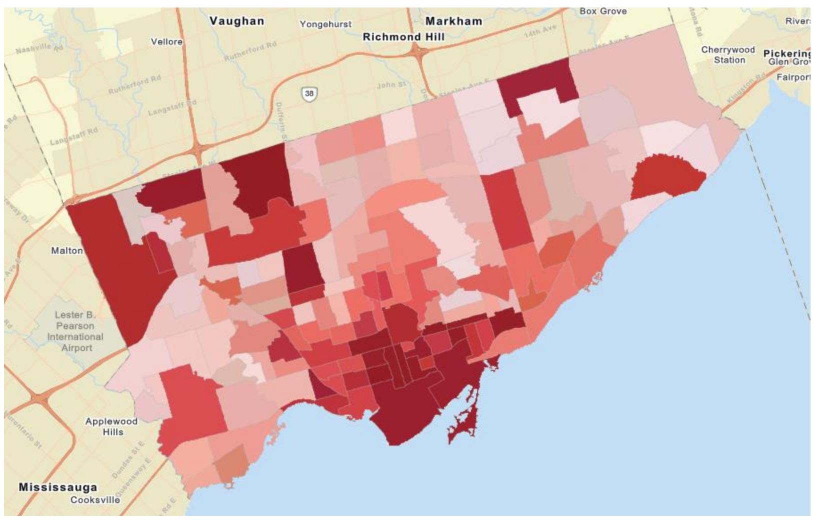


Figure 17: Major crime indicators; Toronto Police Service 2014-2021 statistics for breaking and entering and robbery.[14]

5. Network Security Improvements

The information technology and operating technology ("IT/OT") assets that enable Toronto Hydro to effectively and efficiently manage its distribution system, such as Supervisor Control and Data Acquisition ("SCADA"), also attracts heightened physical and cyber security risks. The utility must protect its IT/OT infrastructure and increase resilience against these diverse risks to ensure that critical grid distribution equipment and customer service functions remain reliably operational.

[14] Toronto Police Service Public Safety Data Portal https://data.torontopolice.on.ca/pages/major-crime-indicators

Within network security improvements, [redacted]

[redacted]

[redacted]

6. Physical Security Improvements

Toronto Hydro will invest in physical security measures to prevent unauthorized access to stations while also keeping them accessible for authorized personnel. Examples include providing increased outdoor lighting, repairing fencing, having adequate fence heights, and installing additional barriers such as barbed wire where required. Other improvements relate to door and gate openings. The utility will make investments to ensure that card readers work reliably when staff need to access a location [redacted]

Figure 18: Examples of University Station entrance door in poor condition (left) and after being retrofitted via the station door program (right).

E8.2.4. Expenditure Plan

Toronto Hydro plans to spend approximately $145.5 million over the 2025-2029 rate period to respond to the previously discussed needs and to make the proposed investments. The historical and forecast costs for the Program are set out in Table 6 below. The utility will determine the full scope of work to be performed under the work centres and stations categories based on risk-based prioritization in line with the AM Strategy and workload balancing over the 2025-2029 rate period.

Approximately 50 percent of Program expenditures will be dedicated to stations work. As discussed in detail above, 87 percent of Toronto Hydro's stations are over 40 years old and require significant upgrades to architectural, fire and life safety, mechanical and electrical, and civil and plumbing infrastructure and to ensure building and fire codes compliance. These investments will also enable the utility's security measures to better align with the principles of the Ontario Energy Board Cyber Security Framework.

35 percent of Program expenditures will account for work centre-related projects to address aging and deteriorating assets and office space modernization initiatives that will increase the productivity

of Toronto Hydro's workforce. This work will also facilitate investments in decarbonization at the utility's work centres to reduce facilities-related GHG emissions in accordance with the Net Zero 2040 Strategy.[15]

The remaining 15 percent of the Program expenditures will focus on implementing security improvements at stations and work centres.

In accordance with the AM Strategy, the Program will prioritize the proactive replacement of critical assets that are end of life and in poor condition for the 2025-2029 rate period. This approach will reduce the risk of emergency work, which can impact the safe and reliable distribution of electricity, and optimize the value the utility receives from assets in service.

Table 6: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Stations	1.7	4	11.8	11.3	10.3	15.1	15.1	14.5	14.5	13.3
Work Centres	5.5	6.2	6.9	8.0	5.5	10.2	10.4	10.5	10.6	10.6
Security Improvements	3.4	5.4	2.7	1.5	1.0	4.3	4.3	4.1	4.2	3.8
Total	**10.6**	**15.6**	**21.4**	**20.8**	**16.8**	**29.6**	**29.8**	**29.1**	**29.3**	**27.7**

Toronto Hydro will prioritize planned work according to the impact of a given asset's failure on the utility. As described in the AM Strategy, the Program first prioritizes assets whose failure poses a safety risk to Toronto Hydro personnel or the general public. The program next prioritizes assets whose failure impacts business continuity and the protection of the distribution system. Finally, the program prioritizes assets whose failure would impact productivity gains and the achievement of other business objectives third.

E8.2.4.1 Stations

Toronto Hydro assesses stations building assets and assigns a condition rating of critical, poor, fair, good or excellent on a regular basis in line with the AM Strategy. Assets that received a poor condition rating will be addressed within the 2025-2029 plan period. Assets in fair condition will be closely monitored and maintained under a preventative maintenance program. Assets will be also

[15] *Supra* note 8

be evaluated to ensure that a net reduction in GHG emissions to support net zero targets will be prioritized upon repair or replacement.

Finally, repairs for assets in good condition are not planned for the 2025-2029 period. Toronto Hydro will only replace assets that are end of life and are in poor condition. Work on these identified assets will proceed in line with the prioritization identified in the AM Strategy and described above.

Refer to Table 7 below for the planned capital expenditure work for Stations.

Table 7: Stations Capital Projects Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20%
Architectural & Interiors	Roofs, doors, window	15%
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	25%
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	30%
Civil & Sitework	Pavement, driveways, parking areas, walkaways	10%

E8.2.4.2 Work Centres

As mentioned in section E8.2.4.1 Stations, the AM Strategy and priority ratings are also used to classify work centre assets. Toronto Hydro will only replace assets that are end of life and in poor condition. This means deferring the replacement of assets that are end of life but are in fair or good condition or are “run-to-fail”.

Refer to Table able 8 below for the planned capital expenditure work for Work Centres.

Table 8: Work Centre Capital Project Planned Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20%
Architectural & Interiors	Roofs, doors, window	20%
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	20%
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	20%
Civil & Sitework	Pavement, driveways, parking areas, walkaways	15%
Office Workspace Transformation/ Modernization	Collaborative furniture, open spaces, hybrid work areas, audio visual enhancements	5%

E8.2.4.3 Security Improvements

The planned projects for the 2025-2029 rate period under the Security Improvements segment will support and expand integrated security features (e.g. video systems, keys, intercoms, access control measures, and duress stations). These security investments will both replace existing aging and deteriorated and also expand new assets to address any identified security gaps or risks [redacted]

Security improvements can be broken down into two areas: network security improvements and physical security improvements. Table 9 below shows a breakdown of the capital expenditures in each of these areas.

Table 9: Security Capital Projects Work

Project Category	Major Investments and Assets to be Replaced	Percentage of Estimated Segment Costs
Network Security Improvements	[redacted]	50%
Physical Security Improvements	Exterior lighting, fencing, card readers, automatic gates, exterior doors, exterior windows, and modernization.	50%

E8.2.5. Options Analysis / Business Case Evaluation ("BCE")

E8.2.5.1 Option 1: Run-to-Fail Approach

Under the run-to-fail approach, Toronto Hydro would delay necessary investments in work centres and stations and would perform replacements and repairs only on a reactive basis, when an asset fails. Since the majority of assets that are end of life and in poor condition are critical to the utility's operation, this approach would pose a significant risk to the business continuity of Toronto Hydro's operations. This approach would also run counter to the Ontario Energy Board's Cyber Security Framework, which stresses the importance of physical security to support utilities' cyber security objectives. This option would incur costs to reactively repair and replace assets, and significantly increase costs associated with reactive work, rentals, and labour to accommodate long lead times for specialty equipment.

Some of the effects of instituting a run-to-fail strategy would include:

- **Stations:** Maintenance and repairs to fire alarm panels, large HVAC units, and heritage station assets must be planned in advance to account for engineered design, analysis, material purchases with long lead times and/or custom-built materials (e.g. in support of heritage preservation). Applying a run-to-fail strategy to these types of assets would lead to business disruptions when the assets fail. Asset failure could also directly affect grid reliability if failing assets were to damage distribution equipment or expose them to damage and faster deterioration. The cost associated with unexpected failures and reactive repairs often outweighs the cost of proactive repairs due to the fact that reactive repairs generally require additional scope and rapid response involving labour overtime. This approach would also increase the risk of safety hazards by deferring work to bring the utility's stations into compliance with the Ontario Building Code by addressing existing water infiltration, building integrity and exterior lighting issues.

- **Security:** Deferring investments in security improvements will [redacted]
- **Work Centres**: Deferring efforts to decarbonize facilities assets at the utility's work centres would cause the utility's emissions to remain at current levels, compromising the utility's Net Zero by 2040 objective and leaving more decarbonization work for future rate periods.

E8.2.5.2 Option 2 (Selected Option): Maintenance and Replacement of End of Life and Poor Condition Assets and Investment in Security Improvements at Certain Toronto Hydro Facilities

Under this approach, Toronto Hydro would focus on asset lifecycles and condition assessments to selectively determine assets that require maintenance and replacement. Ongoing preventive maintenance reduces the risk of unexpected asset failures that could disrupt the utility's operations. Furthermore, this option allows the utility to optimize its capital expenditures by replacing assets in poor condition and retaining assets that are at end of life but in good condition.

Some of the effects of implementing this option would include:

- **Stations:** Assets that are end of life, but are either in good or fair condition or are run-to-fail by nature will remain in service, allowing the utility to focus expenditures and efforts on stations assets that require more immediate attention. By addressing hazards and asset deficiencies (e.g. those relating to lighting, HVAC, flooring, and stairs), Toronto Hydro can achieve and maintain compliance with legislative and regulatory requirements and minimize the safety hazards posed by current issues. This approach also allows the utility to use a competitive bids process to obtain more favourable acquisition costs for goods and services while maintaining the quality of work and process integrity.
- **Security:** By taking a proactive approach to improving security systems, Toronto Hydro can minimize physical threats to its assets by enabling a real-time response to threats. [redacted]

[redacted]

- **Work Centres:** Decarbonization, electrification, and energy efficiency investments under this option would enable Toronto Hydro to meet its emissions reduction outcomes over the 2025-2029 rate period and enable healthy progress to the utility's target to reach Net Zero by 2040, while pacing investments to contain costs for optimum benefits and avoid stranded assets.[16]

E8.2.5.3 Option 3: Preventative Maintenance and Replacements of All End of Life Assets and Investing in Security Improvements at All Toronto Hydro Facilities

Under this option, Toronto Hydro would replace all assets that are end of life, irrespective of specific asset condition, and would implement security improvements (such as upgrading video management system hardware and software) at a greater number of stations. This approach would also include preventative maintenance on all assets, without regard for asset condition, function, or criticality. This approach would require significantly higher capital expenditures, and would increase the risk of stranding assets.

In addition to the points listed under Option 2, the benefits of this option would include:

- **Stations**: Toronto Hydro would replace all assets at end of life, which would improve their reliability and provide operational savings by reducing the financial burden of reactive maintenance. These benefits would be offset by a significant increase in proactive capital investments under this option.
- **Security:** Security enhancements would be completed [redacted]
- **Work Centres:** This option would enable advanced lighting systems across all sites, HVAC retrofits, and renovations for refined BAS and building operation and offer greater employee work optimization. Under this option, Toronto Hydro would also significantly accelerate

[16] Exhibit 1B, Tab 2, Schedule 1

decarbonization, electrification, and energy efficiency investments, which would reduce GHG emissions faster and set the stage for the utility to reach Net Zero earlier than 2040.

E8.2.5.4 Evaluation of Options

Toronto Hydro has selected Option 2 as the Program's preferred approach for the 2025-2029 rate period since it ensures the optimal outcomes in terms of employee and public safety, grid reliability, cyber security, and GHG emissions while optimizing overall asset lifecycle costs and prudently pacing capital investments. In addition, the proactive approach to asset management in accordance with the AM Strategy under Option 2 would yield several productivity and efficiency benefits. This option provides the best safety, reliability, security and GHG emissions outcomes for ratepayers while controlling costs more effectively than Option 3.

Option 1 offers lower planned maintenance costs but potentially higher reactive maintenance costs. The implementation of this option would compromise the utility's grid reliability and would create the risk of business disruption. It would further compromise public and employee safety, and would lead to a less efficient allocation of capital expenditures, as the utility incurs cost and time benefits from the proactive procurement and replacement of facilities assets.

Option 3 offers additional asset reliability and would decrease the utility's operational costs but does not optimize the utility's asset management process and would represent a significant cost escalation for ratepayers.

E8.2.6. Execution Risks & Mitigation

The Program is vulnerable to several risks that could affect the planning and timing of proposed investments, including:

- Delays in obtaining the necessary approvals and permits may delay the start or completion of projects. To mitigate against this risk, Toronto Hydro will utilize subject matter experts to work with the necessary stakeholders in order to obtain approvals and permits in a timely manner. In addition, the utility will initiate the relevant processes as early as possible to ensure permits are issued for the project's scheduled execution timing and mitigate delays.
- The rising costs of material and labour are an ongoing issue in the post-COVID market. Supply chain disruptions have become an ongoing issue across many industries as well, and have continued to pose a risk throughout 2023.

- Legacy environmental conditions (e.g. asbestos or PCBs) might require further testing and analysis, which may affect project budget and execution schedule. To mitigate against this risk, Toronto Hydro will seek subject matter expertise for a thorough review of actual field conditions in high-risk locations prior to developing a project plan and incorporate these findings during the procurement process to limit the cost escalation of abatement work.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 36.7	**2025-2029 Cost ($M): 43.7**
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Efficiency - Reliability, Environment, Operational Efficiency - Safety, Financial Performance	

The Fleet and Equipment Services program (the "Program") governs the procurement, maintenance, and disposal of vehicles and equipment that are required to support Toronto Hydro's functional and operational needs. The Program's primary objectives are to optimize the utility's vehicle and equipment asset lifecycle costs, and to ensure that fleet assets perform reliably and maintain employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used primarily to perform distribution work and transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage, and monitor distribution work; and (2) equipment for employees and vehicles (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2020-2024 Rate Application.[1]

Toronto Hydro's capital investments in its vehicle fleet yield the following benefits:

- Optimization of vehicle operating costs;
- Minimization of fleet downtime due to repairs and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idling reduction;
- Improvements in shop efficiency through replacing older and poor condition vehicles that are more labour-intensive for maintenance purposes with new vehicles;
- Reduction in environmental impacts such as reductions in greenhouse gases emissions the amount of maintenance fluids used; and

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Schedule 8.3.

- Increased employee, field crew, and public safety, as newer vehicles are equipped with new safety technology (such as back-up cameras, lane departure warning, emergency braking warning, driver safety alerts, etc.).

E8.3.1.1 Toronto Hydro's Fleet Asset Management Strategy

Toronto Hydro optimizes the level and pace of capital investments to minimize the utility's maintenance and repair costs while maintaining safety and reliability. Toronto Hydro applies its fleet asset management strategy (the "Strategy") to achieve these outcomes. The Strategy takes a two-step approach as follows.

At the first step, it uses a Life Cycle Analysis ("LCA") approach to identify groups of assets whose characteristics (e.g. vehicle type, age, mileage, anticipated corrosion) enable the utility to estimate potential increases in their operating costs. As vehicles age, ownership costs such as purchase costs decrease and operating costs such as fuel, maintenance costs, and downtime increase. The utility uses its LCA to anticipate vehicle needs and fleet turnover for short term (0-2 years) and long term (2-7 years) expenditure planning purposes.

In the second step, the Strategy then assesses the actual condition of assets under consideration using an asset condition assessment to decide whether to replace or dispose of a given vehicle. This is an 85-point vehicle condition inspection metric to annually evaluate all asset components and determine whether parts and systems are working effectively. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, and operating environment, some vehicles that are in poor condition may require replacement before the LCA criteria is met and some vehicles that meet LCA criteria may be in good condition and not warrant replacement. Replacement cycles are additionally impacted by organizational objectives, such as the decarbonization and electrification of fleet assets, whereby the utility may replace decommissioned internal combustion engine vehicles with electric or hybrid vehicles.

The Strategy enables Toronto Hydro to replace vehicles at the lowest total lifecycle cost, which occurs at the point in time immediately before operating costs exceed ownership costs. It also promotes utility performance through the maintenance of a reliable fleet for completing distribution work in a timely and safe manner, and enables the utility to prudently plan and pace its fleet investments. Finally, the Strategy enables Toronto Hydro to meet its organizational objectives, such as the decarbonization of the utility's fleet assets.

To assist with modelling its LCA, Toronto Hydro has successfully operated in line with recommendations from a third-party consultant on the optimal replacement of fleet vehicles. The utility will continue to apply its current methodology over the 2025-2029 rate period. Over the 2020-2024 period, Toronto Hydro's application of the LCA has benefited the utility by enabling it to forecast future fleet needs with a high degree of accuracy, and plan and pace its investments appropriately to maintain fleet safety and reliability.

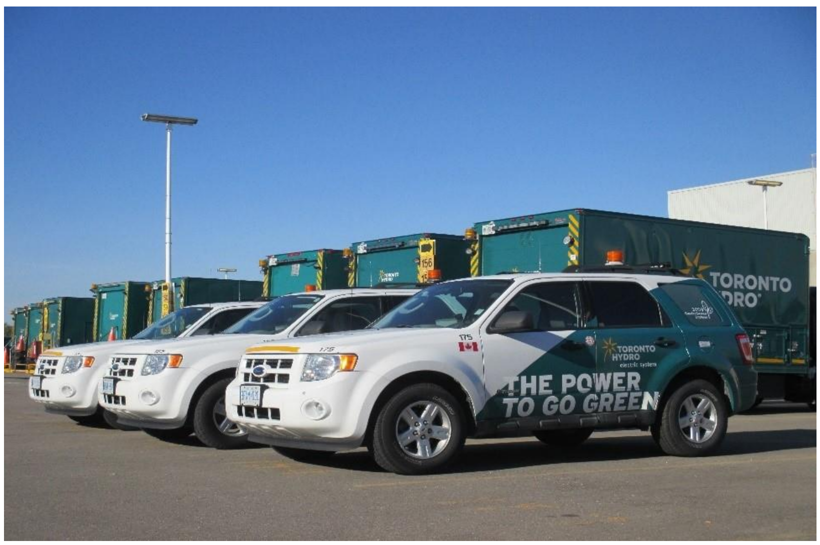


Figure 1: Toronto Hydro Fleet

E8.3.1.2 Decarbonizing Toronto Hydro's Fleet

Over the 2025-2029 plan period, Toronto Hydro will plan its vehicle and equipment investments in alignment with its objective to achieve net zero scope 1 greenhouse gas ("GHG") emissions by 2040, as outlined in the Net Zero 2040 Strategy document in Exhibit 2B, Section D7. Decarbonizing Toronto Hydro's fleet portfolio is critical to achieving this goal.

Aiming to reduce Toronto Hydro's GHG emissions, the utility will reconfigure its fleet composition to gradually increase its complement of electric and hybrid operation vehicles. Within a given vehicle class, electric vehicles ("EVs") and hybrid vehicles currently command higher capital costs than internal combustion engine ("ICE") vehicles, typically resulting in a 20-120 percent higher purchasing cost. In response to the OEB's direction in the last rebasing application to engage in a more detailed cost benefit analysis between EVs, hybrid, and combustion engine vehicles[2] and to assist in investing

[2] OEB Decision and Order, EB-2018-0165 (December 19, 2019), at p. 104.

prudently across these different vehicle types, Toronto Hydro analyzed various phasing and cost options for electrifying its fleet and the results of this analysis informs Toronto Hydro's procurement strategy for EVs and hybrid vehicles. In procuring electrified or hybrid vehicles, Toronto Hydro considers factors including safety, incremental annual capital cost and operating cost impacts, availability, similarity between electric and hybrid models to existing vehicles, ease of maintenance and operation, familiarity with the technology, scope 1 GHG reductions, and all associated change management considerations.

A paced approach for replacing ICE vehicles with EV and hybrid models results in a much more balanced capital expenditure profile than adopting more aggressive fleet decarbonization strategies. This paced approach helps Toronto Hydro meet its decarbonization goals, while minimizing the risk of stranded assets through the prudent management of OM&A costs (e.g. against possible increases from vehicles in poor condition and overdue for replacement), and capital expenditures (e.g. in respect of vehicles that are still in good condition despite being close to their projected end-of-life). Alternative approaches, such as aggressively replacing ICE vehicles in short order to accelerate decarbonization to a greater degree, would likely hamper the utility and its ratepayers from achieving optimum value from existing vehicles that are still in good condition, as such an approach would likely require such assets to be replaced sooner, meaning their total cost of ownership could not be optimized.

Conversely, an overly conservative approach attempting to extend the life of aging or poor-condition ICE vehicles and significantly defer capital investments in electric and hybrid vehicles would result in an increase in operational costs. A paced and balanced replacement strategy would help Toronto Hydro replace existing vehicles closer to their optimal lifetime total cost of ownership, while meeting its decarbonization goals. This approach would balance the utility's year-over-year capital expenditures and would not require significantly more capital investments compared to a like-for-like replacement strategy that that does not aim to meet decarbonization goals.

Toronto Hydro will prioritize EV options if they are able to meet the requirements necessary for users to carry out distribution work and other day-to-day operations. If EV options are not available in the market or the operational feasibility of deploying EVs for a particular function remains under analysis, the utility will consider hybrid options. If hybrid options are not available in the market, the utility will pursue ICE options. In view of the size and dense urban nature of its service territory, Toronto Hydro estimates that all vehicle types (ICE, EV, and hybrid) would perform at the same level of reliability.

The utility is currently exploring fully electric heavy-duty vehicles in small numbers and on a pilot basis as the market availability of these types of vehicles remains relatively low and further field experience is required to analyze the reliability and performance of these units under normal and emergency operating conditions. While the pilots continue, Toronto Hydro has adopted hybrid configurations of heavy-duty vehicles by having some vehicle components run off additional batteries. For example, some heavy-duty vehicles use electric power take-off ("PTO") aerial boom units and auxiliary batteries instead of gasoline- or diesel-burning generators for operating tools.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good operating condition and assets are replaced before critical equipment failures arise, which may necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing GHG emissions associated with fleet fuel consumption through: ○ Opting for hybrid and electric vehicles and biofuels while maintaining fleet reliability ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[3] ○ A targeted 8-10 percent reduction in tonnes CO_2 emission by the end of 2029.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by implementing vehicle packages and accessories that help ensure employees are working safely with minimal exposure to hazards.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the return on investment is justifiable.

	○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idling-reduction technologies; and replacing vehicles at the point of lowest lifecycle cost.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for the Program is Toronto Hydro's need for safe and reliable vehicles that support the utility's capital work and system maintenance during the 2025-2029 rate period and beyond. The utility requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, perform distribution work onsite, and provide shelter and working areas for workers on site. Vehicle uses on job sites include lifting and positioning material, storing material, preparing material for installation, acting as a planning station, and serving as shelter. Fleet vehicles must be available to support these work functions in a safe, reliable, and operationally efficient manner.

Toronto Hydro's fleet consists of several vehicle types that are designed to meet the utility's evolving portfolio of requirements and support other investment programs and the utility's distribution work. Heavy duty vehicles are required to transport equipment for distribution work. Light duty vehicles are required to facilitate the engineering and management functions of distribution work. Associated equipment assets for these vehicles are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors.

During the 2020-2024 rate period, the average age of assets in the utility's fleet has been trending slightly upwards. This is primarily due to the decommissioning and replacement of some vehicles after their optimal replacement age, delayed due to recent global supply chain issues affecting the availability of new vehicles for replacement and the need to retain a sufficient complement of vehicles enabling conformance with organizational health and safety requirements (e.g. worker social distancing) during the COVID-19 pandemic. The projected average age of the fleet for the 2020-

2024 rate period is 4.9 years. The projected average age of the fleet for the 2025-2029 rate period is 5.4 years.

E8.3.3.2 Safety

Toronto Hydro's investments mitigate the risk of deficiencies and safety hazards to the public and Toronto Hydro employees from structural, component, and electrical failures. Mitigating the following safety risks requires sufficient funding to keep the utility's fleet in good operating condition.

1. Corrosion

Managing corrosion and replacing corroded vehicles is important to maintain fleet reliability and safety. The utility's vehicles are continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. Humid weather and road salt can lead to corrosion that damages and weakens a unit's frame over time. As shown in Figure 2 and Figure 3 below, corrosion can also make vehicle body parts weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Corrosion of a vehicle's frame can lead to the frame breaking during a lift operation, cable pull, or material loading. Frame weakness can also decrease a vehicle's ability to withstand crashes and jeopardize the safety of the operators and the general public. Corroded vehicle components can also impact safety and are difficult and costly to repair. For example, a corroded transmission line that ruptures could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing control of the vehicle.

Figure 2: Corrosion on Cube Van Steps

Figure 3: Axle Corrosion on Bucket Truck

2. Hydraulics

Similar to the impact of corrosion, unaddressed hydraulic problems mediate in favour of vehicle replacement, as repairs are costly, take the vehicle out of service, and indicate that the vehicle's overall condition has deteriorated. Components such as the hydraulic hoses running through an aerial boom cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment and could also render aerial buckets on bucket trucks inoperable or cause a failure while an employee is operating the bucket. Rescuing a trapped employee from a failed aerial bucket presents a potential safety risk to the employee in the bucket, other field employees who are assisting with the operation, and the public.

3. Electrical

The maintenance of appropriate fleet age and condition is important to protect electrical circuitry from causing safety and reliability issues. The longer a vehicle is in service, the more likely electrical failure becomes. Electrical failures could lead to the malfunctioning of auxiliary safety lighting systems and onboard equipment required for field staff to perform their distribution functions.

E8.3.3.3 Reliability

Toronto Hydro's fleet investments ensure the reliability of the utility's distribution operations and the execution of its capital and maintenance programs. As vehicles age, they become increasingly unreliable and require more maintenance. In addition, even with regular maintenance, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability for aging vehicle models decreases over time, especially as certain makes and models of vehicles become obsolete. As a result, there is an increased probability that an older vehicle will remain out of service for longer periods of time while Toronto Hydro procures the requisite parts. Unreliable or unavailable vehicles adversely impact the utility's ability to provide acceptable levels of reliable service to customers and result in lost productivity and business disruption.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro tracks its fleet utilization by measuring "days used", meaning that the utility measures whether a given vehicle is used on a given business day, compared against the total number of work days in a year. This measurement produces both individual scores for the vehicle and aggregate scores for the fleet. The utility uses these scores to inform its investment planning and to optimize the use of its existing assets, by prudently maintaining a sufficient number of vehicles for use by business units as required, without retaining more vehicles than necessary. Optimal fleet utilization also allows for the regular maintenance of vehicles without interrupting distribution operations.

Toronto Hydro changed its fleet utilization methodology from "standard utilization percentage" to the current "days used" metric in the 2020-2024 rate period after monitoring both methods for efficiency and accuracy. The utility chose this updated measure of fleet utilization because it more accurately reflects vehicles' availability and reliability on a day-to-day basis compared to the previous utilization metric which omitted usage during overtime hours and did not account for usage during shift changes. It also allows the utility to track and measure the usage of particular vehicles against other vehicles of the same class within the fleet, to track on an ongoing basis if vehicles can be re-allocated to different departments and areas of distribution work to increase productivity. The below figure demonstrates Toronto Hydro's historical fleet utilization over 2018-2023 and estimated utilization over 2024-2029. The utility tracks utilization in two separate tiers of "Core Fleet" (distribution operations vehicles) and "All Fleet" (Core Fleet + pool vehicles, specialized support vehicles, etc.).

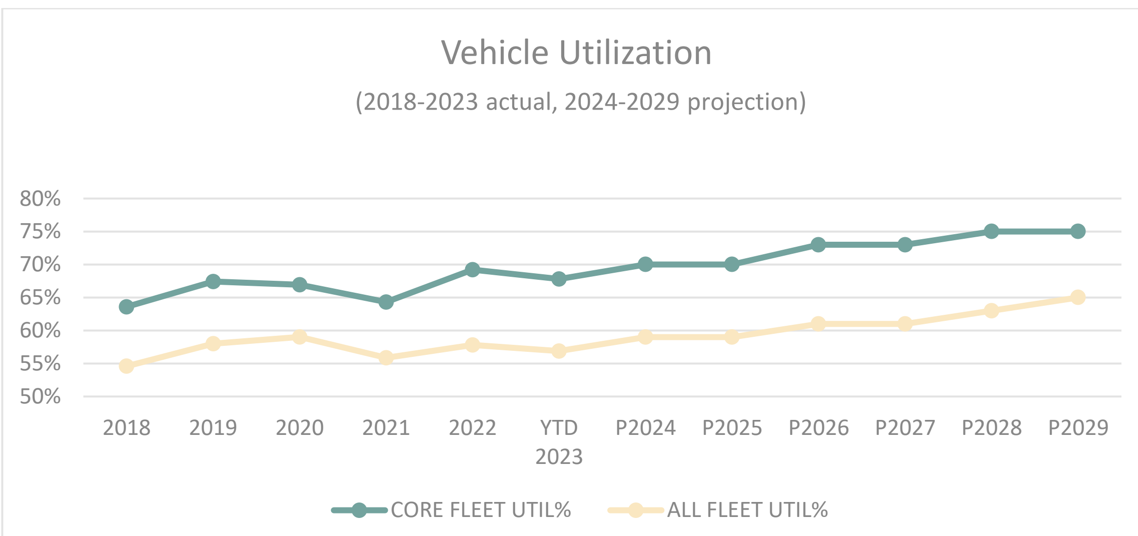


Figure 4: "Days Used" Vehicle Utilization Metric

Early in the 2020-2024 rate period, Toronto Hydro experienced countervailing factors exerting both upward and downward pressure on the vehicle utilization metric. The utility's ongoing decommissioning of underutilized vehicles within its fleet going into 2020 helped improve utilization rates. However, the onset of the COVID-19 pandemic and the health and safety measures that Toronto Hydro adopted (such as social distancing measures that limited each vehicle to a single occupant) required the utility to retain fleet vehicles that otherwise would have been taken out of service. This increased fleet utilization rates during the early stages of the pandemic, and decreased rates as social distancing measures were phased out prior to retiring the excess fleet vehicles. Toronto Hydro expects its utilization rate to continue to improve as effects of the pandemic subside and the utility rationalizes its vehicle count following the discontinuation of related measures.

The "All Fleet" utilization score includes highly specialized vehicles such as elevated bucket trucks for unique applications, emergency vehicles, Fleet and Facilities support vehicles, and pool vehicles that are crucial to the utility's operations because they provide support to specialized operations and are equipment that cannot be procured on a short-term rental basis. Toronto Hydro uses these vehicles during emergency situations such as power outages and mutual aid excursions, and to provide alternatives during extensive vehicle repairs or for other short-term requirements. These scenarios require a complement of pre-equipped vehicles to be readily available for emergency or rapid response.

The "Core Fleet" represents approximately 75 percent of Toronto Hydro's total fleet; the majority of these vehicles are assigned directly to Distribution Operations teams to help support day-to-day business operations. The core fleet includes a wide spectrum of light and heavy-duty vehicles.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Heavy Duty Vehicles	5.1	1.1	8.8	5.1	4.8	7.0	5.3	7.7	5.8	3.2
Light Duty Vehicles	1.3	1.1	5.5	1.2	1.1	2.0	4.4	0.9	1.9	4.4
Equipment	0.1	0.1	1.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Total	**6.5**	**2.3**	**15.5**	**6.4**	**6.0**	**9.2**	**9.9**	**8.8**	**7.9**	**7.8**

Toronto Hydro's capital expenditure and asset replacement planning for the Program begins several years in advance in order to account for lead times and to effectively procure vehicles. The utility uses the Strategy to identify candidate vehicles for future replacements, plan the pace of procurement, and identify the optimal point at which to replace a given asset based on ongoing assessment of its condition. If Toronto Hydro does not receive the requested funding and is unable to make the planned investments over the 2025-2029 rate period, its fleet will incur increasingly high operational costs, will be less reliable, and will pose a greater risk to safety, to ongoing distribution operations, and to the execution of capital programs.

As shown below in Table 5 below, Toronto Hydro shuffles asset replacements across the five-year rate period as necessary to balance spending year over year and prudently manage costs. Replacing assets in batches and optimizing spending in a given year makes it easier for the Program to balance work throughout the lifecycle of the vehicle. Table 6 shows the parameters and factors by vehicle class that inform Toronto Hydro's prioritization of its long-term capital planning for fleet and equipment assets.

Table 5: Replacement Costs[4] for Fleet by Segment for the 2025 to 2029 Period ($ Millions)

Description	2025		2026		2027		2028		2029		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Heavy Duty	13	7.0	13	5.3	23	7.7	11	5.8	12	3.2	**29.0**
Light Duty	18	2.0	26	4.4	10	0.9	12	1.9	40	4.4	**13.6**
Equipment	2	0.2	1	0.2	1	0.2	1	0.2	10	0.2	**1.1**
Total	**26**	**18.6**	**39**	**8.4**	**35**	**8.8**	**22**	**9.1**	**52**	**2.4**	**43.7**

Table 6: Factors Influencing Capital Planning by Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	24-36 months	$0.32	High
Light Duty Vehicles	Medium	10-18 months	$0.06	Medium
Equipment	Low	6-12 months	$0.07	Low

Heavy duty vehicles take the highest priority in planning because they are the costliest and take the longest to procure, with timelines typically around 24-36 months. The procurement process begins by determining the specifications of vehicles and continues to with the delivery of the units. In planning its heavy-duty fleet, Toronto Hydro engages multiple vendors to determine the feasibility of particular vehicle configurations and ensure all vehicle components can work as intended.

[4] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply, and any other aftermarket additions required in a particular light duty vehicle.

The procurement of light duty vehicles follows the same procurement steps, but the timelines are typically shorter. Light duty vehicles usually feature more standardized specifications as they are typically used for transporting people or equipment, and are not used to perform distribution work. Thus, it takes the utility less time to determine the specifications of the light duty vehicle and prepare it for operations once acquired, since such vehicles typically require fewer components to be built or installed.

E8.3.4.1 Equipment

Toronto Hydro's equipment investments over the 2025-2029 rate period are targeted to ensure safety for fleet operators and to implement decarbonization measures where options for switching to EVs or hybrid vehicles are limited. These investments include anti-idling technology, GPS units, laptop mounts installed in vehicles, trailers, and lift equipment, described in greater detail below. The utility replaces equipment on a reactive or "run to fail" basis because equipment generally has a long lifespan, procurement times are quick, replacements are available on the market, equipment failure poses a low safety risk, and variability in use makes it difficult to predict when a given piece of equipment will require replacement.

Table 7 below shows the forecasted costs of replacing equipment on a reactive basis. Toronto Hydro assesses equipment every six months through a preventative maintenance review and determines respective replacements based on units' condition and performance.

Table 7: Equipment Replacement Costs For 2025 to 2029 Period ($ Millions)

	2025	2026	2027	2028	2029	Total
Equipment	0.22	0.22	0.22	0.22	0.2	1.1
Total	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**1.1**

The utility's investments in telematics and anti-idling systems help the utility monitor and continuously improve vehicle idling, utilization, driver safety, and diagnostic maintenance. Some heavy-duty diesel vehicles are equipped with GRIP anti-idling technology to reduce idling, which increases the vehicle's lifespan and decreases GHG emissions. The utility's purchase contracts require vehicle vendors to comply with these specifications. The anti-idling system manages, monitors, and provides real-time data on battery voltage, coolant, temperature, idling, anti-theft mode, and engine starts and stops. It also provides reporting on driver behaviour that helps reduce speeding and harsh braking, which increases fuel efficiency. The use of telematics GPS hardware and software provides several benefits, including real-time tracking of vehicle locations and maintenance indicators,[5] aiding customer complaints investigations and claims by enabling access to historical tracking of the entire fleet and history of vehicle location, providing speeding notifications based on local speed limit and set data, and the management and creation of zones based on work centre locations to optimize vehicles' arrivals and departures.

Other onboard equipment includes laptop mount kits for ruggedized laptops used in the field, equipped with pedestal, docking station, and wiring needed to power devices. These mounts are installed in most light and heavy-duty vehicles to facilitate the ergonomically safe use of laptops for onsite crew inspections, site visits, and other situations without requiring field crews to drive back to a work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic, and adjustable base) and periodic risk assessments help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in a cube van which includes a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.

Figure 5: Laptop Mount Installed in Cube Van

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the 2025-2029 rate period. The first, managed fleet deterioration, entails a fleet replacement strategy that would increase the average vehicle age by approximately 5-7 percent across the fleet. The second, sustained fleet replacement, entails replacing vehicle assets at the optimal age as outlined in the

[5] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, and PTO used for commercial vehicle operation registration ("CVOR") units.

Strategy, i.e. when the lifecycle costs of a given vehicle are the lowest. The utility is proposing to follow this option, as it enables the utility to maintain vehicle availability and reliability, make process towards decarbonization goals, meet customer expectations and facilitate the execution of the utility's investment plan. The third approach would entail improving the lifecycle of vehicles by one year in order to improve vehicle reliability and availability, and would pace the majority of the utility's investments to decarbonize its fleet into the upcoming rate period.

E8.3.5.1 Option 1: Managed Fleet Deterioration

This option delays heavy duty vehicle replacement to one year later than recommended by the LCA, subject to assets' actual condition assessments. However, Toronto Hydro would not delay the procurement of light duty units in order to continue making progress on vehicle electrification in accordance with the utility's Net Zero 2040 Strategy.

Overall, this option would translate to an approximately 5-7 percent increase in the average vehicle age across the fleet. Under this option, the Program's objective would be to ensure that the vehicle replacements continue at an acceptable pace without materially compromising the reliability and safety outcomes. The investment plan under this option, would contemplate replacing all light duty vehicles and ten heavy duty vehicles with electric or hybrid vehicles.

As this option is based on a reduced capital expenditure profile, it would likely restrict Toronto Hydro's flexibility to scale fleet investments up or down in accordance with the utility's needs. This approach also risks increasing labour costs and vehicle downtime due to aging vehicles requiring more frequent maintenance and more support compared to the other options. To the extent that these challenges cause fleet capacity issues, there may be also delays of or interruptions to capital work, system maintenance, and outage restoration, adversely affecting a number of safety, reliability, and customer service outcomes.

More specifically, this option would have the following consequences:

- Unit field failures will likely increase as vehicles age and adversely affect field crew productivity. In some cases, unit field failures may render Toronto Hydro unable to conduct system maintenance and capital work as planned. This will lead to higher operational labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).

- The severity of asset failures is likely to increase and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment, and environmental spills.
- Toronto Hydro's operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase.
- The utility may have to increase its vehicle count to maintain similar vehicle availability levels in order to deliver equivalent service levels to customers. This is because as vehicles age, time out of service will likely also increase due to increasing repair challenges that result from an aging fleet (such as deteriorating components and the consequent need for more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, the utility may have to rent new equipment for vehicles at a significant cost.
- The replacement of vehicles that have reached a total state of failure may require long lead times (e.g. up to 30 months for the purchase and delivery of specialized vehicles). During this period, Toronto Hydro's ability to perform capital work and system maintenance may be impaired or delayed if alternate vehicles cannot be sourced internally or through renting or leasing externally.

E8.3.5.2 Option 2: Sustained Fleet Replacement (Recommended Option)

This spend option replaces vehicle assets at the optimal replacement age. As discussed in the Strategy, Toronto Hydro determines a vehicle's optimal replacement age by using the LCA as a baseline indicator, with adjustments based on the assessment of individual assets' condition. Under this option, the Program's objective would be to ensure that vehicle replacements occur at the point in time where the lifecycle cost of ownership is lowest. The electrification strategy under this option would involve replacing all light duty units and 15 heavy duty units with electric or hybrid vehicles.

The proposed vehicle replacement pace under this option would allow the sustainment of the fleet at the optimal age profile and result in a lower average age of vehicles compared to the managed fleet deterioration option. This approach would optimally balance capital expenditures against the need to ensure the reliability and availability of fleet and equipment assets. In addition, this option would optimally support the utility's progress towards its decarbonization goals.

This option would have the following consequences:

- Toronto Hydro will replace vehicles according to asset management criteria that will optimize the average total cost of vehicle ownership over time;
- Overall vehicle reliability will improve, resulting in less downtime, fewer vehicle failures, and improved field crew productivity;
- Fleet vehicle and equipment performance will improve;
- Overall safety of fleet vehicles will improve thanks to enhanced safety features found in newer vehicles; and
- Fuel efficiency will improve, leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Improved Fleet Availability & GHG Emissions Reduction

This spend option aims to replace fleet vehicles sooner by reducing the baseline lifecycle assumptions by one year. This would result in an approximately seven percent decrease in the average age of Toronto Hydro's fleet compared to the sustainment option. The objective of the Program under this option would be to improve vehicle reliability and availability. By replacing vehicles earlier, the utility would avoid the more significant and costlier repairs typically seen in the final year of a vehicle's lifecycle and increase vehicle availability. For example, for certain vehicle types, the vehicle's lifecycle could be aligned with the battery warranty to avoid significant battery repair costs, which often exceeds the value of the vehicle itself when nearing end of life. The improved condition of fleet vehicles would also result in overall lower operational expenses due to less maintenance needs and the lower likelihood of having to rent vehicles to substitute for out-of-service fleet vehicles. The resulting higher reliability levels compared to other options would allow Program resources to better focus on continuous improvement since vehicle conditions will remain at more consistent levels across the fleet. This option also aims to accelerate the electrification of the fleet by replacing all light duty vehicles and 20 heavy duty vehicles with electric or hybrid vehicles in accordance with Toronto Hydro's Net Zero 2040 Strategy.

This option would have the following consequences:

- Pre-emptive mitigation of age-related safety risks and associated repair costs;
- Improved reliability levels reducing reliance on external repair services for more significant repairs;
- Better availability of vehicles to perform capital work, system maintenance, and outage restoration during extreme weather and other emergency events; and

- Potential logistical challenges with putting greater numbers of new vehicles in service and disposing of decommissioned vehicles.

E8.3.5.4 Evaluation of Options

Toronto Hydro proposes to proceed with Option 2, the Sustained Fleet Availability approach, as it is the most cost-effective option to manage Toronto Hydro's vehicle fleet while providing the opportunity to meet Toronto Hydro's Net Zero goals. These aims help ensure asset reliability, customer service, and contribute to employee and public safety.

Replacing the vehicle fleet on a Managed Deterioration basis (Option 1) will not only adversely affect field crew productivity and hamper planned system maintenance and capital work, but also result in upward pressure on vehicle maintenance and repair costs. In comparison to Option 2, the Sustained Fleet Replacement scenario, this option allows for further investment in electric and hybrid vehicles while also further improving fleet age profiles to enhance reliability and cost-effectiveness.

The Improved Fleet approach (option 3) accelerates capital investments; but also reduces asset maintenance and repair costs. Option 3 speeds up the electrification of the fleet but does not allow for the prudent and measured evaluation of EV technology to ensure its suitability in our operating environment. Both options 2 and 3 allow us to achieve 2040 Net Zero goals.

The summary of this options analysis is as follows:

Table 8: Options Analysis Summary

Outcome Measures at End of 2029	Deterioration	Sustainment	Improvement
Option Cost ($M)	34.35	43.69	47.45
Average Fleet Age (years)	6.7	5.4	5.0
GHG Emissions (tonnes CO2)	1222	1177	1034

E8.3.6 Execution Risks & Mitigation

There are three primary execution risks inherent in the Program: (i) escalating vehicle costs; (ii) increasing procurement lead times; (iii) supply and availability of fully electric heavy-duty vehicles. Vehicle costs have been escalating since the onset on the COVID-19 pandemic due to supply chain issues in getting parts and vehicles delivered; the weakening of the Canadian dollar versus the American dollar which impacts most heavy duty vehicle chassis' costs; semiconductor shortages impacting the availability of both light and heavy duty vehicles; automotive industry production and manufacturing cuts due to the pandemic and changes in the workforce; and the unpredictability and longer lead times for acquiring fully electric vehicles.

As a mitigation strategy, Toronto Hydro issues multi-year tenders with limitations on cost increases per year where possible and provides vendors the option to update pricing and delivery schedules for EV and hybrid options on tender submissions as they become available. In addition, where possible, the utility chooses Canadian suppliers to maximize repair efficiency where they are the lower cost bidder. The Program has also extended planning lead times for procurement to accurately reflect the most current delivery expectations provided by vendors given supply chain, production, and electrification constraints. For more information on the more general mitigation measures the utility has adopted with respect to procurement risks, please refer to the Supply Chain Services program in Exhibit 4, Tab 2, Schedule 15.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 256.6	**2025-2029 Cost ($M):** 301.3
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Reliability, Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, and Financial Performance	

The Information Technology and Operational Technology Systems (IT/OT) program (the Program) invests in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services.[1] Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's Information Technology Asset Management Strategy and Investment Planning procedures (Strategy) and are intended to mitigate risks to reliability, cybersecurity, and the utility's business operations.[2]

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres), security appliances and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;

[1] Note: Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise. See: Gartner Inc., IT Glossary, Operational Technology Definition.
[2] Exhibit 2B, Section D8.

- **IT Software**: includes software applications that provide process improvements and operational capabilities to a range of customer-facing and business functions; and,
- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition (SCADA) infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Implementing and maintaining a range of customer service and communication tools and systems; ○ Improving the customer experience of interacting with the utility through digital platforms; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities; and ○ Supporting the creation and maintenance of cyber security controls to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Providing the technological infrastructure framework required to improve the distribution system's ability and capacity to evolve and meet emerging needs (e.g. the integration of distributed energy resources, new load types such as electric vehicles, and increasing reliance on energy flow data); and ○ Providing the technological infrastructure required by the utility to continuously improve its processes and adapt to evolving legal and regulatory requirements, business conditions, and customer expectations.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency (TRIF) by: ○ Enabling the constant monitoring of substation and field assets to prevent asset overloads and failures, which might result in injuries to anyone in the close proximity of the equipment; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as SCADA, Automated Vehicle Locator, Radio, and Network Management System).
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate customer and market invoicing and settlements and financial reporting and recordkeeping.3

1 E8.4.3 Drivers and Need

2 **Table 3: Program Drivers**

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, Functional Obsolescence, Modernization, and Electrification

[3] Exhibit 2B, D8. Tier 1 applications enable Toronto Hydro's critical business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex, highly redundant underlying infrastructure such as databases, middleware, storage, and network.

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, comply with existing and emerging legal and regulatory requirements, and provide the technological infrastructure to continuously improve and adapt its business processes to evolving industry trends such as the pace of electrification increases and the resulting changes in customers' needs and preferences.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure the ongoing reliability of systems that support customer-facing services and core distribution operations by maintaining a low risk of failure. The utility's IT hardware also ensures a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

IT Hardware segment consist of two subsegments:

- IT Hardware Infrastructure;
- IT Cybersecurity Practice.

1. IT Hardware Infrastructure

Toronto Hydro employs many software applications to automate processes and efficiently execute a variety of daily tasks such as preparing customers' bills and dispatching crews to respond to outages. Renewing the underlying IT Hardware on a routine basis is essential to ensure that the software applications remain available. IT Hardware Infrastructure refers to the environment supporting Toronto Hydro's entire Information Technology ecosystem. It aims to provide adequate sizing, availability, scalability, performance and security of the environment to fit business application needs, while ensuring obsolescence prevention and vendor supportability. IT infrastructure assets are classified as either Endpoint Assets or Core Infrastructure Assets.

Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations. These include computing assets (e.g. desktops, laptops, and tablets) that support the execution of business processes, data transactions and analysis, as well as printing assets (e.g. printers, plotters, and photocopiers) that translate electronic documents like engineering drawings and contracts onto paper. Both are relied upon extensively by Toronto Hydro's users to execute daily work across the utility.

Core Infrastructure Assets are responsible for the computation, storage, and communication necessary to support IT systems. Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic. Storage assets enable the secure retention of digital data such as customer information, and include disk and flash arrays, which store records for access by servers. Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that users can access information from a central IT system. Network and telephony assets enable computers, services, and storage devices to exchange data and manage communication services. Figure 1 depicts the typical structure and dependency of IT infrastructure assets.

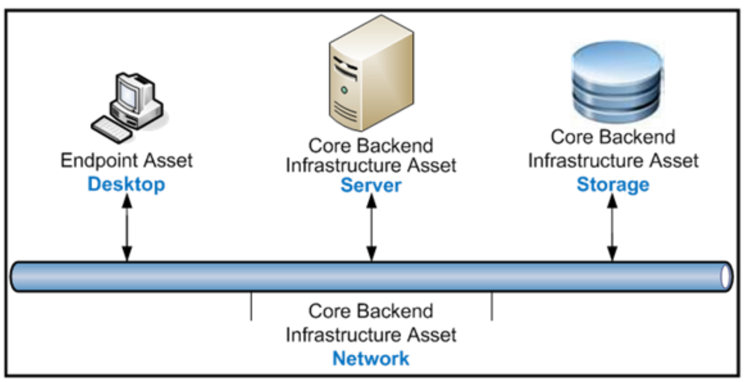


Figure 1: Typical Endpoint Asset to Core Infrastructure Relationships

IT infrastructure environment forms the foundational technology layer upon which all other IT functions and business processes are deployed, including IT Cyber Security, IT Operations, IT Software and company-wide resourcing and workforce management functions. Operational efficiency improvement opportunities are continuously explored and evaluated. These include provisioning more powerful hardware to allow for denser resource deployment and streamlining of systems architecture to fully realize technological potential.

The lifespans of IT infrastructure assets range from four to seven years, which are considered to be within industry norms. At the end of its lifecycle, hardware assets' risk of failure increases significantly, potentially impacting core business processes. To determine the refresh cycle for existing hardware, Toronto Hydro maintains an inventory of infrastructure assets that includes technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are up-to-date and available to support the effective and efficient execution of the utility's operations.

Adhering to this approach, approximately 90 percent of Toronto Hydro's core backend infrastructure, and 100 percent of its endpoint assets will need to be replaced during the 2025-2029 rate period. This includes data and voice network routers, switches and appliances, storage network switches, storage arrays, data backup appliances, file storage appliances, UNIX, Linux and Windows servers, monitoring appliances, uninterruptable power supplies and others. IT hardware infrastructure assets support a number of customer service functions. In 2023, approximately 320,000 customers use the online electronic billing function and have accounts that provide key self-serve functions, such as management of account details, customer moves, payment options, and landlord information as of 2022. IT hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience significant delays in completing routine transactions. This would impact overall customer satisfaction and may result in increased volume of calls and complaints to Toronto Hydro's Call Centre. Higher call volumes will also limit Toronto Hydro's ability to meet Ontario Energy Board (OEB) prescribed service quality metrics such as First Contact Resolution.

IT hardware supports systems are also used to manage field crews and respond to outages, and thus are critical to the utility's ability to conduct day-to-day operations and ensure reliability. By providing access to real-time data for crew availability, geographical location of outages and crews, these systems enable Toronto Hydro to deploy crews in a timely and effective manner and restore power to customers faster. In the event of core infrastructure failure, the functionality of these applications would be impaired, leading to longer outage response times and poor customer satisfaction. Longer outage response times will negatively impact Toronto Hydro's ability to meet OEB prescribed reliability performance standards such as System Average Interruption Duration Index (SAIDI).

IT hardware also underpins the utility's environmental, health, and safety processes across its work centres and job sites. Such processes range from completion of site conditions and safety forms, review of Material Safety Data Sheets, safety and environmental audits, and incident and claims investigations. In the event of IT hardware failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues. This may be compromising workers' safety or contributing to non-compliance with applicable OEB requirements and Utility Work Protection Code.

IT hardware investments are planned and implemented based on existing and future utility needs and operational requirements. This allows Toronto Hydro to execute its plans and programs securely and efficiently in pursuit of its short-term and long-term objectives. IT hardware standards are regularly reviewed, assessed, and implemented based on the utility's existing and ongoing requirements from operational, regulatory and customer service perspectives. In order to continuously adapt its standards and processes to meet these needs, Toronto Hydro requires ongoing investments in its IT hardware assets.

2. IT Cybersecurity Practice

Cybersecurity practice is responsible for the ongoing protection of the organization from all external and internal information security threats. Growing industry reliance on IT as a key business enabler also carries the increased risk of cybersecurity exposure. Global cybersecurity threat landscape is constantly evolving, with attacks ranging from social engineering to destructive ransomware attacks to nation-state backed advanced persistent threats. Cybersecurity has been identified as one of the growing corporate risks. As such Toronto Hydro is continuously investing in cybersecurity controls to monitor cybersecurity threats and develop a robust response to cybersecurity breaches which serves to minimize the potential damage to enterprise assets, data and brand reputation. The primary role of the cybersecurity practice is maintaining a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets. Cybersecurity practice includes a combination of Run, Grow and Transform (RGT) investments, as per Gartner's RGT model.

The Run program is primarily centered around the maintenance and organic growth of existing Cyber Security capabilities. From the Threat, Risk and Compliance (TRC) perspective, this includes the orchestration of recurring enterprise IT asset security patching as well as lifecycle upgrades of perimeter and endpoint security controls, such as firewalls, Intrusion Prevention Systems (IPS) and malware protection software. Identity & Access Management (IAM) aspect of the Run program is aimed at ensuring that the organization maintains secure, role-based access to resources, properly logged for auditing and forensic analysis purposes.

The Grow program expands baseline cybersecurity capabilities, through the adoption of advanced threat protection technologies and user education processes aimed at curbing the exposure to social engineering attacks. Grow initiatives are focused on the expansion and strengthening of existing protection capabilities, through the investment into advanced technologies, such as behavioral Endpoint Detection and Response (EDR) solutions to prevent zero-day attacks, perimeter and endpoint Data Loss Prevention (DLP) solutions to stop information exfiltration, and intelligent email phishing prevention solutions.

The Transform program explores pioneering technologies and cyber-defense mechanisms to attain higher protection levels for digital assets, safeguard customer and employee privacy and install stakeholder confidence. Falling under this program are initiatives such as proactive threat hunting, persistent attack surface management,[4] honeypots,[5] network detection & response, attack pattern recognition and micro-segmentation.[6] These initiatives are aimed at limiting corporate exposure to and damage from advanced threats, such as zero-day ransomware attacks.[7]

Investments in cybersecurity solutions are required to ensure that current systems, applications and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to evolving threat landscape, and regulatory compliance obligations.[8] This ensures that the existing security controls are continuously enhanced and matured to meet the cyber resiliency requirements. Cybersecurity requirements need to detect uncertainties in the environment such as pandemic driven infrastructure changes, heightened monitoring requirements, Advanced Persistent Threats (APT) related to the geopolitical situation, and exposure to critical zero-day security vulnerabilities. In order to build security requirements that can respond to these uncertainties, Toronto Hydro plans to make continuous investments into its robust cyber security infrastructure using layered Defence-in-Depth model to ensure the protection of both IT and OT assets. These investments will help the utility to develop a strong cybersecurity posture which will be essential in

[4] The continuous discovery, analysis, remediation and monitoring of cybersecurity vulnerabilities and potential attacks to the system.
[5] A decoy system that is designed to look like attractive targets, and deployed to allow IT teams to monitor the system's security responses and to redirect the attacker away from their intended target.
[6] A method of security that involves dividing a network into segments and applying security controls to each segment based on the segment's requirements.
[7] A type of ransomware which exploits unknown and unprotected vulnerabilities.
[8] *Electricity Act*, 1998, SO 1998, Ch 15, Sched A,
Ontario Regulation 633/21, Section 3. Section 3 of the Regulation allows customers to submit authorizations to allow third party access to their energy data.

providing an effective response to expected increases and sophistication in emerging cybersecurity threats, due to industry shift towards electrification.

Outdated or reactive security controls and technologies pose several risks to Toronto Hydro's systems, applications, and endpoints including risks to business continuity, distribution system reliability, and financial health. Toronto Hydro is governed by a variety of legislative and regulatory requirements relating to privacy and data security, including the OEB's Cyber Security Framework. The planned expenditure for IT Hardware ensures that Toronto Hydro is able to protect its IT environment, meet security compliance requirements, provide assurance to our industry partners, customers and stakeholders, and evolve its security controls and technologies and associated processes to adapt to the emerging security threats, in response to industry shift towards electrification.

E8.4.3.2 IT Software

Investment in IT software is required in order to ensure that current applications continue to operate reliably, with minimal risk exposure to cyber threats, while also making targeted and prudent IT investments to enhance functionality. Functional improvements are also required in response to core business needs or risks in addition to meeting evolving regulatory or compliance obligations. IT software is an integral part of a modern utility. Toronto Hydro relies upon, and must maintain, various IT software systems to efficiently manage core operations and business processes and to execute planned programs relating to distribution grid operations, engineering design, construction, customer billing and corporate services (e.g. finance, human resource management, legal and regulatory).

Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering capital programs and satisfying changes in customers' needs and expectations and other stakeholders that the organization interacts with. Ensuring reliability and availability of software plays a crucial role in supporting modernization of its business processes in response to the industry shift towards electrification, including electric vehicles (EVs), and distributed energy resources (DERs). If software is not reliable or available, it can hinder the utility's ability to enable these technologies. Moreover, if the software used to manage the grid is unreliable, it can lead to an increase in the number of outages and other disruptions, resulting in lower customer satisfaction. For example, automating customer-facing processes through enhanced channel offerings and the use of targeted digital tools can improve the overall customer experience. However, if the software used for process automation is unreliable, it can cause errors and disruptions in accessing these services, resulting in poor customer satisfaction.

Software applications deliver tangible value to customers directly through customer-facing IT services, and indirectly through the improved performance or avoided risks of business-facing platforms and solutions. To maintain a reliable and productive suite of IT Software, Toronto Hydro makes three types of investments: Software Upgrades, Software Enhancements, and Regulatory Compliance.

1. Software Upgrades

Toronto Hydro plans to upgrade all of its software applications over the 2025 to 2029 period. These upgrades will ensure that Toronto Hydro's software systems receive support from vendors, keep pace with technology changes in the industry, remain integrated with other relevant software systems, and are protected against future cyber security threats.

When IT systems have surpassed the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged downtime, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver services to its customers.

In addition, IT systems without vendor support do not receive security patches and upgrades or fixes, rendering the applications more vulnerable to cyber-attacks. These attacks attempt to tamper with normal IT system operations, gain unauthorized access to customers' and employees' confidential information, or cause a machine or network resource to malfunction or be unavailable to authorized users.

For example, the ransomware cyber attack in May 2021 on Colonial pipeline (a major fuel pipeline operator in the United States that carries gasoline, diesel, and jet fuel from refineries), resulted in the shutdown of the pipeline for several days, causing a shortage of fuel in several states and leading to panic buying and price spikes at gas stations. Colonial pipeline paid $4.4 million in ransom to the hackers to regain control of its systems[9].

In October 2021, the Toronto Transit Commission (TTC) cyberattack resulted in the disruption of multiple computer systems, including email and payroll, causing significant inconvenience for both customers and employees. The attack impacted the ability of the transit agency to communicate with its customers, as the company's website and social media channels were temporarily taken offline.[10]

In December 2022, the cyberattack on The Hospital for Sick Children had a significant impact on its operations. The attack resulted in the disruption of several services, including appointment scheduling and telemedicine. The hospital was forced to reschedule some appointments and revert to manual processes to continue providing essential medical care. The attack also affected the hospital's ability to access patient data and medical records, which posed a significant risk to patient safety and care.[11]

These events highlight the real risk and consequences of cyber intrusions and the ongoing need for Toronto Hydro to regularly upgrade its software in order to protect its systems from external attacks. A leak of Toronto Hydro's sensitive operational information could lead to and assist in malicious attempts to jeopardize day-to-day operations and, in extreme cases, the successful exploitation of a system vulnerability could cause mass outages across the grid.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lack vendor support lifecycles. This exposes the IT systems to security and reliability risks that could result in severe outcomes. Functional obsolescence is an additional consideration driving the need to invest in software upgrades. Finding skilled resources to ensure ongoing support optimization for legacy systems is and will become more challenging.

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[9] Colonial Pipeline, Media Statement Update: Colonia Pipeline System Disruption, "online", https://www.colpipe.com/news/press-releases/media-statement-colonial-pipeline-system-disruption
[10] Toronto Transit Commission, TTC provides update on cyber security incident, "online", https://www.ttc.ca/news/2021/November/TTC-provides-update-on-cyber-security-incident
[11] Sick Kids, SickKids Lifts Code Grey with 80 per cent of priority systems restored, "online", https://www.sickkids.ca/en/news/archive/2023/sickkids-lifts-code-grey-with-80-per-cent-of-priority-systems-restored

Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying infrastructure. Toronto Hydro categorises its Software applications as Tier 1, Tier 2, and Cloud solutions.[12]

Tier 1 applications support a variety of critical processes across the utility. These applications are functionally integrated with other applications, and are supported by a host of databases, middleware, storage and network devices. Tier 1 systems include: Geospatial Information System, Supervisory Control and Data Acquisition System, Distribution Network Management System, External Website Platform, Corporate E-Mail System, Operational Data Store, Meter Management System, Customer Information System, and Enterprise Resource Planning System. The lifecycle of Tier 1 systems is generally 5 years, after which a major upgrade is required.

The Enterprise Resource Planning (ERP) upgrade and Advanced Distribution Management System (ADMS) program are two major software upgrades planned for the 2025-2029 rate period. An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. The ADMS program will ensure continued vendor support for its key components such as the Distribution Management System (DMS), the Outage Management System (OMS) and the Supervisory Control and Data Acquisition (SCADA) system that serve as the foundation of the utility's core system monitoring and operation processes. These upgrades are described in greater detail in the Expenditure Plan section of this document below (Section 8.4.4).

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information System (GIS) and the Distribution Network Analytical Tool to access important asset information across the distribution system, and to develop asset replacement plans, determine project detailed estimates and review the asset conditions prior to physical intervention.

Toronto Hydro's construction project teams and outage response teams rely on IT solutions to execute work plans and respond to outages in a timely and efficient manner. The inventory management system facilitates this function by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the

[12] Tier 2 applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications than Tier 1, and are typically supported by infrastructure with a lower complexity and lower target for overall availability.

system. A failure of this system could lead to errors in materials information, jeopardize the safety of employees using these materials, delay material delivery to project sites, hamper the utility's ability to respond to outages and execute planned work in a timely and efficient manner.

In addition, Toronto Hydro is proposing to upgrade its suite of Tier 2 IT software applications, which support targeted processes and have fewer integration points with other enterprise applications. Compared to Tier 1 applications, Tier 2 applications generally have lower maintenance costs and support a smaller user base. As such, both the operational risks and corresponding investments associated with Tier 2 software upgrades are lower than Tier 1 applications. Examples of such applications are the data analytics software, power quality application, and the fuel data system. Lifecycles developed in accordance with Toronto Hydro's Strategy are five years or less for these applications. Accordingly, all Tier 2 systems will require one or more upgrades during the 2025-2029 period.

2. Software Enhancements

Over the 2025-2029 period, Toronto Hydro plans to undertake software enhancement projects in alignment with its Strategy. Whereas software upgrades are typically triggered by vendor system support lifecycles, software enhancements are driven by risks or opportunities to improve a particular customer-facing or business process.

Toronto Hydro expects customers' and IT/OT users' demands to continue to change. In order to keep up with the pace of changes in these demands, external facing system enhancements, such as initiatives related to the web portal and customer billing will be required. Data analytics expansions could enable the development of descriptive and predictive data models to assist in areas such as long-term strategy and planning, generation and capacity planning, asset maintenance planning, outage prediction, system planning, and power quality and reliability planning.

Software Enhancements can be implemented using a variety of different IT approaches. Independent systems can be integrated to mitigate the risk of data errors and completeness. Incremental reporting capability can be built to fill gaps in management processes and decision-making. Adding new functionality or new software can expand capability to meet emerging customer needs and preferences.

3. **Regulatory Compliance**

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements and in response to emerging public policy priorities. Toronto Hydro needs to comply with regulatory requirements from a number of agencies, such as Measurement Canada, the OEB, the IESO, the Ontario Securities Commission, and the Ministry of Labour. Failure to meet regulatory compliance obligations exposes Toronto Hydro to financial risk, in the form of penalties, and reputational harm.

Between 2020-2022, Toronto Hydro implemented a number of software changes to respond to evolving regulatory compliance matters, including the OEB customer service rule amendment, Utility Worker Protection Code (UWPC) changes, and COVID-19 Energy Assistance Program (CEAP).

Toronto Hydro anticipates this policy-driven investment to continue in the 2025-2029 period.

E8.4.3.3 Communication Infrastructure

Toronto Hydro has three discrete communication infrastructure needs in the 2025 to 2029 period. Communications infrastructure is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

Reliability and availability of communication infrastructure play a crucial role in supporting the modernization of business processes to meet changes in customers' needs and preferences in response to the shift towards electrification. If the communication infrastructure used to manage the grid is unreliable, it can lead to longer power outages and operational disruptions, resulting in lower customer satisfaction. In addition, unreliable communication infrastructure will lead to increased worker safety risk and non-compliance with UWPC.

Toronto Hydro plans to undertake the following three communication infrastructure projects in the 2025-2029 period:

1. **Cellular SCADA Telecom Infrastructure Upgrade**

   In the current 2020-2024 period, the communications technology focus had shifted from proprietary SCADA radio technologies to more widely available, resilient and future proof cellular SCADA technologies. As such, cellular SCADA Telecom Infrastructure foundation has been deployed to facilitate the shift towards pole top cellular SCADA endpoints. The current version of the deployed backend cellular SCADA infrastructure will reach the end of its useful life in 2026 and will need to be upgraded to maintain security, functionality and supportability of the environment.

2. Cellular SCADA Endpoint Deployment

The current rate filing period saw the commencement of the migration of pole top SCADA endpoints from proprietary radio systems to standardized cellular technologies. In the 2025-2029 period the migration of the legacy radio system will continue, marking the end of reliance on proprietary and niche vendor radio SCADA technologies, improving the overall reliability of the environment and streamlining maintenance and support.

3. P25 Voice Radio SUA Upgrade Cycle

Motorola P25 Voice Radio system, originally deployed in 2016, provides dedicated, bi-directional voice communication channel between control room staff and field crews, enabling coordination of work efforts and ensuring worker safety. In order to keep the system operational, a series of hardware upgrades and refreshes covered by the System Upgrade Agreement (SUA) must be periodically performed to prevent system obsolescence. The upgrade of the current cycle is scheduled for 2025 and will extend the system's useful life until 2028. Another upgrade in 2029 will be required to keep the system operational until 2031.

E8.4.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IT Hardware	11.6	15.1	14.9	15.9	15.0	17.5	19.8	22.6	18.1	20.3
IT Software	22.2	26.6	42.4	42.3	38.7	38.6	40.6	41.0	33.3	34.8
Communication	3.6	2.4	0.7	1.8	1.7	3.7	2.5	0.9	6.8	1.0

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Infrastructure										
Total	**37.4**	**44.7**	**58.0**	**60.6**	**56.0**	**59.7**	**62.9**	**64.5**	**58.2**	**56.0**

Over the 2025-2029 period, Toronto Hydro forecasts spending $301.3 million across the three IT/OT Program segments. This represents an increase of $46.5 million (or approximately 18.2 percent) compared to the 2020-2024 planned spend under the IT Hardware, IT Software and Communication Infrastructure segments.

IT/OT systems perform vital functions that are central to the safe and reliable operation of the distribution system and to the effective interaction between the utility and its customers. The proposed spending is required to (i) refresh IT hardware systems at the end of their useful life (ii) upgrade Toronto Hydro's IT software applications to ensure system is current, and make targeted investments to provide software enhancements that address business risks, process improvement opportunities or compliance matters; (iii) address specific OT system needs to mitigate risks such as functional obsolescence; and (iv) maintain a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

As detailed in Exhibit 2B, Section D8, Toronto Hydro has a robust decision-making process to govern its IT/OT program. In accordance with this Strategy, the utility ranks and prioritizes initiatives in this program by weighing and balancing the following considerations and their impact on the utility's operations and customers:

- Compliance with applicable regulatory requirements;
- Alignment with the organization's strategic objectives including Grid Modernization, Energy Storage, Process Automation, Customer Experience, and Customer Engagement;
- Required availability of the IT/OT systems to support core business operations and planned work programs. As described above, enterprise software applications are categorized into two tiers based on their criticality. Upgrades to Tier 1 applications take priority over Tier 2;
- Ensuring data in the IT/OT systems are secure and protected from cyber-attacks;
- Sustaining and improving current levels of customer service; and

- Other considerations such as application complexity, resource balancing, and inter-dependencies with other programs.

A number of controls and practices are in place to ensure that IT investments deliver value to customers either directly, through improved customer service, or indirectly from performance or cost improvements. IT/OT expenditures are subject to Toronto Hydro's procurement policy, which can be found in Exhibit 4, Tab 3, Schedule 1, Appendix A. For IT software investments, this applies to both the application itself and the system integration support services that are required to implement the solution efficiently and cost-effectively. Toronto Hydro leverages existing vendors of record lists at the municipal or provincial level to secure potential volume discounts to obtain IT products at lower price points.

An independent benchmarking study performed by Gartner Consulting (Gartner) concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers.[13] Gartner also concluded that the distribution of Toronto Hydro's IT investments by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending (51.2 percent of IT spend for Toronto Hydro versus 41.9 percent for peers, largely due to the CIS Upgrade) and IT Management and Administration (14.8 percent of IT spend for Toronto Hydro versus 10.8 percent for peers, largely due to increased investment in Cyber Security services).[14]

Gartner further assessed Toronto Hydro's spending in a Run-Grow-Transform paradigm, defined as:

- **Run**: "essential (and generally non-differentiated) business processes."
- **Grow**: "improvements in operations and performance, within current business models."
- **Transform**: "new services and new operating models."

In both 2017 and 2022, Toronto Hydro IT investments were primarily directed at maintaining current business capabilities ("run") with the remainder directed at expanding existing business capabilities or driving new ones ("grow" and "transform" respectively).[15] The resulting split among the three categories is comparable to the peer group average. The increase in Toronto Hydro's 2022 IT

[13] Gartner Consulting (2023), *IT Budget Assessment Final Report* found in Exhibit 2B, Section D8, Appendix A
[14] *Ibid* at page 5.
[15] *Ibid*.

spending compared to 2017 is similar to industry peers. Toronto Hydro interprets this result as confirmation that its IT expenditures are appropriately balanced.

E8.4.4.1 IT Hardware

1. IT Infrastructure

The table below outlines the approximate volume of hardware assets for the 2020-2024 period and the 2025-2029 period. Projected cost increases are a function of higher cost-per-unit, due to hardware prices increases and higher Capacity/Unit Count which can be attributed to several factors including optimizing system performance, supporting the implementation of new IT transformation initiatives and increases in workforce. This will result in more processing power, larger storage capacity and higher network performance. Core Infrastructure units are presented in terms of Windows, Linux and UNIX virtual servers with individual unit costs reflecting the burdened cost of the entire underlying Core Infrastructure, including power, telecom, network, storage, backup, server and virtualization infrastructure layers.

Table 5: Hardware Volumes

Asset Category	IT Hardware	2020-2024 Actuals/Bridge		2025-2029 Plan	
		Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	560	47.9	650	64.3
	Linux x86 Virtual Servers	349		400	
	Windows Virtual Servers	2656		3100	
Endpoint Assets (Units)	*Personal Computing Devices*	2308	11.9	2500	13.6
	Printers & Plotters	180		130	

IT hardware cost estimates are derived by forecasting the number of hardware assets that are past their useful life and that are needed for incremental needs over the 2025-2029 period. Table 5 illustrates that the Hardware program covers the replacement of existing units of infrastructure and the expansion of numbers of units to support enhancement and transformation initiatives, with the exception of printers and plotters which decreased by 28 percent.

The Strategy details the utility's approach to replacing IT hardware assets. The timing and pacing of investment in each asset sub-type is driven by the asset lifecycle. This is defined by the applicable standard, which is based on factors such as the criticality of the infrastructure, industry best practice, and vendor specifications. These standards are designed to extract the maximum value from hardware assets and minimize the negative impact of potential asset failures.

Toronto Hydro also considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historical trends of current assets capacity versus utilization by existing IT systems;
- Asset resource requirements to support system enhancements and new initiatives; and
- New operational requirements that necessitate increased hardware resources.

Based on this approach, Toronto Hydro will require $77.9 million to replace and expand the number of IT hardware assets. Of Toronto Hydro's current assets, approximately 90 percent of existing core backend infrastructure (e.g. network, storage, and server assets) are forecast to require replacement in order to address obsolescence, security and reliability risks associated with aging assets and provide the incremental capacity needed to support Toronto Hydro's IT footprint. The utility anticipates that all endpoint assets will need to be replaced between 2025 and 2029, at a pace that will address an approximately equal number of assets each year.

The investments proposed above will provide for secure and reliable IT infrastructure, supporting all operational activities, business processes, IT/OT systems and applications of Toronto Hydro. They will enable alignment with IT Assets Lifecycle & Capacity specifications outlined in the Toronto Hydro IT architecture standards by replacing all hardware assets before the end of useful life, ensuring adequate capacity and continued vendor support. Adhering to effective asset management practices will also ensure that adequate cybersecurity posture is maintained through timely system upgrades and new technology deployments.

2. IT Cybersecurity Practice

The table below outlines the approximate volume of cyber-security controls for the 2020 – 2024 period and the 2025 – 2029 period. Projected cost increase is primarily a function of growing IT footprint and higher unit costs arising from the need for more complex cybersecurity technologies to maintain adequate cybersecurity posture in response to expected increases in emerging threats, as well as vendor price increases across the board.

Table 6: Cybersecurity Systems and Controls

IT Cybersecurity Practice	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
OEB CSF Controls & Compliance	545	12.7	600	20.2
Asset Security: Systems/Applications	1,600		1,800	
Asset Security: Endpoints	30,265		33,000	

Cybersecurity systems and controls are grouped into three distinct categories, namely the OEB Cyber Security Framework (CSF) Controls & Compliance, Asset Security Systems and Applications and Asset Security for Endpoints. These categories are inclusive of the entirety of Cybersecurity technology landscape, such as Firewalls, Intrusion Detection System (IDS), Intrusion Prevention System (IPS), Endpoint Detection and Response (EDR), Data Loss Prevention (DLP), Virtual Private Network (VPN), vulnerability management, anti-malware, anti-phishing, logging, alerting and other related systems. Costs associated with these technologies have been allocated on a per-unit basis to the ecosystem of IT systems, applications, endpoints and associated data being protected.

The investments proposed above will enable Toronto Hydro to not only maintain its cybersecurity posture at the current levels, but also develop future state readiness to adapt to the constantly changing cybersecurity threat landscape. This will be achieved through investment in advanced cybersecurity technologies, such as honeypots, attack surface management and micro-segmentation, aimed at proactively detecting and containing inherently unknown threats, such as zero-day attacks, in addition to defending against known threats.[16]

E8.4.4.2 IT Software

The table below outlines the spend for the 2020-2024 and 2025-2029 rate periods:

[16] *Supra* notes 5-8.

Table 7: IT Software Costs ($ Millions)

IT Systems	2020 - 2024 Actual & Bridge	2025 - 2029 Plan
Total Cost	172.1	188.3

1. Software Upgrades

Over the 2025-2029 period, Toronto Hydro plans to spend $188.3 million on IT software upgrades, enhancements and regulatory compliance initiatives.

As discussed in the driver's section, Toronto Hydro plans to upgrade its Tier 1 software applications. Table 8 below outlines the historical and forecast spending for the Tier 1 software applications.

Table 8: Tier 1 IT Systems Upgrades Costs ($ Millions)

IT Systems	2020 – 2024 Actual & Bridge	2025 - 2029 Plan
ERP	24.4	28
CIS	38	N/A
ADMS	N/A	34.2
Tier 1 Systems excluding ERP, CIS	41.6	46
Tier 1 Systems Total	104	108.2

a. Upgrade to SAP Enterprise Resource Planning (ERP) System

An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. [17] For instance, the ERP system can support managing inventory of equipment and supplies, scheduling maintenance and repairs, managing vendors and inbound logistics, and managing workforce. By providing a centralized and unified view of the company's operations, an ERP system helps improve decision-making capabilities, identify areas for cost savings, and optimize operations for maximum efficiency. Additionally, the ERP system enables compliance with regulatory requirements by providing tools for tracking and reporting on the company's activities.

[17] Exhibit 2B, Section E8.4, Appendix B.

Based on the Strategy, Toronto Hydro is proposing to upgrade its ERP system to the next version (i.e. S4 HANA) in the 2025-2029 period. The initiative will deliver a modern ERP system that is fully vendor supported and that effectively and efficiently executes business processes. The ERP system would strengthen Toronto Hydro's cybersecurity posture, modernize Toronto Hydro's business processes in response to changes in customers' needs and expectations due to shift towards electrification.

b. Advanced Distribution Management System (ADMS)

Toronto Hydro is looking to upgrade its current Advanced Distribution Management Systems (ADMS) which is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system.[18] Currently, Toronto Hydro operates separate instances of SCADA and Network Management System (NMS). Core operational systems are supported by a number of purpose-specific auxiliary applications, such as Automated Call-Out and voice radio communications with field crews.

Since the integration between these systems is unidirectional from SCADA to NMS, manual processes are required to keep the systems synchronized. This results in disparate user interfaces, data duplication and risk from human error.

By upgrading the existing ADMS, Toronto Hydro can achieve operational and safety excellence, enable advanced predictive and automation capabilities, implement a self-healing grid for automated outage restoration, provide automated and smart dispatching, offer holistic situational awareness, optimize distribution grid performance and customer experience, and gain full DERMS capabilities. ADMS can help Toronto Hydro manage the response to outages, meet growing customer and regulator expectations, and address the complexity introduced by the expected increase in penetration of distributed energy resources (DERs) in the electric distribution system. ADMS software analyzes data from field devices, alerts operators to adverse electrical conditions and inefficiencies, and offers advice to address these issues or performs recommended control actions automatically. These new advanced capabilities will equip Toronto Hydro with the tools required to respond effectively to future challenges associated with electrification by providing its customers with a timely and efficient outage response.

[18] Exhibit 2B, Section E8.4, Appendix A.

c. Other Tier 1 Systems

During the 2025-2029 period, Toronto Hydro plans to upgrade its other Tier 1 applications (listed in Section 8.4.3.2) in line with lifecycles developed and pursuant to its Strategy. Cost variances for these upgrades, as shown in Table 8, are primarily due to inflation.

d. Tier 2 Systems

Table 9: Planned Tier 2 Application Upgrades

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Applications	Cost ($M)	Number of Applications	Cost ($M)
Tier 2 Systems	72	12.4	80	14

The forecasts in the table above were derived by analyzing the lifecycles of all Tier 2 applications. Applications must be upgraded before reaching the end of their useful lives to mitigate the risk of failure and disruption to the business processes they support. Increasingly, vendors are reducing the lifecycles of Tier 2 applications (i.e. less than 4 to 5 years), meaning an increasing number of applications will require more than one upgrade over the 2025-2029 period. The primary drivers of the variance between 2020-2024 and 2025-2029 rate periods include the increased cost of upgrading on shorter intervals, additional Tier 2 Systems and general price inflation.

2. Software Enhancements

Software enhancements mitigate core business risks that would not be technically feasible or cost-effective to address through a non-IT solution or manual business processes. The table below presents the number of forecasted software enhancements initiatives and their associated costs in the 2020-2024 period and 2025-2029 period.

Table 10: Software Enhancements Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Enhancements	Cost ($M)	Number of Enhancements	Cost ($M)
Software Enhancements	42	45.1	55	54.6

As discussed in the Drivers section, software enhancements can take a number of different forms: adding new functionality to an existing application (aside from ERP and ADMS, which are discussed above), integrating two systems to leverage otherwise independent data sets, expanding of reporting capabilities to make better use of existing data, or adding a new application.

The increase in cost for Software Enhancements between 2020-2024 and 2025-2029 is a result of multiple factors. Toronto Hydro expects that customer and operationally-driven enhancements will be necessary to address business continuity and operational risks, respond to changing consumer preferences and shift towards electrification. Inflation also contributes to the increase in Toronto Hydro's proposed planned expenditures.

A reduction in funding for software enhancements may lead to Toronto Hydro's inability to keep pace with technology changes in the industry, and less capability to respond to emerging customers' needs and business-driven risks. The $54.6 million in software enhancements planned for the 2025-2029 plan period accounts for approximately 29 percent of Toronto Hydro's IT software segment. Toronto Hydro's total IT expenditures, of which Software Enhancements is one component, are generally consistent with its peer group in terms of the Run-Grow-Transform paradigm articulated in the Gartner IT benchmarking study (See Exhibit 2B, Section E8.4, Appendix C).

3. Regulatory Compliance

The table below presents the anticipated number of regulatory compliance initiatives Toronto Hydro will be required to complete in the 2025-2029 period and the associated budget.

Table 11: Regulatory Compliance Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Planned	
	Number of Initiatives	Cost ($M)	Anticipated Number of Initiatives	Cost ($M)
Regulatory Compliance	5	10.6	6	11.5

Toronto Hydro anticipates it will require incremental funding for new compliance-related initiatives in the 2025-2029 rate period, attributable to forecasting a similar volume of public policy initiatives driving new compliance requirements as occurred during the 2020-2024 period.

E8.4.4.3 Communication Infrastructure

Communications infrastructure is relied upon by the utility's core operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

The table below outlines the actual and forecasted volume of communication infrastructure assets for the 2020-2024 and the 2025-2029 rate periods. It is important to note as the program scope for the 2025-29 period is different than 2020-2024, the new projects are shown as separate rows at the bottom of the table below.

Table 12: Communication Infrastructure Volumes and Cost

Asset Category	Communication Hardware	2020 – 2024 Actuals / Bridge		2025 – 2029 Plan	
		Capacity / Units	Total Cost ($M)	Capacity / Units	Total Cost ($M)
Communication Infrastructure	*SONET Migration and Decommissioning*	31	3.1	0	0
	Fibre-Optic Cable	15	1.8	0	0
	SCADA High-Site Capacity Upgrade	12	0.9	0	0
	Wireless SCADA Endpoint Radio Migration	1,103	3.0	0	0
	Radio Installation	0	0	0	0
	Underground Radio Sites	0	0	0	0
	Cellular Telecom Infrastructure (initial deployment)	2	1.4	0	0
	Cellular SCADA Telecom Infrastructure Upgrade	0	0	2	1.5
	Cellular SCADA Endpoint Deployment	0	0	1,250	4.2
	P25 Voice Radio SUA Upgrade Cycle	0	0	1	9.1
	Total		**10.2**		**14.8**

As detailed in Section E8.4.3.3, over the 2025-2029 period Toronto Hydro plans to undertake work in three discrete projects in this segment:

1. Cellular SCADA Telecom Infrastructure Upgrade

Toronto Hydro expects to spend approximately $1.5 million in 2026 for this upgrade and system capacity expansion at its two data centers, facilitating future growth as the number of Cellular SCADA endpoints extends to other use cases beyond pole top RTUs, such as underground vaults and pad-mount transformers.

2. Cellular SCADA Endpoint Deployment

Toronto Hydro expects that the migration of pole top SCADA endpoints from proprietary radio systems to Cellular SCADA will be conducted in the 2025-2029 rate filing period. Toronto Hydro expects that approximately 1250 endpoints will be migrated to Cellular SCADA in the 2025-2029 period at a total cost of $4.2 million. This work will be paced uniformly from year to year over the 2025-2029 period, considering the available resource capacity to perform the migrations.

3. P25 Voice Radio SUA Upgrade Cycle

Toronto Hydro expects to perform an upgrade of the Motorola P25 Voice Radio System in 2025 at a cost of approximately $2.6 million. This is the last system upgrade, in the cycle of upgrades, under the current System Upgrade Agreement (SUA), extending the system's useful life until 2028. Toronto Hydro expects to sign a new SUA in 2028 that will keep the system operational for future years, extending its useful life and avoiding premature costly replacements. Based on provided vendor estimates the new SUA is expected to require $6.5 million of Capital expenditures between 2028-2029.

E8.4.5 Options Analysis/Business Case Evaluation (BCE)

E8.4.5.1 Options Analysis/BCE for IT Hardware Segment

1. IT Infrastructure

a. Option 1: Managed Deterioration

Choosing this option will result in a reduction of investment in the IT Hardware Infrastructure program and in IT capacity upgrades. As a consequence, IT equipment will be operated beyond its useful life and the hardware will no longer be supported by vendors. This situation can cause a significant increase in operational costs due to higher-priced extended support and insufficient IT capacity to meet key business processes. This option poses several major risks, including frequent IT service outages, reduced and eroded availability of mission-critical IT systems, and insufficient capacity to support growing data volumes and processing requirements. Additionally, using obsolete equipment may result in increased exposure to cybersecurity attacks, data loss, service unavailability, and impact to brand reputation. There is a high likelihood that this will result in software compatibility issues and jeopardize any changes, improvements and upgrades to IT Software. Unsupported hardware failures may result in data losses and the inability to recover lost data, posing an unacceptable risk to the utility's ability to provide core services to ratepayers and comply with legislative and regulatory obligations.

Furthermore, adopting this option for the rate filing period will create much greater capital and operational spend requirements in the next filing period. Toronto Hydro will need to catch up on the insufficient spend and perform major version and architectural upgrades as opposed to gradual incremental ones. This option is not advisable as it can negatively impact Toronto Hydro's ability to adequately support existing business needs, service customers and result in increased operational costs.

b. Option 2: Sustainment (Preferred Option)

Under this option Toronto Hydro will manage the IT Infrastructure program as per approved hardware standards. Opting for the sustainment option will enable Toronto Hydro to ensure consistent and reliable IT infrastructure with minimal service disruptions. By selecting this option, IT infrastructure can remain upgraded, ensuring that all assets are sized to adequate capacity with appropriate vendor support. This means that IT teams can focus on maintaining and enhancing existing systems, rather than constantly troubleshooting outdated equipment and software.

Furthermore, choosing the sustainment option enables the organization to maintain an adequate security posture by ensuring that system upgrades and new technology deployments are implemented in a timely fashion. This approach minimizes the risk of security breaches and protects confidentiality of customers’ and employees’ personal data from potential threats.

By aligning Toronto Hydro IT hardware programs with standards, it secures a nominal spend request for the next filing period. The sustainment option optimizes IT spend, avoids significant spikes in capital/operational spend and reduces overall costs. The sustainment option provides a stable and secure IT environment that allows the organization to focus on its core business activities and customer services, without increasing risks to the reliability and availability of the underlying IT infrastructure.

c. Option 3: Improvement

Under this option Toronto Hydro could provision extra capacity and enable early lifecycle replacement. Opting for the Improvement option may seem like a preferable choice to enhance IT infrastructure, but it will result in suboptimal utilization of available IT hardware resources and increased support costs. This approach does not yield any tangible benefits over the optimal selection of technologies covered in the Sustainment option. There is a high likelihood that with overprovisioned infrastructure a large number of resources are idle resulting in inefficient investment.

This approach will lead to increased operational cost burden through a larger technology footprint. Furthermore, exercising this option may lead to increased operational cost burden in the next filling period due to a larger IT hardware asset footprint.

d. Options Evaluation

The Sustainment option is the preferred option because it achieves an optimal balance that allows Toronto Hydro to maintain its IT infrastructure at an adequate level while optimizing the utility's overall IT spend. In comparison to the Managed Deterioration option, the Sustainment option provides a stable and secure IT environment that minimizes the risk of security breaches and ensures that IT teams can focus on enhancing existing systems. In comparison to the Managed Deterioration and Improvement options, this option will allow Toronto Hydro to avoid significant spikes in capital and operational spending.

In comparison to the Improvement option, the Sustainment option decrease likelihood of large number of resources being idle. By aligning with approved hardware standards, Toronto Hydro can ensure that all hardware assets are sized to adequate capacity with appropriate vendor support. This approach minimizes the sunk costs from unutilized or underutilized hardware resources. The Sustainment option secures the same security posture as the improvement option and protects confidentiality of customers' and employees' data from potential threats.

Overall, the Sustainment option provides a balance between minimizing business continuity and operational risk, optimizing IT spend, and maintaining adequate IT infrastructure.

2. IT Cybersecurity Practice

Cybersecurity practice investment options are presented in the form of Managed Deterioration, Sustainment and Improvement, with Improvement being the preferred option. Each option covers the entirety of the IT domain in terms of the number of OEB Cyber Security Framework (CSF) controls, systems and applications and endpoints that are in scope, but differ in the amount of investment into the latter two categories.

a. Option 1: Managed Deterioration

Managed deterioration option includes limited investment into the overall Cybersecurity posture, and primarily focuses on maintaining the existing controls, which may lead to the inability to maintain compliance with OEB CSF in the future. In addition, this option will effectively prevent any innovation in the Cybersecurity space resulting in gradually deteriorating security posture unable to cope with evolving cybersecurity threats.

This option carries the largest amount of risks to the environment, as suboptimal cybersecurity controls arising from inadequate investment will inevitably leave the organization vulnerable to cybersecurity threats, potentially compromising critical OT systems and sensitive customer and employee information. This will negatively impact Toronto Hydro’s ability to avoid business disruptions and ensure security and confidentiality of sensitive information. Opting for Managed Deterioration will also translate into operational spend increases due to the need to secure extended support for obsolete systems and increase future investment requirements. Due to the increased risk of cybersecurity exposure, this option is the least preferred way forward.

b. Option 2: Sustainment

Sustainment option encompasses continued investment into the Cybersecurity practice with the goal of ensuring all existing controls are managed and expanded to keep up with the evolving threats, with the intent of maintaining Cybersecurity posture at the same level as the previous filing. Investment at the sustainment level will ensure that all existing controls will continue to be adequately maintained and new functionality would be organically integrated into the threat protection ecosystem.

Sustainment option aims to maintain the level of risk consistent with the previous filing, ensuring that all systems, applications and endpoints remain adequately protected against the constantly changing threat landscape. However, this option will not reduce the risk to the organization from its current baseline, as transformative initiatives exploring cutting edge protection mechanisms would not be implemented. Due to the inherent uncertainty of the future threat landscape, maintaining cybersecurity posture at historical levels may not be sufficient to ensure adequate protection going forward. As such, Sustainment, while preferable to Managed Deterioration, remains a suboptimal option compared to the Improvement alternative.

c. Option 3: Improvement

Improvement option encompasses the increased investment into the Cybersecurity practice to enable the expansion of existing Cybersecurity threat management and response capabilities, resulting in a stronger security posture. In addition to ensuring that all existing cybersecurity controls are maintained at adequate levels, Improvement option will add new cybersecurity technologies to ensure that Toronto Hydro is capable of adapting to the continuously evolving threat landscape while reducing its risk exposure.

Improvement option aims to reduce the cybersecurity risk by implementing additional controls across IT/OT systems, applications and endpoints to ensure better ability to prevent, detect and contain threats compared to the current state. This will have the net effect of improving cybersecurity posture, resulting in better protection of Toronto Hydro’s IT/OT assets and confidentiality of customers’ and employees’ personal information while further reducing the chance of cybersecurity-related incidents and business disruptions. Therefore, Improvement option is positioned as the preferred investment option.

d. Options Evaluation

Improvement is positioned as the most optimal spend for the IT Cybersecurity practice area. Increased investment into this area will enable Toronto Hydro to handle the evolving threats of tomorrow in addition to maintaining its current cybersecurity posture and preventing technological obsolescence, ultimately reducing overall risk for the organization.

Managed Deterioration and Sustainment options are considered inferior, due to the inherent compliance, privacy and cyber security corporate risks associated with the inability to strengthen cybersecurity posture in response to the everchanging cybersecurity threat landscape. Managed deterioration in particular carries the implication of weakening cybersecurity posture and increased operational expenditures to maintain end-of-support ecosystem. Opting for either of these options would increase Toronto Hydro's liability risk at the corporate level due to elevated cybersecurity risk levels.

Failing to grow and expand the security controls protecting Toronto Hydro systems, applications and endpoints carries a high risk of negatively impacting Toronto Hydro business continuity, customer information protection, reputation and revenue generation. Toronto Hydro is governed by OEB recommended privacy and security controls, government regulations and data protection requirements. The incremental planned expenditure presented in the Improvement option aims to reduce the occurrence of future cybersecurity related incidents or business disruptions in addition to protecting its IT/OT assets, safeguarding employees' and customers' personal information, meet security compliance obligations, provide assurance to our industry partners, customers and stakeholders, and facilitate the shift towards electrification.

E8.4.5.2 Options Analysis/BCE for IT Software

1. Option 1: Managed Deterioration

The Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in the categories of Tier 1 upgrades, Tier 2 upgrades and software enhancements, with the exception of the ERP Upgrade and ADMS upgrade. This option implies that Toronto Hydro would not upgrade all its Tier 1 and Tier 2 applications according to the Strategy, increasing the risks to system reliability and availability. Toronto Hydro would need to maintain and customize these applications using manual work-arounds, which could become increasingly complex, inefficient, and costly over time. The lack of vendor support for security-related patches poses significant cyber security risks, as outdated systems would be more vulnerable to cyber-attacks and compromises. This could result in data loss, IT service interruptions, and negative impact on brand reputation.

IT software systems are essential to many critical business procedures and processes, such as the Toronto Hydro's public policy processes, safety procedures, and financial reporting. A reduction in capital spend would negatively impact all of these processes, and limit Toronto Hydro's ability to support key divisional and corporate metrics such as reliability, safety, customer service and financial indicators. Potential risks include frequent IT service outages and reduced availability of critical IT systems.

Limiting software enhancements would negatively affect business units' ability to meet their goals and objectives, potentially affecting grid operations and ability to restore power. Toronto Hydro would be unable to invest in advanced digital platforms to improve customer experience or enhance technologies to provide timely and accurate communication with customers during outages.

Moreover, there would be a significant increase in operational costs to support legacy and out-of-support systems, which would impede the organization's ability to implement systems that support future changes in business process requirements and growth.

2. Option 2: Sustainment

The Sustainment option focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications. In this option, all IT systems will be actively managed and timely upgraded. This would ensure Toronto Hydro has vendor support and it would eliminate risks to business continuity from system downtime and minimize cyber security risks. It would address compatibility risks that could arise from integrating systems that are not current.

This option will allow Toronto Hydro to meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

However, Toronto Hydro would curtail the spend in Software Enhancements to meet the spend objectives. This will limit Toronto Hydro's ability to modernize its IT business processes and address customers' changing needs and preferences in response to industry shift towards electrification. Limited funding in software enhancements would also leave Toronto Hydro unable to keep pace with technology changes in the industry.

3. Option 3: Improvement

The Improvement option balances spend across upgrades, regulatory compliance and enhancement initiatives. Similar to Sustainment option, all IT systems will be actively managed and timely upgraded. Toronto Hydro will meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

Additionally, this option will provide an optimal level of investment in software enhancements, which would allow Toronto Hydro to stay on par with its peer group.

This option will support the modernization of IT business processes in alignment with Toronto Hydro's growth and modernization strategic objectives and meet customers' changing needs and preferences in response to electrification.

4. Options Evaluation

The Improvement option is the preferred option. The Improvement option is optimal because it focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications while enabling the company to sustain its IT/OT systems and modernize its IT business processes.

Similar to Sustainment option, the Improvement option proposes all software upgrades to ensure that Toronto Hydro's software systems receive vendor support, remain integrated with other relevant software systems, are protected against cybersecurity threats.

In contrast, the Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in software upgrades and enhancements, which would leave some Toronto Hydro's IT systems without vendor support and vulnerable to cyber-attacks and compromise security. This option would negatively impact critical business procedures and processes, increase operational costs to support legacy systems, and hinder Toronto's Hydro's ability to deliver on performance outcomes such as System Reliability and Resilience.[19]

The Sustainment option proposes to sustain the status quo level of investment. However, the Sustainment option limits Toronto Hydro's ability to invest in IT enhancements, innovation and the modernization of IT business processes. In contrast, the Improvement option would allow Toronto Hydro to stay on par with its peer group and effectively respond to changing customers' needs due to shift towards electrification and future business transformation.

E8.4.5.3 Options/BCE for Communication Infrastructure

1. Option 1: Managed Deterioration

The Managed Deterioration option for communication infrastructure involves reducing investment in Communication Hardware Assets where a fewer number of wireless SCADA endpoints are

[19] Exhibit 1B, Tab 2, Schedule 1.

migrated from private radio to cellular communications. In turn, it increases operational risks and extends the time needed to complete the program. Critical SCADA communications equipment is run past the end of its useful life, resulting in obsolete hardware that is no longer supported by vendors. This can lead to higher operational and business continuity risks due to system obsolescence resulting in frequent outages, significantly increased operational costs, inability to replace faulty equipment in a timely fashion due to supply chain issues, and a lack of availability of qualified personnel to perform skilled work. Adopting this option will likely result in greater capital investment and operational spend for the period beyond 2029 to catch up on delinquent installations and upgrades, and maintain obsolete equipment past its useful life. In addition, a higher level of capital investment will be required to complete upgrades beyond 2029 due to anticipated increases in costs (e.g. inflation). This option also does not align with the organization's strategic objectives of growth and modernization as communication hardware assets will not be able to respond to changes in customers' needs and preferences associated with future industry challenges such as electrification. Limited investments in communication hardware assets will render them without vendor support, resulting in inability to perform the necessary upgrades or access patches to respond to future industry challenges.

2. Option 2: Sustainment

The Sustainment option ensures that communication infrastructure is replaced as per the Information Technology Asset Management Strategy and Investment Planning procedure, and all communications equipment remains supported by vendors. This option ensures an available and reliable communication infrastructure with little to no service disruption, resulting in minimal operational risk. In addition, the adoption of efficient and secure communications with cellular SCADA endpoints significantly reduces cybersecurity risk by ensuring an adequate security posture through timely upgrades and new technology deployments. It avoids significant increases in capital investment and operational spend, which is beneficial in the long run. The sustainment option ensures that an adequate security posture is maintained, and the risk of obsolescence is mitigated.

This option optimally aligns with the organization's strategic objectives of growth and modernization by ensuring the availability of reliable and secure communication infrastructure to sustain day-to-day operations and ability to adapt to changes in customers' needs and preferences in response to future industry challenges such as electrification.

3. Option 3: Improvement

The Improvement option for communication infrastructure involves accelerating the deployment of wireless SCADA endpoints. The utility would need to onboard additional resources on a one-time basis to fulfill this requirement. This option can help Toronto Hydro take advantage of the benefits of faster adoption of cellular communications technology for wireless SCADA endpoints. This option will require the availability of necessary specialized resources, including personnel and equipment, to meet the increased workload. As a result, there is a significant operational risk associated with securing these resources as they are not easily and readily available to Toronto Hydro and will require greater capital investment. Despite the risks, this option offers several benefits, including faster adoption of cellular technology, which can improve the efficiency and reliability of Toronto Hydro's communication services. By accelerating the deployment of wireless SCADA endpoints, Toronto Hydro can take a proactive approach to improving its communication infrastructure and enhancing the overall customer experience.

4. Options Evaluation

The Sustainment option is recommended. In comparison to the Managed Deterioration option, the Sustainment option offers a more proactive and long-term approach to ensure the reliability, availability and security of Toronto Hydro’s communication infrastructure. The Sustainment option also ensures communication infrastructure assets are upgraded as per Information Technology Asset Management Strategy and Investment Planning procedure and remain supported by vendors. This option ensures alignment with modernization by enabling system growth and preventing the risk of obsolescence, service disruption, and cyber-security threats. The Managed Deterioration option involves limited investments and extending the time needed to complete the upgrade, which can result in increased operational risks and frequent outages.

The Improvement option for communication infrastructure offers benefits such as faster adoption of cellular technology and improved efficiency and reliability of communication services. However, it poses high operational risks due to significant uncertainty in ensuring the availability of personnel and equipment resources to complete the extra work and greater capital investment.

The Sustainment option offers an optimal balance between investment required and operational risk management, ensuring that Toronto Hydro's communication infrastructure remains secure, reliable, and adequately supports future business requirements. Therefore, the Sustainment option is the preferred option.

E8.4.6 Execution Risks & Mitigation

This section discusses various potential risks to the execution of the IT/OT program, and Toronto Hydro's corresponding mitigation measures:

- **Cybersecurity Threats:** Even with a strong cybersecurity posture, it is possible for cyber threats to impact a company's ability to execute the IT/OT program on time and within budget. To mitigate these risks and minimize the associated impacts, Toronto Hydro developed incident response and business continuity plans to address potential disruptions caused by cyber threats. Mitigation strategies include employing backup systems, implementing redundant infrastructure, and sourcing alternative suppliers or vendors.
- **Regulatory Requirements:** Implementation of new regulatory requirements may require more resources and time than budgeted. If new regulatory requirements emerge at a higher than expected rate, resources will be re-allocated accordingly to ensure that Toronto Hydro complies with application requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations outlined in section E8.4.4.2 above.
- **Software Release Dates:** Changes to application version release dates will impact the project schedule and potentially impact downstream projects in the program. If one or more software upgrades require another software upgrade to be completed first, any delay in the release of the first software upgrade will delay the upgrade of the dependent software system(s). To address this risk Toronto Hydro monitors release dates, ensures that all impacted projects are properly sequenced and maintains a holistic view of IT environment/architecture to identify interdependencies.
- **Technology Change:** New technology may be introduced after previous assets were refreshed during the asset's lifecycle. This risk may impact project cost, as new technology may need to be procured to meet business requirements. Toronto Hydro closely monitors the latest trends to determine how technology fits into existing Toronto Hydro IT standards and business requirements. In addition, Toronto Hydro assesses and evaluates future IT

investments to ensure preparedness to respond to future challenges such as electrification and align with the organization strategic objectives.

- **Solution Fit to Utility Requirements**: A design approach that considers functionality in isolation is particularly risky. The solutions proposed for incorporation into the upgraded and expanded IT systems must be able to deliver the functionality Toronto Hydro requires to meet its operational, regulatory, and customer obligations. Toronto Hydro will fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements will be defined and documented by Toronto Hydro prior to tools, components and modules selection, and integration. End-to-end operational process scenarios will be used in the testing phase of the system.
- **IT/OT Systems Integration:** Different systems may not properly integrate with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded and process inefficiencies could be introduced from manual data updates. Toronto Hydro considers and analyzes new component configurations in defining project scopes, and conducts thorough due diligence during technical feasibility studies.
- **Internal Resource Availability:** There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, Toronto Hydro will: (i) adopt a long-term resource plan based on required skills to support project tasks and activities that the utility plans to undertake over the 2025-2029 period; (ii) train and cross train resources to ensure employee engagement, employee retention and workforce sustainability; and (iii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.
- **Vendor Management:** Vendors may not meet program delivery obligations or may change the product cost structure. More specifically, a vendor may be unable to provide the product according to project schedule or in compliance with Toronto Hydro's specifications, thereby leading to delays or cost overruns to address the issue. In this regard, Toronto Hydro will ensure mechanisms are available to oversee and enforce contract terms and conditions. Toronto Hydro will adopt the following mitigation measures within its contracts:

  - Complete comprehensive due diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation.
  - Solicit vendor responses to competitive bids from qualified parties.
  - Enter into long term contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time.
  - Clearly state expected timelines and have resolution clauses to address delays.
  - Identify an escalation path to quickly resolve conflicts and discrepancies.
  - Enforce short interval control on vendor performance and deliverables through project status updates.
- **Adherence to Budget & Timelines:** If a project tracks above budget or falls behind schedule, this could take resources away from other important IT projects and delay their implementation. To address this risk, Toronto Hydro uses modern project management methods, tools, and vendor agreements to ensure on-time and on-budget project execution. Moreover, Toronto Hydro's experienced project managers will control the implementation timing of projects in accordance with each project plan and closely monitor emerging risks. Contract tools and incentives will also be incorporated to aid the management of timelines.
- **Project Delivery**: A new IT/OT System version could cause established core business processes to change and, without proper integration, could disrupt, and cause inefficiencies in these processes. Toronto Hydro undertakes extensive regression testing and user testing prior to rolling out the final upgrade to the business units. In addition, risks are mitigated through appropriate user engagement and communication, change management, training and project governance including contingencies to minimize the impact to the business users in the final implementation.

Preliminary Scoping Business Case:

Advanced Distribution Management System (ADMS) Upgrade

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1. EXECUTIVE SUMMARY

Project Name	Costs (2025-2029)
Advanced Distribution Management System (ADMS) Upgrade	$34.2 million

Toronto Hydro relies on its current ADMS to meet service quality requirements and maintain the reliability of the distribution grid. The ADMS is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system. Key components of ADMS include:[1]

1. the Distribution Management System (DMS);
2. the Outage Management System (OMS); and,
3. the Supervisory Control and Data Acquisition (SCADA) system.

These three systems are the foundation of the utility's core system monitoring and operation processes. DMS and OMS enable operators to manage critical functions such as the identification and response to outages, and the safe planning and execution of field work using planned or emergency switching, combined with other elements of the Utility Work Protection Code (e.g. Work Permits, Supporting Guarantees, Hold Offs etc.). These systems are essential to supporting the evolving needs of Toronto Hydro's distribution grid and its users as a greater number of households, businesses, and government organizations electrify their energy usage, and as the penetration of distributed energy resources (DERs) increases. ADMS software, in particular SCADA, analyzes information acquired from field devices, alerts system operators to adverse electrical conditions, possible inefficiencies, and reliability issues, and either assists operators in addressing these issues or performs recommended control actions automatically.

Given the criticality of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades to the ADMS to ensure continued vendor support are necessary to ensure business continuity and adequate protection from existing and emerging cyber security threats. In addition, many ADMS components currently operate in silos and have limited ability to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in longer outages. Upgrades to ADMS will enable effective co-ordination and communication among its various components by allowing Toronto Hydro to hand pick components in order to achieve a synchronized and harmonious platform. These upgrades will also align with the utility's grid modernization objectives by supporting future automation functionalities (e.g. in support of the self-healing grid) and improving business process efficiencies through leveraging technical and functional enhancements.

[1] A detailed list of components is available in the Appendix

Upgrades to ADMS will also enable Toronto Hydro to continue to meet or exceed the Ontario Energy Board's (OEB) reliability performance standards, particularly the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). ADMS contributes to grid reliability by providing Control Centre operators the capabilities to monitor and control the distribution network in real-time and enabling a comprehensive view of the network status of all connected devices including transformers, breakers and switches. It also contributes to the achievement of service quality requirements by enabling the automatic location and isolation of faults through the Fault Location, Isolation, and Service Restoration (FLISR) function, which reduces outage response times. ADMS is also equipped with advanced diagnostics to analyze the health of the distribution system and to identify outage root causes faster.

To ensure an effective ADMS solution for Toronto Hydro, the following options were assessed:

1. **Managed Deterioration** - Maintain status quo with current ADMS software platform.
2. **Sustainment** - Maintain status quo and execute only reactive and mandatory changes to keep the ADMS systems current without undertaking an upgrade.
3. **Modernization and Growth -** Implement a modern ADMS platform by leveraging the advantages of each system in a "Multiple Vendor Approach" strategy (i.e. "best fit" vendor offerings to meet Toronto Hydro's business needs).
4. **Replacement and Harmonization** - Implement a single platform, migrating all OMS, DMS, SCADA, and Distributed Energy Resource Management System (DERMS) functionality to the one integrated vendor.

The utility evaluated each option against the following categories:

- **Strategic Risks –** Each option was evaluated for alignment with strategic criteria which included alignment with Toronto Hydro's strategic objectives such as intelligent grid, grid modernization and process automation.
- **Tactical Risks**: Each option was also evaluated against tactical considerations including operational risk, security risk, implementation risk, timeline risk and budget risk.

Based on this evaluation, Modernization and Growth is the preferred option. This option positions the utility well to ensure grid reliability, alignment with Toronto Hydro's strategic objectives, the modernization of the utility's operations, and the improvement of customer experience. In addition, this option will assist Toronto Hydro in achieving its strategic objectives.

The Modernization and Growth approach will leverage multiple vendors to identify components that best fit Toronto Hydro's needs, and ensure compatibility and effective communication between different components in order to develop a synchronized platform. This approach also enables the utility to implement planned enhancements more effectively and flexibly based on functional phases that target specific areas such as FLISR, SCADA, DERMS, etc.

The intended benefits of the ADMS Upgrade are to:

- Ensure critical operational technology platforms are fully supported by respective vendors and are resilient against cyber security threats;
- Achieve operational and safety excellence;
- Enable advanced predictive and automation capabilities to reduce the frequency and duration of outages, resulting in improved system reliability and customer experience;
- Improve grid resiliency through automated and efficient restoration of outages with minimal interruption to customers;
- Deliver streamlined and effective responses to outages with crews addressing outages more quickly in the field through automated and smart dispatching;
- Leverage new technologies to enhance the utility's ability to assess and prioritize responses to outages due to major events such as storms through a holistic view of the grid;
- Ensure optimal distribution system performance and improve customer experience;
- Enable better monitoring and control of distributed energy resources in the field; and,
- Ensure optimal utilization of IT assets by enabling effective lifecycle management of secure and supported systems, minimizing operational and cyber security risks.

2. PROBLEM/OPPORTUNITY STATEMENT

2.1 Background

The upgrade of Toronto Hydro's Advanced Distribution Management System (ADMS) platform is necessary to enable the utility to maintain and modernize critical distribution system monitoring and management processes into the 2025-2029 rate period and beyond.

Current functions and components of ADMS allow Toronto Hydro to execute a variety of processes relating to the monitoring, operation, maintenance, and general oversight of the distribution system, such as:

- identifying outages;
- scheduling responses by field crews or remotely operating components of the grid to restore outages;
- monitoring and controlling DERs connected to the grid;
- performing various tasks in support of capital or maintenance work (such as switching); and,
- coordinating the management of the utility's distribution system in alignment with the operation of the bulk transmission grid by Hydro One and the Independent Electricity System Operator (IESO).

All of these functions are essential in enabling the utility's compliance with legislative and regulatory obligations relating to customer, public, and worker safety, grid reliability, and customer service.

Toronto Hydro plans to renew the systems comprising these functions and components of ADMS during the 2025-2029 period in order to 1) ensure that vendor support remains current and available and 2) enhance ADMS with various upgrades that will improve the effectiveness and efficiency of the underlying processes. The utility expects that its planned enhancements to ADMS will be crucial for operational effectiveness as society moves towards decarbonization, increasing the pace of electrification, and as the nature and needs of customers and stakeholders interacting with Toronto Hydro's distribution system continue to evolve.

The proposed upgrade would also present opportunities for the utility to streamline the operation and integration of ADMS functions and components and manage the relevant information and operational technology (IT/OT) assets in a more cost-effective manner, in accordance with

Toronto Hydro's IT Asset Management and Investment Planning Strategy (the Strategy).[2] In addition, ADMS upgrades will provide a comprehensive path for managing assets as per the Strategy by enabling effective tracking, utilization and co-ordination among various components. Given the rapid advancement in technology, without the ADMS upgrades, current systems will begin losing access to new and existing features, security will become a greater risk and vendor support will become more difficult to maintain. In addition, ADMS is a dynamic integrated platform that depends on all components working together in a synchronized fashion. Currently, not all ADMS components can be fully integrated to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in an increase in outage response times. Integration will become increasingly important as the components age and component capabilities change, resulting in gradual degradation in ADMS' ability to perform critical activities. Upgrades to ADMS will enable effective co-ordination and communication among its various components by handpicking components from multiple vendors in order to achieve a synchronized platform, enabling the utility to provide a timely and effective response to outages.

2.1.1 Application Components

Toronto Hydro's ADMS platform includes the following current operational functions (listed with possible enhancements to each function through the ADMS Upgrade project):

- Distribution Supervisory Control and Data Acquisition (SCADA) system – Enhance integration with other ADMS components and introduce more automation.
- Outage Management System (OMS) – Increase monitoring capabilities across the grid, improve productivity by automating simple dispatch transactions, and optimize the utilization of Control Centre and field resources.
- Distribution Management System (DMS) – Provide more detailed and up-to-date visibility into grid conditions.
- Distributed Energy Resource Management System (DERMS) - Enable more precise monitoring and control of distributed energy resources connected to the distribution grid.
- Overall Enhancements - Interfaces to other internal and external systems such as Toronto Hydro's Geospatial Information System (GIS) and corporate data historian, Hydro One's energy management system (EMS), and others.

2.2 Problem Statement

As previously noted, the ADMS platform is critically important to the execution of Toronto Hydro's day-to-day operations and compliance with applicable legislative and regulatory obligations

[2] EB 2023-0195, Exhibit 2B, Section D7

relating to customer, public, and worker safety, grid reliability, and customer service. The following subsections provide more details on the risks that may arise in the event that the utility does not upgrade the ADMS platform in the 2025-2029 period.

2.2.1 System Risks: Infrastructure Lifecycle

Although the current ADMS infrastructure is fully supported and optimized for existing systems, the current application and database servers are forecasted to reach end of life by 2027. Operating these assets beyond end of life would require Toronto Hydro to establish backup infrastructure that is not optimized to accommodate ADMS components and to procure specialized technical resources for maintenance purposes. These mitigation measures could cause further risks affecting the reliability of ADMS and the continuity of distribution operations. For example, if issues with the ADMS infrastructure were to materialize, the utility will have limited ability to ensure the solution will work on an outdated infrastructure. This, in turn, may present a greater risk to restoring full functionality following infrastructure failures in a timely and effective manner, jeopardizing Toronto Hydro’s ability to effectively monitor and manage the distribution system.

2.2.2 System Risks: Cyber Security Protection

The systems that currently comprise the ADMS platform receive regular service packs and patches from their respective vendors, including occasional ad hoc security patches to address any critical vulnerabilities. This approach ensures that the systems remain up-to-date with the most current features and are protected against cyber security risks. However, as ADMS systems age and lose vendor support, Toronto Hydro will no longer have access to these timely updates and patches, resulting in greater exposure to cyber security threats and putting at risk the continuity and integrity of the critical functions supported by ADMS systems.

2.2.3 Business Continuity Risks

Based on Toronto Hydro’s past experiences, various vendors will discontinue future investments in product updates, functional enhancements, and technical improvements in respect of the systems that currently comprise the ADMS platform, as early as 2024. If the utility is consequently unable to keep up with product standards and improved functionality, these developments may result in significant risks to the continuity, efficiency, or timeliness of critical business operations in support of outage restoration and capital and maintenance work. In addition, continuing the use of obsolete products would hinder the utility’s ability to modernize its business processes in accordance with the evolving nature and needs of customers and stakeholders interacting with the distribution system, for example due to electrification. Deferring system upgrades may require Toronto Hydro to deploy alternative solutions in the meantime, which may be less effective in maintaining business processes. Furthermore, as the gaps in capabilities of different ADMS components continues to grow, the utility’s ability to have these components operate in a coordinated and effectively integrated manner will become increasingly difficult, posing significant risks to process continuity, system reliability, and the effectiveness of reactive solutions. Collectively, these risks may cause adverse impacts beyond Toronto Hydro and its service territory, for example by hampering the utility's obligations to support outage restoration and participate in bulk system event management tasks in accordance with the IESO's Ontario Power System Restoration Plan.

2.2.4 Lost Efficiencies and Opportunities of Process Automation and Innovation

As the number of connections to the distribution system increase due to electrification and the nature of connections become more diverse through increased uptake of DERs, Toronto Hydro will need to invest in its tools and processes to efficiently perform both traditional system management and outage restoration tasks and emerging functions such as DER monitoring and control. Achieving continuous improvement and productivity gains in these areas will require the utility to increasingly focus on process automation and innovation. The proposal to upgrade ADMS components and other integrated systems incorporates a number of enhancements that will enable such automation and innovation, as described in greater detail in sections 3 and 5 of this document.

Without the ADMS upgrade, Toronto Hydro would lose the ability to benefit from improved product functionalities that would enable automation and associated productivity and efficiency gains. This would greatly hamper the utility's ability to achieve favourable outcomes for ratepayers, including its strategic objectives (e.g. intelligent grid, grid modernization and process automation), and to implement key technologies and initiatives that underpin the utility's modernization plan for the 2025-2029 rate period, such as FLISR.

Currently many ADMS components have limited integration with each other, hindering effective communication between systems. As these components age, the integration gaps between them will likely grow. In the future, this may impede effective decision-making and operations by Toronto Hydro and consequently affect the utility's overall efficiency. The proposal to upgrade ADMS components provides an opportunity for the utility to enable effective coordination and communication between the platform's systems by handpicking the most optimally integrated solutions.

2.2.5 Summary

In summary, Toronto Hydro expects the ADMS upgrade to add value and address risks relating to the following areas:

- ✓ **Monitoring the distribution system:** ADMS provides the utility with a real-time network model. Without it, Control Centre operators would lack an efficient and reliable way to understand the state of the distribution system. Furthermore, as DER penetration increases, the utility may need greater visibility into system parameters (e.g. DER outputs, power flows, localized voltage and current, etc.) to better monitor and manage the safety and reliability of the grid.

- ✓ **Responding to all emergencies in accordance with legislative and regulatory requirements:** Improvements to OMS and other components would enhance the utility's ability to efficiently identify and prioritize grid emergencies.
- ✓ **Outage restorations:** The implementation of enhanced automation and system aided switching through components such as FLISR would be critical to achieving continuous improvement in the utility's ability to prioritize and schedule actions to restore power and remedy outages.
- ✓ **Dispatch and grid response functions:** Solutions such as automated dispatching and route optimization would enhance the utility's decision-making and organization processes for assigning Control Centre and field resources to both emergency response and planned activities.
- ✓ **Safety:** Enhanced functions under ADMS would facilitate compliance with safety requirements (e.g. under the Utility Work Protection Code) and enable effective auditing of relevant records.
- ✓ **Grid Analytics and System Planning:** Upgrades to the ADMS would supply the utility with more sophisticated tools to proactively monitor the grid performance, analyze opportunities for improvement, and effectively plan for actions and investments to improve grid resilience and capacity. Furthermore, such solutions would be more responsive to challenges posed by increasing volumes and types of DERs such as battery storage, electric vehicles, and distributed generation.

3 BUSINESS REQUIREMENTS SUMMARY

This section provides a high-level summary of the requirements for the ADMS upgrade to meet business needs and align with strategic objectives. A detailed list of functional requirements can be found in Section 5, the Appendix to the Business Case document.

As this business case is described at a program level, this may lead to multiple phases and releases that will encompass it. As such, considerations such as execution strategy will help determine the prioritization of the below requirements.

ADMS Requirement Categories	High Level Requirements
Intelligent Grid	• Automated FLISR/Self-Healing Grid - Automatically operating devices in the field to restore power to customers and minimize outage duration. • Improve outage resolution by leveraging fault location analytics (FLA) capabilities which use real time data and predictive algorithms that makes outage restoration more efficient • Gather real-time grid data via SCADA to help identify grid weaknesses and assist with evaluating level of outage risk • Improve the quality and reliability of field data available to Control Centre operators and meet reliability performance targets • Support remote terminal unit (RTU) testing • Support multiple communication protocols, standards and data acquisition techniques • Support multiple control actions • Exchange data with other systems in real time
Process Automation	• Enable automation where possible within dispatching to improve execution of planned and un-planned activities • Introduce training simulator for staff to improve the management of storm events

Customer Experience	• Improve outage management processes to achieve:
	  o Greater situational awareness regarding outages
	  o More accurate and timelier provision of estimated times of restoration and outage map updates
	  o More effective damage assessment leading to faster outage resolution

ADMS Requirement Categories	High Level Requirements
	○ Improved grid response processes to restore power to as many customers as possible, as quickly as possible
IT Asset Management	• **System Currency** - Keep up to date with system upgrades and retain effective system support • **Cyber Security** - Ensure security risks are identified and mitigated or minimized by aligning with industry and technological best practices • **Performance** - Ensure appropriate level of performance that allows the efficient use of system tools by all system users, particularly during storm situations • **Improved release management** - Take advantage of system solutions that support high availability, resulting in fewer planned IT system outages.

*Detailed list of requirements is available in Appendix

3.1 Assumptions & Dependencies

The following assumptions underpin the scope of the ADMS Upgrade project. Any change in the assumptions will require a reassessment of the project scope, timelines, and costs.

- The existing integration between various ADMS components will remain intact until a new specific ADMS system component goes live.
- Other non-ADMS systems (e.g. GIS, the Customer Information System, etc.), impacted by the project will remain unchanged until a new specific ADMS component goes live.
- No new and major technological developments that impact ADMS and its underlying infrastructure will emerge for the duration of the project.
- No new and major functional or technical requirements will emerge for the duration of the project.
- There will be no change in the organizational direction to the overall project approach as described in this Business Case document.

4. OPTIONS ANALYSIS AND RECOMMENDATION

Toronto Hydro engaged various internal and external stakeholders to evaluate a number of options to address the problems and opportunities outlined in Section 2 of the Business Case.

The utility considered available solutions and processes to identify challenges and opportunities, and to establish baseline requirements and objectives.

The utility also invited industry leading ADMS vendors to showcase their solutions, which allowed the evaluation of new technologies against existing and future business needs, the refinement of product evaluation criteria, and the identification of additional requirements and considerations.

This exercise helped Toronto Hydro in identifying the four options discussed below. The utility assessed these options against the evaluation criteria presented in Subsection 4.2, ensuring alignment with applicable strategic objectives and IT/OT standards. The following subsections provide details of the options considered and the rationale supporting the selected option.

4.1 Options Analysis

Option 1 – Managed Deterioration

In this option, Toronto Hydro will continue to work with existing ADMS systems with no enhancements, upgrades, new integrations, or patches. The utility will continue to run systems past their end-of-life and address defects on a best efforts basis only, with the limited capabilities available.

As this option focuses solely on maintaining status quo with respect to existing systems, it represents the least expensive option in terms of upfront capital investments and initial operational costs. However, this option poses a high degree of risk due to degrading system performance and system currency as well as increasing cyber security concerns. This option would eventually result in a gradual degradation of operational capabilities due to decreasing levels of vendor support for current systems. From a cyber security standpoint, this option would lead to increased vulnerability to cyber attacks due to the lack of vendor-supplied security patches, increasing the likelihood of more frequent and severe disruptions in day-to-day operations. Ultimately, this is not a sustainable option, as it would lead to significant deterioration of operational resiliency.

The increasing operational and security risks that would accumulate over time under this option far outweigh the low implementation costs, and budget and timeline risks. Over time, the utility's inability to address system vulnerabilities may lead to increases in cyber security breaches and a subsequent decrease in business process efficiencies. Limited and degrading vendor support and maintenance can also lead to longer and more frequent system breakdowns of ADMS systems, hampering distribution system management and operations and resulting in lower customer satisfaction and inability to meet legislative, regulatory, and performance requirements relating to safety and reliability. In addition, resourcing legacy applications is challenging. Currently, ADMS technical resources are focusing on updating their skill sets for new ADMS component versions, which shrinks the pool of resources that will be available in the future to support legacy applications. Externally, ADMS vendors will shift their support pool to the latest versions and support for legacy versions will become increasingly limited or unavailable after 2028.

Finally, this option does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would continue running its current systems past the point of obsolescence. This outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains, and leave Toronto Hydro's distribution system ill-prepared to meet the challenges presented by evolving consumer preferences and industry conditions, such as electrification or increasing DER uptake.

Option 2 – Sustainment

In this option, Toronto Hydro will maintain status quo with respect to existing systems, and be able to sustain day-to-day operations, in a limited capacity, by relying only on the minimum infrastructure, application upgrades, and security and system patches, for as long as they are available.

This option has the advantage of low up-front capital expenditures and would only require minimal investments in change management actions required to sustain the utility's day-to-day operations. However, over time this may result in increasing operational costs associated with obtaining vendor support and having to manage greater exposure to cyber security threats. While this option would maintain short term system currency and operational resiliency, Toronto Hydro would find it increasingly difficult and costly to sustain old technologies with fewer upgrades and patches from declining vendor support to maintain adequate levels of security and system reliability. The inefficiencies from the lack of integration between legacy systems would continue and attempting to integrate them further as they age would be costlier and carry a higher chance of system failure.

This option also does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would only maintain currently available functionalities. Without access to new features and functions, current systems may be unable to adapt to customers' evolving needs and preferences in to the context of emerging industry trends such as electrification or increasing DER uptake. In addition, this outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains.

Option Three – Modernization and Growth (Recommended Option)

In this option, Toronto Hydro will implement a modern ADMS platform by upgrading its component systems and leveraging the advantages of each system through procurements with multiple vendors, which would allow the utility to acquire the most optimal technologies for OMS, DMS, SCADA, and DERMS. This option will involve upgrades to the latest version of each specific system, while continuing to enable more advanced capabilities such as FLISR and artificial intelligence with an agile implementation approach.

Furthermore, this option will allow the utility to achieve targeted benefits using a phased approach. By relying on multiple vendors and workstreams, Toronto Hydro can realize benefits as each project phase is completed. This option will also take advantage of new technologies and vendor solutions that will address the risks outlined in subsection 2.2 and meet the business requirements outlined in section 3.

This option will require moderate capital expenditures for implementation and relatively higher operational costs to maintain multiple systems and vendors, as well as user training and knowledge base management across several different platforms. However, the incremental operational costs would be partially offset thanks to lower needs of operational change management, through the proposed strategy of upgrading current systems on an ongoing basis. In the long term, this option would also allow Toronto Hydro to holistically balance and optimize project costs (capital and operational) and business units' operational costs by pacing and tailoring the selection and implementation of particular upgrade solutions in accordance with the urgency of business needs, rather than having to invest in all system upgrades all at once under a one-vendor approach.

This option would maintain vendor support through the proposed system upgrades and consequently result in lower cyber security and operational risks, as access to vendor-supplied enhancements, upgrades, and, patches would serve to strengthen the organization's cyber security posture and reduce the likelihood of operational disruptions.

This option would also allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components. The multiple vendor approach would enable the utility to procure solutions in a more flexible and customized manner in accordance with the business needs underlying each upgrade. These solutions, in turn, would yield process efficiencies and productivity gains (e.g. through the implementation of FLISR and the self-healing grid), and put Toronto Hydro in a much better position to respond to emerging industry trends such as electrification or increasing DER uptake. Finally, this option would provide opportunities to improve integration and communication among ADMS' various systems by handpicking components from multiple vendors to achieve a synchronized platform, laying the groundwork for future enhancements.

Option Four - Replacement and Harmonization

In this option, Toronto Hydro will migrate all OMS, DMS, SCADA, and DERMS functionalities under one integrated vendor. This option would pose significantly higher change management risks as all business processes currently dependent on ADMS systems would require modifications and some of the previously integrated enhancements would require re-implementation under the selected vendor's solutions. This option would offer several benefits from the adoption of a single integrated system such as uniform user experience, lower integration and ongoing sustainment costs. However, these benefits would be offset by the higher up-front capital investment required to redo and redesign unique customizations and configurations. In addition, this option will require significant retesting and extensive change management including user retraining, changes to operational procedures and related documentation, employee communications, all contributing to longer implementation timelines. Realizing the benefits of the system upgrades would take approximately 2-3 years longer than under Option 3 due to the migration to a single platform. Implementation would also be subject to higher timeline and budget risks due to reliance on a single vendor. Finally, to the extent that this option were to require the early replacement of any ADMS component before end of life, it would result in suboptimal utilization and value from previous investments, to the detriment of ratepayers.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following strategic criteria:

1. **Alignment with Strategic Objectives:**
    a. Intelligent grid & grid modernization
    b. Process automation
    c. Customer choice
    d. Customer experience
    e. IT asset management
2. **Grid Reliability**: Measure of ADMS systems' ability to support operational processes feeding into grid reliability, distribution during peak times for electricity use, the reduction of outage durations, and the automation of outage response.
3. **Cyber Security**: Overall assessment of cyber security configuration and capabilities.
4. **Environment and Safety**: Concurrence with legislative and regulatory obligations and utility and industry standards relating to health and safety.

5. **Change Management**: Amount of effort required to prepare and enable the organization and users to adapt to the new systems/processes
6. **Cost**: Overall implementation and sustainment costs
7. **Timeline**: Overall timeline to project completion and the achievement of projected benefits
8. **Overall Risk:** Denotes the holistic assessment of previously described strategic risk categories

The utility assessed each of the above strategic risks under the four options as follows.

Table 1: Evaluation of Strategic Risks

Options/Criteria	Alignment with Strategic Objectives	Grid Reliability	Cyber Security	Environment and Safety	Change Management	Cost	Timeline	Overall Risk
1. Managed Deterioration								
2. Sustainment								
3. Modernization and Growth								
4. Replacement and Harmonization								

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

Toronto Hydro also evaluated each option based on the following tactical criteria:

1. **Operational Risk:** Risk of disruption to the day-to-day business activities of the utility
2. **Security Risk:** Cyber security and other types of security risks
3. **Implementation Risk:** Risk of challenges to system/project implementation due to difficulty and/or complexity
4. **Timeline Risk:** Risk that project tasks and deliverables will take longer than forecasted
5. **Budget Risk:** Risk that costs for the project will be higher than forecasted due to unexpected expenses, delays, or increases in scope

Table 2: Evaluation of Tactical Risks

Options/Criteria	Operational Risk	Security Risk	Implementation Risk	Timeline Risk	Budget Risk	Overall Risk
1. Managed Deterioration						
2. Sustainment						
3. Modernization and Growth						
4. Replacement and Harmonization						

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

As outlined in subsections 4.1 and 4.2, Toronto Hydro is recommending the Modernization and Growth option (option 3). This option will enable Toronto Hydro to continue attaining the benefits offered by the ADMS platform by keeping its systems current and its vendor support intact, while also unlocking future benefits in support of grid modernization and process automation in the most flexible and cost-effective manner.

The Modernization and Growth option positions the utility well to meet a range of grid reliability and health and safety outcomes by maintaining the key ADMS systems supporting relevant business operations and enabling their continuous improvement. Although the Replacement and Harmonization option will also contribute to reliability and health and safety outcomes, the previously discussed implementation challenges associated with that option may put those outcomes at risk. While the Sustainment option also serves to maintain the status quo with respect to reliability and safety criteria, it is unlikely to provide optimal support for reliability and health and safety outcomes (e.g. employee and public health and safety, compliance with relevant legislative and regulatory requirements) in the long term as this option will restrict ADMS system upgrades to the bare minimum. The Managed Deterioration option represents the most significant risk to reliability and health and safety outcomes, as the deterioration of ADMS systems and the lack of vendor support would greatly increase the likelihood of disruptions to the related business processes depending on ADMS.

Due to the increasing number and sophistication of threats, cyber security continues to be a growing concern for many utilities. The Managed Deterioration option ranks the lowest in this regard as the deterioration of ADMS systems and the lack of vendor support under this option would greatly increase cyber security risks. Although maintaining the status quo under the Sustainment option allows the system to maintain the existing level of protection from cyber security threats in the short run, restricting system upgrades to the bare minimum overtime will hinder the utility's ability to ensure adequate protection of the ADMS platform against threats in the evolving cyber security landscape. Both the Modernization and Growth option and Replacement and Harmonization options would position the utility well against current and emerging cyber security threats through the system upgrades contemplated under those options.

The Modernization and Growth option supports the adoption of emerging technologies and new functions which align with Toronto Hydro's grid modernization and process automation initiatives (e.g. through the implementation of FLISR and the self-healing grid). Although the Replacement and Harmonization option also aligns with these strategic objectives, it is a suboptimal solution because of the lack of flexibility resulting from the single vendor approach contemplated under that option. In order to leverage the technology solutions that best-fit the utility's business needs and enhance the overall customer experience, Toronto Hydro adopted a multiple vendor approach under the Modernization and Growth option. This option also contemplates the achievement of better integration and communication among ADMS' various systems, it is well-poised for enabling future enhancements, despite the greater diversity of systems and components compared to the Replacement and Harmonization option. In contrast, the restricted approach to system upgrades under the Managed Deterioration and Sustainment options will hamper the utility's adoption of new technologies and functions in alignment with strategic objectives, jeopardizing the evolution of underlying business processes.

With respect to change management, timelines, and budget, the Managed Deterioration option fares best, as it would minimize capital expenditures, change management activities, and execution risks. The Sustainment option also presents a lower risk profile with respect to these criteria. For example, in the short term the need for change management would be minimal from maintaining existing systems. However, in the long-term Toronto Hydro would find it increasingly difficult to maintain current systems as they reach end of life and vendor support diminishes. Ultimately, both the Managed Deterioration and Sustainment options involve other types of unacceptable risks and shortcomings that offset the relatively lower change management, timeline, and budget risks. The Replacement and Harmonization option is the least favorable in terms of change management, timelines, and budget, as implementing a single vendor solution to meet all functional needs would likely require higher up-front capital costs and more extensive change management, resulting in longer implementation timelines (See Section 4.1 for more details). The Modernization and Growth option represents the optimal balance with respect to these criteria as it would holistically mitigate financial and operational risks by leveraging individual vendor capabilities through competitive procurement and implementing smaller, targeted initiatives over multiple phases instead of larger and more complex initiatives during a shorter period of time. Under this approach, Toronto Hydro would also retain the flexibility to implement better integration and communication among ADMS' various systems. In this sense, the Modernization and Growth is also the option that best aligns with Toronto Hydro's IT Asset Management and Investment Planning Strategy.

In implementing the Modernization and Growth option, the first step would be the discovery and documentation of the current state and detailed business and technical requirements. Then, Toronto Hydro would assess each requirement and design a suitable solution. This process would likely involve multiple steps as different system upgrade projects are awarded to different vendors. The utility expects the majority of the work and costs to occur in the various implementation phases.

Under this option, the ADMS Upgrade would constitute multiple projects with different delivery dates. This would enable Toronto Hydro to realize the benefits of each element as it is implemented as some of the planned system upgrades and enhancements would benefit from synergies with current initiatives in the 2020-2024 rate period. In addition, multiple projects will be run simultaneously by multiple teams working in parallel as opposed to a single team working on each phase of a project one at a time. This approach is expected to lead to greater cost savings and improve time management.

The multi-phase implementation of upgrades by multiple different vendors under the Modernization and Growth option will require significant testing to successfully integrate different solutions. This effort will contribute towards mitigating the timeline and budget risks associated with this option.

The Modernization and Growth option will require the utility to manage change management at the program level with each phase/project involving tailored training, staff communications, and other change management activities. Since many of these changes will reflect upgrades associated with existing system components, the costs of such change management activities will be modest.

In summary, the Modernization and Growth option is the most favourable option for both mitigating the strategic and tactical (project) risks outlined in previous sections of the Business Case document and supporting Toronto Hydro’s achievement of favourable outcomes for ratepayers in the short and long term.

Table 3: Breakdown of Estimated Program Costs

Program Phase	Description	Cost
Initiation and Discovery	• Prepare for execution and kick-off initiative(s) • Document and assess current state processes • Establish and gain approval on detailed requirements	$4.1 million*
Blueprinting	• Assess and confirm functional options and decide on solutions • Establish and gain approval on future state processes • Establish methods for confirming and monitoring benefits	$4.5 million*
Build & Implementation	• Develop/configure/formulate solutions • Conduct testing • Train stakeholders	$21.3 million*
Launch	• Establish means for operational support • Launch solution and deliver on post go-live launch strategy • Prepare for initiative closure and sustainment	$4.3 million*
Total		$ 34.2 million*

*All costs account for inflation

5 APPENDIX

This section provides a detailed description of the requirements by area:

<table>
<tr><th>ADMS Features and Components</th><th>Requirements</th></tr>
<tr><td>User Interface</td><td>

The users shall interact with the ADMS components via workstations installed at the Control Centre and various other locations.
The user interface (UI) shall allow authorized personnel to:

view measured and calculated real-time and near real-time, outage information (including vehicle and crew locations);
view Distributed Energy Resource (DER) information;
view historical outage and load data;
initiate control actions (with suitable security limits and controls); and,
interact with the ADMS applications.

UI includes Areas of Responsibility (AORs) that shall provide the means to route alarms, restrict supervisory control, restrict data entry, and enable data viewing to those personnel having the associated responsibility and authority.
As a minimum, the ADMS displays shall include:

Tabular displays
Trend lines
Displays containing bar charts, pie charts, and other mechanisms to view equipment status and trends
Single-line schematic diagrams showing the configuration, status, and loading of the distribution feeders, substations, and other power system facilities
Map-style displays showing properly scaled and geographically correct depictions of distribution lines overlaid on street maps. It shall also be possible to view dynamic data
Satellite style displays (e.g. Google Earth) containing similar information as map-style displays
Application function displays (alarm displays, video trend displays, and displays used to interface with the ADMS application functions)

</td></tr>
</table>

ADMS Features and Components	Requirements
	8. System management and diagnostic displays (security administration, system configuration, on-line/offline diagnostics, etc.) • Users shall be able to add operator notes containing free-form text associated with a specific device or ongoing outage. • On demand, the user shall create a simplified schematic display using the geographic information from GIS. • The User Interface security settings shall comply with Toronto Hydro security policies, standards and procedures. • This feature shall include Alarm Processing functions to alert system users to abnormal conditions on the power system. The Alarm Processing function shall also alert system users to ADMS and communication equipment failures and other abnormal ADMS conditions requiring attention.
DMS	• DMS includes a single Distribution System Operations Model (DSOM) that supports all distribution applications, including advanced distribution applications, outage management, and DERMS. • DMS includes load profiles for estimating the load for a given time/date for each different type of customer (residential, commercial, industrial, etc.). • DMS shall be a single centric process that supports model updates for all applications. • DMS shall enable a user to add, modify, or remove temporary elements to the Distribution Network Model through the operator user interface. • DSOM shall include Information for schematic displays of the electrical facilities, showing individual elements and interconnections, along with the operating state and other related information. It shall display current and nominal state. • The DSOM function shall include an Impedance Calculation application that shall calculate the impedance of overhead and underground line segments needed for the execution of other applications such as Unbalanced Load Flow and Fault Location.

ADMS Features and Components	Requirements
	• This component shall support a full-featured study mode environment that shall enable the user to execute any ADMS application (including DMS, OMS, and DERMS applications) to determine the impact of proposed operating actions and changes to the power system configuration in an "off-line" mode. • Network Topology Processor: shall use the DSOM connectivity model to determine the dynamic network connectivity and the energized, de-energized, looped, paralleled or grounded status of power system components, and DSOM shall visually represent these states. • DMS shall include suitable mechanisms for determining the real and reactive power on each distribution service transformer at any given time. • The component shall include facilities for determining the output of each distributed generating unit that is connected to the distribution system. • The Distribution Unbalanced Power Flow (UBLF) shall use the DSOM to calculate the electrical conditions (current, voltage, real and reactive power) for the entire distribution system. • This component shall include a Distribution State Estimation (DSE) application for calculating the distribution network state • This component shall include a short circuit analysis (SCA) application function that shall be able to compute short circuit currents for faults of all types. • The FLA function shall determine the approximate location of faults on distribution feeders. • FLISR shall be a model-driven solution that uses the as-operated distribution system model and topology processor, along with the status of circuit breakers, line reclosers and other feeder switches, fault detectors and faulted circuit indicators to determine an appropriate switching strategy to isolate the faulted feeder segment and restore service to as many healthy (un-faulted) sections as possible.

ADMS Features and Components	Requirements
	• Optimal Feeder Reconfiguration (OFR) function shall define optimal network configuration required for achieving one or more user-specified business objectives. • DMS shall include Volt-Amps-Reactive (VAR) Optimization functionality • DMS shall include load and generation forecasting (LGF) functions that are able to predict real and reactive load and generator output in the near future. • The Distribution Contingency Analysis (DCA) function shall identify and evaluate the impact of contingencies on the distribution network and recommend control actions capable of limiting their impact. • The ADMS Switch Order Management (SOM) function shall support the creation, execution, display, modification, maintenance, printing, and emailing (manual and automated) of switching orders containing a list of steps needed to support various work activities, and indicating executing field resources. • Customer Network Status Tracking System (CNSTS) Displays - The ADMS shall be able to generate tabular displays of customer/network connections to a user specified feeder, including associated (alternate) feeders in a dual radial/network feeder configuration. Toronto Hydro system operators will use the CNSTS display to perform feeder isolation. • The user shall be able to apply a tag to a single point, group of points, or all points in an RTU or in a substation (except for “limit override” and “normal state override” tags), to non-telemetered points, and to calculation points. When a tag has been applied to a point, a tag symbol separate from the quality code symbol shall be presented next to the tagged point on any display or report where the point is presented. • DMS shall include a Confined Space Hold Off function to prevent a feeder from being re-energized if there are any crews working in Confined Spaces on that feeder. • DMS shall record all of the information that is needed to precisely calculate the key reliability metrics that are tracked by Toronto

ADMS Features and Components	Requirements
	Hydro, to display these metrics in dashboard, and support data extraction into Business Intelligence (BI) for data analytics.
OMS	• The OMS function shall assist system operators in identifying customer outages, determining the approximate location of the outage, dispatching first responders, coordinating restoration activities, and confirming that power has been successfully restored to all affected customers. The OMS shall also assist in gathering data needed to compute outage statistics. • The OMS shall include a complete set of tabular, schematic, and geographical displays to allow authorized OMS users to view all outage related information and interact with the OMS applications. • The OMS display system shall include a set of application functions for locating user specified items that enables the user to rapidly navigate to specified locations such as a specific asset (e.g. a transformer, line switch, or fused cut out), a specific street address, or other location. • The OMS shall be able to acquire real-time inputs from field devices via Toronto Hydro's existing SCADA communications network, Inter-Control Centre Communication Protocol (ICCP) link to the Hydro One EMS, and other sources of near-real-time data used by Toronto Hydro. The OMS shall use this near-real-time information for detecting and predicting outages. • The OMS shall include a report writing package that is able to generate ad hoc and predetermined reports containing outage information and statistics for a user-defined time frame, specific equipment, customer, circuit, cause or system wide, for user defined time frames, specified areas, substations and feeders. • The OMS shall include several mechanisms for determining that an outage has occurred. As a minimum, these mechanisms shall include: 1. Telephone "lights out" calls from customers and other sources 2. Last gasp messages for Toronto Hydro's Advanced Metering Infrastructure (AMI) system 3. Operation of SCADA monitored/controlled circuit breakers, reclosers and other remote controlled and automated switchgear

ADMS Features and Components	Requirements
	4. Entries in Toronto Hydro's outage map website 5. Direct manual entries by the dispatcher 6. Toronto Hydro external website/app allowing customers to report outages 7. Customer outage calls reported from Interactive Voice Response System (IVR) • When outage information is received from more than one premises, the OMS shall group the calls, messages, and data that appear to be part of a single power system disturbance by applying user-specified rules. OMS should allow user to configure these grouping rules based on type of event (Real Outage versus Planned Switching) and time between events. • Once the trouble calls and AMI messages have been grouped, the OMS should use the "as operated" connectivity/topology model of the distribution feeder to trace upstream from the grouped outage call/message locations to the next fault interrupting device (fuse, recloser, circuit breaker) that is upstream from the customers who are experiencing an outage. • The OMS shall include a Damage Assessment function that Toronto Hydro will primarily use during major events (especially those requiring special incident response/storm centres) for managing a group of resources that are responsible for damage assessment. • The OMS shall have a function to automatically produce an Estimated Time of Restoration (ETOR) for each identified outage event. This function shall automatically calculate an ETOR for every outage that is predicted by the OMS. • The OMS should support receiving ETORs from mobile crews and dispatchers as well as automatic creation. • The OMS shall have a Crew Management module that enables the Trouble Dispatcher to manage crews, allocate/re-allocate resources, track contact information and their history of all previous calls and whether they were reached, whether they came in, or declined when called. This module should support different types of crews (e.g. System Response, Power Lineman, Metering, Forestry, Supervisors, etc.) • The OMS shall have a module for managing call backs to customers who have been restored following a power outage or interruption. This should

ADMS Features and Components	Requirements
	be done through callback, text or email update depending on customer preference. • During widespread outages that impact multiple locations, the OMS shall be able to sort and filter the outages to ensure that the most urgent incidents are addressed first. Prioritization of restoration activities shall be performed automatically by the OMS. • The OMS shall be able to manage "planned" outages that are scheduled in advance by Toronto Hydro to perform routine maintenance, repair work, new construction, and other activities. • The OMS shall track and record "momentary" interruptions that last less than a minute, which are often caused by the operation of circuit breakers, line reclosers, and distribution automation (DA) facilities • OMS shall support the future addition of a full-function Interactive Voice Response System (IVR). • The OMS shall be able to support Mobile Workforce Management (MWM) in order to reduce operation cost, enable more effective distribution system and asset management, and improve customer service by improving the management and dispatch of field personnel • The system shall provide mechanisms for managing incidents that do not result in outages but require controller attention and possible follow-up action, damage assessments including, foreign object on powerline, leaning pole, broken guy wire, etc.
SCADA	• SCADA shall be able to acquire real-time information from various sources, including: 1. Substation automation systems, RTUs, and Data Concentrators 2. Feeder devices that are equipped with SCADA communication facilities (remote controlled switches, line sensors, etc.) 3. Energy Centre (DERMS) via secure ICCP (two way) link 4. Hydro One Energy Management System via ICCP (two way) link 5. Oracle Network Management System (NMS) via ICCP (one way) link 6. Schneider ION PQ meters via cloud communications • The SCADA Administrator shall be able to put an RTU or individual points in the RTU in a test mode that will provide the capability to monitor,

ADMS Features and Components	Requirements
	transmit, and receive messages on a communication channel, RTU, and individual point basis. • All data acquired from the power system, all real time calculated values, and all manually entered data for non-telemetered points, as well as parameters to be output to field devices, and parameters that control the operation of real-time application programs shall be stored in a comprehensive system real-time database (RTDB). • The RTDB shall be the central interface between all elements of SCADA including the data acquisition software and the user interface software for real time information. • To facilitate flexible assignment of operational responsibilities to operators, the capability to associate the field devices with Areas of Responsibility (AOR) shall be provided. • The SCADA system will support multiple communication protocols and standards, and data acquisition techniques. • Data retrieved from RTUs shall be immediately checked for certain basic error conditions including incorrect response, data buffer overwrite error, and invalid message security codes. All detected errors shall be recorded for maintenance purposes. • Data acquired from RTUs as well as data received from other data sources (e.g. ICCP data) shall be processed and placed in the RTDB as soon as it is received. • Status data shall be processed for every scan period when such data is received to determine if changes have taken place. • The Operations Monitoring function of SCADA shall track the number of operations made by every breaker, capacitor switch, recloser, and load break switch that is monitored by the ADMS. • SCADA shall include analog and status “pseudo” points whose value or state is manually inserted or calculated by performing arithmetical and/or logical operations on the values or states of other system input variables and other pseudo points. • SCADA shall include "pulse accumulator" points representing the number of times an associated piece of power equipment has changed state. • Any data received from other systems through ICCP links and secure ICCP links shall be processed using the same data processing methods

ADMS Features and Components	Requirements
	as telemetered points. Data items shall be checked for reasonability as soon as it is received. • SCADA shall control power system apparatus located at distribution substations and field locations (out on distribution feeders). This component shall support the following types of control actions: 1. Digital outputs: on/off control commands that activate control output contacts 2. Analog outputs: control commands that activate a voltage or current signal whose magnitude varies with the desired level of control 3. Setpoint control: change the settings in an intelligent controller associated with the device being controlled • Tags: It shall be possible to assign any of the following supervisory control inhibit properties to each tag type: 1. All controls allowed 2. Control inhibited in one direction, such as “Close” function 3. Control inhibited in the other direction, such as “Trip” function 4. All controls inhibited • Control Command Validations: The request shall be rejected by the system if: 1. The device is not subject to supervisory control of the type being attempted. 2. The requested control operation is inhibited by a tag placed on the device. 3. An Uninitialized, Failed, Deactivated, or Manually Entered data quality indicator is shown for the device. 4. The user’s AOR does not permit this action. 5. The Operating Mode of the workstation attempting control does not permit supervisory control. 6. A control request for the same device from another workstation is still pending (i.e. the request is not yet executed or the commanded control is not yet completed).

<table>
<tr><th>ADMS Features and Components</th><th>Requirements</th></tr>
<tr><td></td><td>7. A control request for a device is in a direction that is not allowed (i.e. single sided control where the device is defined to only be controlled in one direction).
• The system shall include the capability to define pre-operational checks
• SCADA shall be able to exchange real-time data with other systems. The communication for these data exchanges shall be International Electrical Commission (IEC) 60870-6 TASE.2, and shall be in compliance with the ICCP security requirements in IEC 62351-3 and IEC 62351-4 for those external systems that also support secure ICCP.</td></tr>
<tr><td>DERMS</td><td>• DERMS shall be able to monitor and control customer-owned and Toronto Hydro-owned DERs that are connected to the electric distribution portion of the electric grid. DERs managed by DERMS shall include distributed generators (cogeneration, combined heating and power, microturbines, etc.), intermittent renewable generators (solar photovoltaic (PV), wind, etc.), energy storage, controllable loads (demand response), and electric vehicles (EVs).
• DERMS shall include secure and convenient mechanisms for viewing real time, historical, and forecasted information, alarms and events, reports and logs, and other information about the DERs and for interacting with the DERMS application functions.
• DERMS shall support a variety of techniques for controlling DERs including, but not limited to:
  ◦ Direct control of active and reactive power at the DER point of common coupling
  ◦ Set a voltage reference value, power angle, and schedule for operational VAR limits/settings
  ◦ Modify maximum volt-amp limits/ settings
  ◦ Switch DERs from autonomous control to remote control
  ◦ Establish a fixed schedule for operating the DER
• All DER control actions shall be accomplished through SCADA using RTUs installed at each DER location
• DERMS shall enable system operators to initiate changes in the DER output level.</td></tr>
</table>

ADMS Features and Components	Requirements
	• It shall be possible to analyze DER operations and impacts of distribution system operation in "study mode" which allows the user to switch DERs on and off, change the output level, and perform other possible changes without impacting the real time (Live) operation of the electric distribution system. • [redacted] • Modeling: DERMS shall maintain awareness of DER ratings and limitations and shall be able to enforce operating requirements from technical studies which are written into the contract. As a minimum, DERMS shall be able to enforce limits on operating power factor, voltage, frequency, ramp rates, charging and discharging limits (storage only), and power quality requirements. If ratings are violated, DERMS shall generate an alarm to alert the operator of this condition.

ADMS Features and Components	Requirements
	• DERMS shall include facilities for storing (archiving) and later retrieving historical DER operational data. • Forecasting: DERMS should be able to supply DER Generation forecasts for various time intervals, including short term (next hour), middle term (next few days), and long term (next week or longer). • DERMS shall be able to monitor and control customer-owned and Toronto Hydro owned microgrids comprised of a set of interconnected DERs in a well-defined portion of the electric distribution system. DERMS shall be able to initiate "planned" transitions of the microgrid from grid-connected to islanded mode of operation. • DERMS shall provide mechanisms for registering customer-owned and Toronto Hydro owned DERs so that these DERs can be monitored and in some cases controlled by DERMS. DERMS shall also facilitate incentive payments for verified services provided at Toronto Hydro's request during system events (e.g. emergency load shedding). • DERMS system should support transactive energy concepts as well as the economic and control techniques used to manage the flow or exchange of energy within an existing electric power system in regards to economic and market based standard values of energy.
Training Simulator	• The Dispatcher Training Simulator (DTS) shall include playback mode and interactive (simulator) mode. Playback mode shall enable the user to examine previously-recorded data in view-only mode. Interactive mode shall enable the user to view information computed by the simulator in response to a simulated event (e.g. a fault), enter simulated control commands, and view the simulated power system response to these commands. • When operating in playback mode or interactive simulator mode, it shall be possible to simulate all types of data items that are available in the ADMS, including time series SCADA inputs and calculated data items, customer outage calls, AMI last gasp messages, available crews and crew locations, and DER operation (distributed generators, energy storage, and controllable loads (Demand response)). • The DTS shall enable the user to view dynamically updating information on any ADMS display that contains the information in question, such as

ADMS Features and Components	Requirements
	tabular displays, graphical displays, trend lines, satellite (Google Earth) displays, and any other available ADMS display format. • The DTS shall allow Toronto Hydro to simulate the operation of all SCADA, OMS, DMS, and DERMS application functions and displays in interactive simulator mode. • The DTS shall support multiple simultaneous trainers and trainees. • The DTS interactive simulator mode shall use a power system model to determine how the actual power system would react to random trainer-initiated events. • The System's trainer module shall contain trainee evaluation tools to facilitate assessment of the trainee’s performance. These tools shall monitor the ability of the trainee to respond to events such as overload violations and outages. At the end of each session, the system shall provide trainers with customizable reports on trainee performance.

Preliminary Scoping Business Case:

SAP ERP Upgrade

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1 Executive Summary

Project Name	Capital Expenditure
SAP ERP Upgrade	$ 28 million

Toronto Hydro uses SAP's Enterprise Resource Planning (ERP) system. The ERP system supports a number of cross-functional critical organizational processes such as customer connections, event management, and meter to cash. The SAP system is highly integrated with a number of core information technology (IT) systems that support key organizational processes such as health and safety, and asset management. The ERP is a critical Tier 1 application as operations across a number of different business units significantly depend on the ERP system's workflows, data, and reports.

The current version of the SAP ERP system will reach end of life by 2027. A system that is within the vendor support lifecycle receives the latest security patches and service packs. This helps protect the system from existing and emerging cyber security threats and keeps the system compatible with the underlying infrastructure, ensuring reliable performance and robust system availability. Thus, maintaining vendor support ensures the timely resolution of system incidents and minimizes the risk of system downtime, which allows business operations to proceed uninterrupted and maintains productivity.

In order to maintain these benefits and avoid reliability and cyber security risks, Toronto Hydro plans to upgrade its ERP system within the 2025-2029 rate period to a newer version that will retain current vendor support. A well-supported ERP system also aligns with the utility's strategic objectives as continuing vendor support enables the enhancement and adaptation of the system and the modernization of business processes in accordance with customers' evolving needs and broader industry trends such as electrification.

Given the criticality of the ERP system to Toronto Hydro's day-to-day operations, the maintenance of system reliability, and business continuity, the SAP ERP upgrade is necessary to support current and future business processes in an efficient and effective manner. To ensure an effective solution, the utility assessed four options as follows:

1. Managed Deterioration: Maintain status quo with the current SAP Enterprise Central Component (ECC) version;
2. System Sustainment: Execute required reactive work to keep the SAP ECC current without undertaking an upgrade;
3. S/4 HANA Private Cloud (On-Prem): Upgrade to S/4 HANA, the next supported SAP ERP version and implement on-premises (i.e. on-prem) on private cloud; or
4. S/4 HANA Public Cloud: Adopt SAP's ERP solution on public cloud.

Toronto Hydro evaluated each option against three broad categories:

A) **Project Approach** – This category considered criteria such as expected project complexity, project costs, project timeline, and change impacts to the organization.

B) **Innovation** – This category evaluated each option in terms of contribution to productivity and efficiency, as well as alignment with Toronto Hydro's strategic objectives and outcomes.

C) **Maintenance** – This category evaluated the options from an operational perspective with respect to expected ongoing vendor sustainment costs, cyber security risks, and overall system reliability.

Toronto Hydro concluded through its options analysis that S/4 HANA Private Cloud (On-Prem) is the preferred option because of the stability it provides from a system reliability and maintenance perspective, and the potential flexibility it provides to help the utility improve efficiency and modernize its business processes in accordance with it's strategic objectives and outcomes. Under this option, Toronto Hydro will receive full vendor support until 2040. Although this option entails some project-related risks in the short term, the utility expects to mitigate these risks through appropriate planning and strong project governance.

Overall, the SAP ERP Upgrade project will:

- Reduce business continuity risks that may arise from system and infrastructure failures relating to the ERP system;
- Contribute to maintaining a robust cyber security posture;
- Build a foundation to support future process automation opportunities and associated productivity gains; and,
- Provide Toronto Hydro with greater flexibility to innovate and modernize its business processes in alignment with its strategic objectives and outcomes.

2 Problem / Opportunity Statement

2.1 Background

Toronto Hydro implemented the SAP ERP system on October 1, 2018. The SAP ERP system is a core Tier 1 IT system as it supports over 150 business processes in Toronto Hydro and impacts a large number of the utility's business units.

2.1.1 Application Components

Toronto Hydro's SAP ERP system is currently comprised of both cloud and on-premises modules.

The cloud modules include:

- SAP SuccessFactors: A solution that supports human resources (HR) processes such as recruiting, onboarding and offboarding, training, and performance management.
- SAP Ariba: A strategic sourcing suite that serves a variety of procurement functions such as sourcing (e.g. RFx)[1], contracting, and vendor spend analysis.
- SAP Concur: An expense management system to manage travel and business expenses.

The cloud modules are integrated with the on-premises modules and follow a subscription licensing model. SAP maintains and updates these systems as part of system lifecycle management. The SAP ERP system upgrade does not include upgrades to cloud modules.

The on-premises module, called Enterprise Central Component (ECC), includes the following components:

- Enterprise Asset Management (EAM): used for managing the financial lifecycle of the utility's assets.
- Record to Report (R2R): used to collect, process, and present financial data.
- Source to Procurement (S2P): enables integrated procurement processes such as purchase requisitions or purchase orders in SAP.
- Human Capital Management (HCM): integrates HR processes relating to payroll, time sheeting, and attendance, with financial systems.
- Warehouse Management System (WMS): enables warehouse management processes and integrates with procurement and financial processes.

[1] RFx is defined as request for any type of proposal including Request for Information (RFI), Request for Quotation (RFQ), Request for Proposal (RFP) and Request for Information (RFI) proposal.

These components follow the conventional perpetual licensing, support and maintenance model. The SAP ERP system upgrade will focus primarily on upgrading the on-premises module (i.e. ECC).

2.1.2 Application Integration

In addition to integrating with the previously discussed cloud modules, the on-premises SAP modules also integrate with many Tier 1 and Tier 2 IT systems. These business systems and their supported functions include:

Systems	Supported Business Functions
Asset Investment Planning	Distribution asset management processes
Emergency Callout System	Automated callout system used in disaster and emergency conditions
Customer Information System	Linking customer billing and accounts receivable processes to financial systems
Employee Health Benefits	Employee benefits management
Enterprise Data Warehouse	Reporting and analytics across various enterprise systems
Electronic Tailboard System	Tool for on-site safety risk assessments by field crews
Financial Institution of Record	Payroll processing, accounts payable and accounts receivable processes
Financial Reporting System	External reporting processes for financial disclosures
Vehicle GPS System	Fleet vehicles management
Labour Relations System	Business processes for employee and labour relations
Network Management System	Real-time network modelling used in distribution system operations
ERP Data Warehouse	ERP Reporting for SAP
Vendor Invoice Management System	Accounts payable processes

2.1.3 Infrastructure Components

The on-premises SAP modules are supported by a technology stack hosted in Toronto Hydro's Enterprise Data Centre. This infrastructure is comprised of the following:

- Server Infrastructure: The server infrastructure consists of both physical server hardware and virtual servers. This infrastructure relies on IBM infrastructure.

- Database Infrastructure: The database infrastructure supports the structured and unstructured data in the ERP System. The infrastructure is supported by an Oracle database farm.
- Middleware Infrastructure: The middleware infrastructure enables the integration between systems, and supports the movement of data. The two primary middleware components are the Websphere Application Integration Platform (AIP) and SAP Data Services.

2.2 Problem Statement

As previously discussed, the secure and reliable operation of the SAP ERP system is critical to Toronto Hydro's operations. Although the SAP ERP system is currently fully supported, SAP plans to terminate vendor support by 2027. Therefore, Toronto Hydro needs to maintain and upgrade the SAP ERP system and the underlying infrastructure to retain vendor support and continue receiving periodic service packs, patches, cyber security fixes, and technical support for product releases, incidents, or service requests. Current and active vendor support would ensure appropriate housekeeping and enable incremental maintenance and enhancements of the system. The following section discusses the risks that the utility may incur in the event that vendor support is lost and the condition of the SAP ERP system deteriorates without further upgrades.

2.2.1 System Risks: Infrastructure Lifecycle

While the current SAP ERP infrastructure is fully supported, the end of life for the current application servers and database servers is forecasted to be in the 2026–2027 timeframe. Beyond the SAP ERP system's end of life, Toronto Hydro would need to plan for contingencies that include sourcing hardware components from third party vendors. In extreme cases (e.g. system interruptions), the resolution of infrastructure issues might require applying solutions on a trial and error basis, greatly reducing the reliability of the solution and possibly prolonging system restoration times. In any case, without infrastructure upgrades significant risks of delayed recovery from system failure would arise and adversely impact business operations.

2.2.2 System Risks: Cyber Security

The SAP ERP system receives periodic service packs and patches from SAP. Occasionally, SAP also releases ad hoc security patches to address known critical security vulnerabilities. However, without vendor support, Toronto Hydro would lose access to these service packs and patches, which would increase the ERP system's exposure to cyber security threats and increase the risk to the utility.

2.2.3 Business Continuity Risks

Without upgrades and vendor support, when the SAP ERP system is past its end of life, Toronto Hydro may not be able to resolve system defects and incidents in a timely manner. As a result, business processes and functions would be adversely impacted resulting in a decrease in productivity and a reduction to the overall reliability of the system.

To address these challenges, the utility might have to implement manual workarounds, which may introduce significant operational inefficiencies resulting in lower service levels (i.e. longer processing times). In addition, the technical availability of vendor products or support (e.g. the compatibility of certain patches and security updates) in the future may be contingent upon Toronto Hydro upgrading its ERP system. In other words, if the utility were to defer system upgrades to the point where the existing systems and infrastructure are no longer compatible with new patches or products, it would need to find alternative mechanisms to execute its business processes until it upgrades its ERP system to the latest version. This exposes a number of critical business processes to operational inefficiencies, risk of failure, and could hinder day-to-day operations.

2.2.4 Process Automation and Innovation

In order to effectively respond to the evolution of customers' needs and expectations arising from emerging industry trends such as electrification and decarbonization, Toronto Hydro will need to invest in modernizing its business processes through process automation, innovation, and the adoption of industry best practices. An upgraded SAP ERP system will allow Toronto Hydro to adopt new business processes and streamline existing business processes with greater flexibility and speed.

At this point in the product lifecycle, SAP no longer provides any new functional enhancements to the ECC product functionality. If Toronto Hydro were to forego upgrades to a newer solution, it would be hampered from efficiently achieving the above goals, as it would no longer receive functional enhancements, improvements, and efficiency gains from the vendor. As a result, the utility may be severely constrained in customizing the current SAP ERP system, limiting Toronto Hydro's ability to flexibly adapt its business processes to the evolution of customers' needs and expectations as well as other industry trends.

3 Business Requirements Summary

The SAP ERP Upgrade is a transformational project that impacts various business processes across Toronto Hydro. This section provides a high-level summary of the functional (i.e. related to maintaining current system functionality) and technical (i.e. related to conformance with the utility's IT standards) requirements for the upgrade. A more detailed list of can be found in the Appendix to this Business Case.

3.1 Functional Requirements

Categories	Functional Requirement
Asset Plan Build Maintain Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Track, manage, and report the asset lifecycle - Include details for each phase of the asset lifecycle (e.g. cost elements, approvals, work assignments, projects, and maintenance associated with an asset) with consideration for data and workflows - Require data consistency across multiple divisions and understanding of detailed business processes to enable future cross-functional innovation opportunities
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Serve customers' specific grid connection needs - Include the end to end workflow, data, and financial aspects across all connection process stages from design to construction and ultimately energization - Ensure effective communication with customers and facilitate financial transactions to better serve customers, and create opportunities for process improvement and efficiencies - Evaluate project estimates at a granular level, calculate accruals and net present value (NPV), and retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Govern the interactions between field work and Control Centre processes from planning to execution including the procedural aspects as well as the underlying components - Ensures business process consistency as noted with the current SAP ERP system, including the different elements supporting field work, such as planning, costing, and engaging operationally with customers. - Support an efficient and effective event management process to serve customers

Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer timekeeping and payroll processes - Ensure time entries and approvals are appropriately recorded and payroll is appropriately disbursed. - Maintain timekeeping processes and provide opportunities for continuous improvement. - Calculate different payroll components and produce the necessary payroll related artifacts and compliance reporting - House a number of workflows and complex rules to support time submissions that comply with collective agreements and legislative requirements - Prescribe the details for workflows, data, business and legislative rules, and reporting to support and govern these processes
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer accounts receivable and payment receipts from customers - Administer rules for monthly interest, late payment charges, deposits, and record the correct transactions to Toronto Hydro's General Ledger (GL) - Elicit details of different workflows, data elements, approvals, and user roles to fulfill the Meter to Cash process - Support industry best practices associated with relevant document lifecycles and their management in the Meter to Cash process, including items such as job quotations, billing, etc. - Consistently execute the process in an efficient and effective manner by calculating the monthly interest due to customers for deposits and process bills for or refunds to customers for capital contributions and expansion deposits
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Support key financial backend activities - Apply rules to support asset level transactions from the balance sheet perspective - Ensure asset costs are appropriately captured across the asset lifecycle - Enable accurate and detailed financial reporting through detailed workflows - Specify the necessary elements to capture financial transactions, apply stringent controls, consolidate the transactions across the organization, and accurately report them in accordance with applicable accounting, regulatory and financial guidelines

	- Accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger - Enhance end user experience - Ensure compliance with accounting, financial, and regulatory guidelines
Source to Pay Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Provide the framework for procurement activities like sourcing, contracts, inventory management and vendor management - Build on procurement policies and procedures and include the entire contract lifecycle - Configure spend approval workflows to efficiently manage the procurement process - Functional requirements will specify the details for these components to ensure the process in the system is comprehensive and runs effectively - Allow the system to meet procurement and payment guidelines, govern the procurement process and track vendor performance - Optimize the procurement process by increasing process efficiencies
Other Requirements Pillar: Innovation Topic(s): User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Allow all attributes associated with the following data be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, Work Breakdown Structure (WBS) and Internal Order (IO) data, material and vendor master data, purchase order, contract and project data - Allow users to book a vehicle and capture necessary user information. Present the user with vehicle attributes and apply business rules at the time of the booking - Continue to integrate with other core Toronto Hydro systems to ensure ongoing uninterrupted service

3.2 Technical Requirements

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	- System infrastructure must adhere to Toronto Hydro's IT standards, including alignment with industry norms for optimal system performance and operations - Ensure the time between system loss and system recovery is minimized, and system downtime is reduced, ensuring business continuity
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	- Adhere to Toronto Hydro's IT standards, including alignment with best practices related to user access to the system, data encryption within SAP, and appropriate security practices integrated with other systems - Allows users to view data corresponding to their respective roles and to execute their core functions

3.3 Assumptions & Dependencies

Toronto Hydro makes the following assumptions relating to the overall scope of this project:

- The SAP ECC lifecycle will not change.
- Toronto Hydro will not implement any new SAP modules within the current SAP ECC.
- The cloud modules SAP Ariba, SAP SuccessFactors, and SAP Concur will persist until the SAP ERP Upgrade concludes.
- Existing integrations to the SAP ECC will remain intact until the SAP ERP Upgrade concludes.
- No new and major technological developments that impact SAP ECC and its underlying infrastructure will emerge.
- SAP's S/4 HANA product, services and licensing will not deviate from the current state.
- There will be no new and major changes to functional and/or technical requirements.

- There will be no change in organizational direction relating to the overall project approach described in this Business Case document.

Any change in the assumptions listed above, will require a reassessment of the project scope, timelines, and costs.

4 Options Analysis and Recommendation

Toronto Hydro evaluated a number of options to address the risks and challenges discussed above in Section Two and engaged various internal and external stakeholders to determine the optimal solution.

As a starting point, Toronto Hydro reviewed the current state functional and technical requirements that the SAP ERP system fulfills and the system's footprint against the utility's Information Technology Investment Strategy.[2]

Toronto Hydro also considered available options in terms of their alignment with the utility's strategic objectives and outcomes for the 2025-2029 rate period, and specifically whether individual options would provide sufficient flexibility in modernizing business processes by enabling enhancements to the SAP ERP system.

This exercise helped Toronto Hydro identify and assess the four options that are discussed in greater detail below.

4.1 Options Analysis

Option 1 - Managed Deterioration

Under this option, Toronto Hydro would not upgrade the SAP ERP system's current infrastructure and applications. Due to the several drawbacks discussed below, the utility has not selected this option.

Maintaining current assets in operational condition under this option would require Toronto Hydro to purchase extended support for the infrastructure and the application at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potentially could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would also significantly increase cyber security risks. As an application ages, the code and communication standards used by it become outdated, making the application more vulnerable to cyber security threats. Toronto Hydro would be severely constrained in its ability to

[2] Exhibit 2B, Seciton D8 – Information Technology (IT) Investment Strategy

mitigate this risk, and any efforts to mitigate this risk may compromise other functions. For example, the utility may be unable to modify the SAP ERP system to the extent that any customizations would adversely impact system performance and efficiency. Alternatively, if customizations by the utility are not supported by SAP, Toronto Hydro would run the risk of voiding its support contract with SAP, leaving the aging system even more vulnerable to cyber security threats without comprehensive vendor support.

Furthermore, finding the technical resources to support legacy applications is challenging. As the resources that are qualified to support SAP are currently focusing on updating their skillsets for S/4 HANA, the industry pool of resources available to Toronto Hydro to implement this option would significantly shrink in the near future and as a result, the utility may not be able to address this gap.

Finally, this option would not allow Toronto Hydro to enhance its business processes through automation and innovation, and by extension, respond effectively to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization. Continuing to work with the legacy version of the SAP ERP system would prevent the utility from accessing new enhancements and technological developments, and thus severely curtail its ability and flexibility in modernizing its services or underlying business processes. Therefore, this option does not align with Toronto Hydro's strategic objectives and outcomes.

Option 2 - System Sustainment

Under this option, Toronto Hydro would implement only the minimally necessary upgrades to the SAP ERP system's underlying infrastructure components in the 2025 – 2029 rate period. The application would not receive any upgrades or any new features or functionality beyond 2027 (i.e. the end of vendor support). Although the risk profile of this option would be somewhat more moderate compared to Option 1, it would also represent significant lost opportunities for Toronto Hydro, as the utility would not be able to leverage new enhancements and technological developments from more comprehensive system upgrades to modernize its services and underlying business processes in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Similar to Option 1, maintaining current assets in operational condition under this option would require the utility to purchase extended support at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and furthermore, vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and/or its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potential could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would mitigate cyber security risks to a limited extent. Under the extended support, the applications and underlying infrastructure would continue receiving vendor security patches; however, there would be no guarantee that these security patches could fully mitigate all types of cyber security threats encountered today and in the future.

It is highly likely that Toronto Hydro will need to upgrade the SAP ERP system's underlying infrastructure in the 2025 – 2029 time period. However, it is possible that the renewed infrastructure might not be fully compatible with the current SAP ECC version, which would require the utility to rely on manual workarounds to ensure the continuity of business processes, consequently decreasing the efficiency of such processes. In any case, Toronto Hydro likely would have to invest in upgrading to the latest version of the SAP product and migrating the HANA database at some point, as the benefits of the new infrastructure would not be fully realized until Toronto Hydro migrates to the new SAP system. Because this option would not fully address the previously discussed issues and drive further investments in the future, it ranks poorly in terms of cost effectiveness.

Although this option would allow Toronto Hydro to modernize its business processes through automation and innovation to a limited extent, the value received from related investments likely would not be optimized, as the utility would have to make further upgrades in the near term, before the end of life of the newly implemented assets. In addition, this option may require Toronto Hydro to procure and operate a number of outdated peripheral systems to continue to innovate.

Option 3 - S/4 HANA Private Cloud (On-Prem) – Recommended Option:

Under this option, Toronto Hydro would implement the S/4 HANA (On-Prem) solution, which is the latest available version of the SAP ERP system. It would embed the latest software, code, security, and communication standards, which would also align with the utility's IT standards. This option will mitigate cybersecurity risks for both, the applications and underlying infrastructure by ensuring a robust cybersecurity posture through continued access to vendor security patches.

To implement this option, Toronto Hydro would purchase private cloud licenses to install the application on its infrastructure in its on-premises Enterprise Data Centre. The application would be configured to enable existing business processes in the system. This may require incremental changes to some existing business processes which would result in some change management risk. This option would allow the utility to flexibly control the maintenance windows for the SAP application and infrastructure based on organizational needs. Furthermore, Toronto Hydro would be able to evaluate new product releases based on new functionalities, validate them against existing and future business needs, and determine the appropriate time to implement the new functionality.

By upgrading to the latest version of the SAP solution, Toronto Hydro would have access to a large resource pool of technical and functional resources whose skillsets would evolve to include HANA in the next few years. This would ensure that the utility is able to operate and maintain its ERP system in a much more cost-effective way and without having to depend on technical resources to support and sustain a legacy system.

SAP will fully support the S/4 HANA application until 2040. The SAP ERP Upgrade will mitigate business continuity risks by ensuring high system availability and full vendor support to resolve any issues in a timely and effective manner. Toronto Hydro would also have the option to implement periodic enhancement packs based on the desired benefits. This flexibility would support the utility's modernization of business processes through automation, innovation, and integration with other applications and systems. Thus, Toronto Hydro could adapt its services and underlying business processes much more easily and at an optimal cost in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Option 4 –S/4 HANA Public Cloud

Under this option, Toronto Hydro would implement SAP's S/4 HANA public cloud solution, which is a software-as-a service (SaaS) application. Although this solution would also have the latest features and releases, the utility anticipates that the available configurations would not align with its business practices. As such, Toronto Hydro would need to adapt its existing business processes to work in tandem with the functionality of the S/4 HANA public cloud application, which may result in inefficiencies and generate additional change management costs. For example, the utility might need to update its job quotation templates to adhere to the standard formatting used in the S/4 HANA public cloud.

This option would pose significant change management risks, as the vendor might release new features and functionalities to users with limited or no ability to modify them to meet business requirements. Thus, redesigning business processes to conform to the evolution of the ERP system would require considerable efforts and time to implement, plan, and manage changes, and retrain employees accordingly.

Under this option, Toronto Hydro would have very limited direct control of the application and some application components would not be configurable or customizable. For example, the utility uses SAP for timekeeping and the current solution caters to different employee types and their associated rules and workflows. By contrast, the public cloud option might not be able to fulfill all functional and business requirements. Consequently, Toronto Hydro may need to resort to a number of manual procedures to fully meet such requirements. Effectively, the utility would be dependent on its vendor(s), namely the cloud infrastructure provider and the application host, who would determine at their sole discretion release schedules and service elements. In order to meet the vendor timelines and release schedules, Toronto Hydro might need to reallocate resources from other areas to ensure that testing is completed on time. This lack of control over downtime hours and maintenance windows could present a major risk to the utility's ability to restore outages and respond to major events in a timely and effective manner. Therefore, this option would introduce significant operational and business continuity risks.

SAP will fully support the S/4 HANA application until 2040. Toronto Hydro would have the option to implement periodically released enhancement packs based on the desired benefits. Access to such enhancements would support the utility's modernization of business processes through automation and innovation to a limited extent. However, these benefits would be likely offset by the need to deploy extensive resources to ensure integration with other applications and systems and redesign business processes to conform to the vendor-led evolution of the ERP system.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following criteria:

A) The **Project Approach** category includes the different factors in executing a project such as:

- Project complexity (e.g. challenges in project design and technical details, end user impact and associated risk);
- Project costs (e.g. planning, design, implementation costs);
- Project timelines (project task start and end dates); and,
- Change Management (implementation of a single new technology, or an overall digital transformation overhaul, adapting to market changes, launching new products)

B) The **Innovation** category considers how the ERP technology fosters business process improvements, increases the velocity of business processes, enables future organizational transformation, and provides more meaningful information to the end user for sound business decisions. It ensures the project's alignment of:

- SAP technology landscape against Toronto Hydro's IT standards; and,
- Toronto Hydro's strategic objectives and outcomes, overall industry trends, and future improvement opportunities, in accordance with the IT Investment Strategy.

C) The **Maintenance** category evaluates day to day operations from the perspective of ongoing system operability, including the ability to respond to system issues and incidents, and the sustainability of business operations. The relevant factors under this category are:

- Cyber Security – which includes protection from cyber threats against the integrity and operation of the distribution system and the confidentiality of customers' and employees' personal information;

- Flexibility in System Maintenance Windows - to ensure business continuity under all operating scenarios, including critical storm events and high volume outage events; and,
- Toronto Hydro's control of the end-use product to ensure minimal disruption from system changes.

High Level Options Comparison

A high-level comparison of the options is provided in the table below.

Table 1: Options Comparison

Options	Project Approach				Innovation			Maintenance			
	Project Complexity	Project Costs	Project Timeline	TH Change Management	Enablement	Alignment with TH IT Standards	User Experience	Vendor Support	Cyber Security Risks	IT Reliability	Control of Product Feature TH Releases
1. Managed Deterioration											
2. System Sustainment											
3. S/4 HANA Private Cloud (On-Premise)											
4. S/4 HANA Public Cloud											

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

Comparing all of the options presented in the preceding sections, Toronto Hydro recommends Option 3, the S/4HANA Private Cloud (On-Prem) solution for the 2025–2029 rate period as it poses the least amount of overall risk and provides the greatest benefits across all three categories of project approach, innovation, and maintenance. Specifically, the benefits of the S/4 Hana Private Cloud (On-Prem) solution include a customized system that provides enhanced capabilities to process data and execute business functions, and ongoing vendor support.

Although there are increased project risks associated with implementing a new system, these risks can be mitigated though a robust project governance structure.

With respect to the project approach criteria, the Managed Deterioration and System Sustainment options rank the highest. Both options maintain the status quo to differing degrees and involve a limited level of investment in new products or initiatives, and thus have little to no impact on the end-user experience. As a result, both options result in a relatively low risk with respect to the overall project scope, timelines, and costs. However, in the long-term, both options would require Toronto Hydro to upgrade its SAP ERP system beyond 2030, therefore introducing inherent maintenance risks that are further elaborated on below. The S/4 HANA Public Cloud option ranks the lowest with respect to project approach criteria. This option provides little to no customization alternatives to the utility, and requires the project to expend resources to conform Toronto Hydro's current processes and functional requirements to the vendor-supplied solution. As such, there is a high risk that the project outcome could result in process inefficiencies in business operations, increase the costs of executing business processes, and limit the development of a more effective system. With respect to project approach criteria, the S/4 HANA Private Cloud (On-Prem) option ranks higher than the S/4 Public Cloud option. This option has higher costs than the Managed Deterioration and System Sustainment options as a full system upgrade is required, and this includes re-establishing existing business processes on the new ERP system. However, this option leads to lower overall risk through greater control over configuration and customizations, and limited impacts to existing business processes thereby reducing the organizational and change management risk. While there are some increased project complexity risks due to implementation of these new functionalities, these risks can be mitigated through a robust project governance structure.

With respect to the innovation criteria, the S/4 HANA Private Cloud (On-Prem) option would rank the highest as it would enable the utility to establish a modern platform with enhanced capabilities to process data and efficiently execute business processes. This option would take full advantage of product enhancements and new technologies, and would enable further modernization and business transformation. By contrast, the Managed Deterioration and System Sustainment options rank the lowest as both options would retain the current SAP ERP version. As a result, they would provide fewer opportunities for Toronto Hydro to improve business processes, enable future business transformation, and enhance the end-user experience. Both options would involve retaining outdated back-end infrastructure that would be unable to support new data processing capabilities and would result in the deterioration of the end-user experience. While the S/4 HANA Public Cloud option would rank higher than the Managed Deterioration and System Sustainment options with respect to innovation, this option would only allow for modernization within the confines of the vendor-supplied solution. Therefore, it would pose a risk of misalignment between Toronto Hydro's strategic objectives and the vendor's product roadmap. This would impact the effectiveness and pace of the utility's ability to implement system changes and modernize its business processes in response to future industry challenges.

Lastly, under the Maintenance criteria, S/4 HANA Private Cloud (On-Prem) option ranks the highest, as it ensures ongoing vendor support, greater control over feature releases and the timing of those feature releases. The Managed Deterioration and System Sustainment options would rank the lowest. Both options would retain the current infrastructure, which would likely limit vendor support to a best effort basis and would not benefit from security updates to mitigate cyber threats to the SAP ERP system. S/4 HANA Public Cloud ranks higher than the Managed Deterioration and System Sustainment options with respect to Maintenance criteria. Under this option, the utility's dependence on its vendor(s) would give rise to several risks related to business continuity (e.g. in securing support from vendor resources in a timely fashion during emergencies) and risks with respect to the timing and flexibility of product releases if the utility were to require a rescheduling to account for unforeseen circumstances.

4.4 Estimated Project Timelines and Costs

Estimated Project Delivery Duration: 24 months

Estimated Capital Expenditure Breakdown:

Group	Description	Costs ($M)
Internal labor (IT and business resources, stream leads, etc.)	Toronto Hydro full-time employees assigned to the project from initiation, blueprinting, build and launch to closure	$ 4.7
Contractors	Third party specialist resources onboarded with specific S/4 HANA project skillsets to augment the Toronto Hydro team	$ 3.8
Licences	IT software costs for using the new S/4 HANA Private Cloud (On-Premises) ERP system	$ 4.5
Hardware	IT infrastructure to support the new and upgraded S/4 HANA ERP system IT infrastructure to execute the backend system processes as per specifications	$ 3.0
Vendors (S/4 Upgrade System Integrator, other specialized vendors)	Vendor identified to implement the project from initiation, blueprinting, build and launch to closure	$ 12.0
Total		**$ 28.0**

Estimated Project Operational Expenditure:

Group	Description	Costs ($M)
Data Migration	Migrate data from the current SAP ECC system Complete necessary data migration checks Ensure continuity in business processes	$ 0.5
Training and Change Management	Train employees in the new S/4 HANA system Engage and educate employees of system changes and business process changes	$ 0.5
Post Go-Live Support	Hand-off technical and functional aspects of the project to the appropriate Toronto Hydro resources Ensure business processes are functioning as expected and address any user queries	$ 0.6
Total		**$ 1.6**

5 Appendix

The SAP ERP Upgrade is a transformational project and impacts a large number of Toronto Hydro's business units. The requirements presented in this Business Case consider the following:

- Functional Requirements: Maintain current system functionality to support business processes
- Technical Requirements: Consider new technology trends consistent with Toronto Hydro standards

5.1 Functional Requirements

<table>
<tr><th>Categories</th><th>Functional Requirement</th></tr>
<tr><td>Asset Plan Build Maintain

<u>Pillar</u>: Innovation
<u>Topic(s)</u>:
Enablement
User Experience

<u>Pillar</u>:
Maintenance
<u>Topic(s)</u>:
Vendor Support
Control of
Product Feature
TH Releases</td><td>
The system should allow creation of Work Orders (WOs) and populate an estimate of Maintenance Work
The system must capture:
schedule constraints such as vacation, training and feeder planned outages
crew capabilities,
vehicle / equipment usage
and build an overarching plan with some rules to accommodate corrective deficiency notifications
The system must assist building a schedule with a framework for users to cater to their specific needs, and track progress against the plan based on schedule and financials
The system should assign work orders to inspection work and allow users to assign inspectors to work orders
The system should record the overall goal of the scope item with linkages between the scope package and the regulatory filing, and ensure appropriate approvals are secured within a workflow
The system must allow user to create a maintenance plan for any asset level through work orders and apply some business rules for those assets due for replacement as part of the capital program
The system should process change requests and capture detailed material, labour, and assets required with a view of the impact to the master schedule and secure approvals via workflows
The system should assist program planning activities in a consistent project structure across different time horizons and consider resources, materials and costs calendarized over the life of the program with reporting capabilities
</td></tr>
</table>

	• The system must identify failed assets from planned and reactive work orders with outage / event information and provide a higher-level asset class view to view system issues • The system should allow accruals to a Work Order when an invoice is requested and allow invoice submission based on service entry sheets linked to Work Orders • The system must allow the assignment of Work Breakdown Structure (WBS) to the project development team and assignment of the team costs to the WBS • The system, across applicable business units, must allow sign-off and attainment on receipt of the Green Construction Folder with linkages to the design hours and updated assets • The system must allow the user to close out a design project after the pre-requisites are met and must allow the project to be put on a construction schedule • The system must allow for long terms planning using conditions by asset class and receiving key data measures from other systems to build the scope definition, complete data analysis and to study impact analysis • The system must capture units of work in hours, units of assets, notes and view materials for project planning and reporting purposes • The system must define work packages, relate them to investments, assets, similar and adjoining projects, and use workflows for approvals • The system must track the work package from design to execution with risks defined from a Master List and allow to report on progress • The system will allow users to build the project structure with templates containing breakdown structures and pre-populated data and allow the flexibility to tweak the project structure as needed • The system must allow user to build estimates using applicable methods (e.g. asset assemblies, unit price methods), maintain versions, view design costs and actuals and secure approvals through workflows • The system must record and report construction work completed against a plan line in terms of asset assemblies and schedules • The system must allow users to build packages estimates based on applicable frameworks (e.g. asset assemblies, unit price methods), and summarize the resource and asset needs using Future State data and guided by Historical Trends • The system must allow the user to assign a risk score at the scope, project level and support scenario planning with appropriate versioning • The system must allow the user to issue materials against a work order while applying appropriate checks for quantities and secure approvals in case of exceptions

	The system must capture details when an asset is energized with planned versus actual details of Order to Operate (OTO) and Planned Outage information • The system must retain a record of the assets and their conditions, by location, by asset and by hazard to predict the financial risk and the reactive capital expenditure spend • The system must correlate current feeder loading information, future state studies and estimates from external tools to determine future load • The system must be able to use datasets in the Maintenance Investment Model to identify assets for renewal and perform what-if analysis • The system must allow work assignment to specific Designated Responsible Person (DRPs) with notifications and include in the assignment details on dates, required assets and ability to view progress • The system must allow a Program Manager to assign design projects to specific Project Managers and assign detailed estimates to be completed, and track the time required to complete the work • The system must allow cash flow for the various planning cycles and scenarios and allow carry forward opening balances to the next fiscal year • The system must allow identification of inspection tasks in work orders and the ability to submit inspections after necessary changes and report on the aggregate work completed
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system should provide a workflow to calculate the Net Present Value (NPV) and provide form templates to support user requests for NPV calculations • The system must auto-populate the Offer to Connect (OTC) form with Toronto Hydro's account number in the event customer sends funds via Electronic Funds Transfer (EFT) • The system should allow designers to create a job quotation and secure necessary approvals using a system-based workflow • The system should manage a feeder load request process that considers the work assignment, feeder hierarchy, asset data, costs and basic power flow analysis • The system must evaluate project estimates and accruals at a granular level, calculate NPV, retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance	• The system must provide the ability to record and release Confined Space Hold Off requests against a work order • The system must gather claims data along with the ability to store files and notify when payment is due

Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow work orders to capture time, over-time, cost, materials, notes and link work orders together with ability to report on work orders completed • The system must allow for options to share electronic content within Toronto Hydro and with vendors, customers and the City of Toronto • The system must allow user to schedule planned reactive and planned work orders against crew (vehicle, labour, and time) capacity, and skills • The system must generate reports to view the daily, weekly, and monthly performance of planned and unplanned events by crew • The system must allow the crew to record field work completed, with details on OTO, notes, materials, tools, and equipment needed, and assign notifications, delivery dates and follow up work • The system must allow the user to define and assign forestry work to specific crews, prioritize the jobs and allow the assignee to report back on progress • The system must allow multiple planned work notifications to be scheduled and issued to crews piecemeal with consideration for priority for any unplanned work and for follow up work
Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must pre-populate employee timesheets with schedule and approved absences and must trigger appropriate workflows and notification on submission of timesheets and capture comments, where appropriate • The system must allow consideration and functionality for overtime pre-approval, employee hierarchy for approvals, emergency declaration and exceptions for timesheet submission, per terms of employment and basic timesheet rules • The system must integrate with SAP Concur and map the appropriate general ledger accounts with SAP Concur • The system should process payroll based on the timekeeping records for the pay period and consider the pay codes, tax implications and garnishments, including the retirees, non-Toronto Hydro employees per the applicable business rules
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must calculate the monthly interest due to customers for deposits and process bills or refund customers for the expansion deposits • The system must accept billing financial transactions from Customer Information System and General Ledger (GL) interface and make the necessary adjustments in the GL • The system should calculate the late payment charge for customer accounts and keep a record of applicable late charge rates • The system must apply customer EFT and cheque payments to an invoice and process customer refunds

	• The system should estimate and prepare the bill for customer demand work with consideration for taxes
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow for General Ledger account analysis that supports comments, workflows, attachments • The system must enable deposits against projects with capital contributions and link them to assets and project WBS. • The system must complete calculations to support capital contributions, costs (life to date), deposit balance • The system must generate reports to recognize excess key finances such as excess capital, deferred revenue, contributions realized, deposits, as they pertain to projects and reporting periods • The system must allow user to define Asset Retirement Obligation (ARO) assets with linkages to asset categories and sub-ledgers and support calculation of liability with reports as they pertain to capitalization and derecognition or decommissioning • The system must store and report on Accounts Receivable aging by customer class and groups with trends of balances, revenue and cash flow • The system must have workflows with approvals for elimination and consolidation transactions for journal entries and balances, and report on them • The system must maintain Fixed Asset Continuity and support reports for deferral accounts, regulatory balances, tax assets and liabilities, variances, expenses and recovery • The system must maintain Other Post Employment Benefits (OPEB) liability with opening balance and end liability with expenses, benefits and adjustments, including reports to support analysis • The system must have a template to pole removal that ties to WBSs, accruals, actuals and estimates, that allows for transactions and supports reports for analysis • The system must be able to build a "Road Cut" template to capture specifications from accruals, receipting and invoicing, City Permits and other processes • The system must enable the quarterly schedule of unreconciled differences (SUDs) process with appropriate workflows and audit checks, and reporting capability • The system must support the Allowance for Funds Used During Construction (AFUDC) rules and AFUDC process for projects and support the reports to govern the AFUDC process • The system should manage the end to end debt issuance lifecycle with key inputs and calculations from a tax standpoint and allow for reports to ensure governance

	• The system should estimate preliminary distribution revenue based on rates and regulatory assumption, estimate medium and longer term debt rates, and estimate operational and maintenance expense. • The system must calculate and report on eligible capital expenditures for capital contributions and tax related expenditures such as Capital Cost Allowance (CCA) • The system must provide the ability to calculate effective tax rate. • The system should estimate and allocate corporate shared services based on a number of parameters such as number of purchase orders (POs), payroll, occupancy and provide the option to manually adjust the estimates • The system should track and report the asset lifecycle from procurement to installation to retirement for all asset ty pes including the associated financials records for assets, labour and equipment • The system must identify major assets and support their capitalization while considering the project cost structure • The system must enable asset retirement obligation (ARO) functionality and reporting with calculation of associated liability, discount rate and cost allocations and assess the impact from changes to underlying rates and adjustments • The solution should accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger • The system must allow a user to build a forecast from existing plans, while maintaining version and applying standard allocation and distribution business rules, and secure the necessary approvals • The system must provide reports that compare actuals versus plan versus historical trends with supporting narrative comments for variances and provide the user multiple views of the data • The system must provide the ability to perform a depreciation simulation with capital contribution amortization, including software and leased assets, and issue exception reports • The solution should track and report the asset lifecycle when it is removed against the plan, and consider the impact to the general ledger accounts, capital contribution, and depreciated derecognition value, as needed • The system must have the ability to record the proceeds of disposition of specific assets and account for downstream effects to the relevant account codes, general ledger code and tax • The system must use data from the Customer Information System billing data interface to update the revenue / cost of power general ledger accounts at a customer class level and allow for reporting to validate the accuracy and completeness

	• The system must maintain a separate tax ledger and allow workflows to track documents, adjustments, approvals and reviews. The system must generate reports to support the process • The system must enable reporting of services, goods and invoices that did not charge harmonized sales tax (HST) • The system must provide the ability to produce internal & external financial statements including but not limited to balance sheets, statement of income, statement of comprehensive income, statement of change in equity, statement of cash flows and summary financial information (ratios) with financial data • The system must support the integration with Workiva (i.e. a financial external reporting system) to enable automation for external reporting • The system must allow setup and reporting of deferral accounts to support Ontario Energy Board (OEB) reporting requirements • The system must allow intercompany invoicing, settlements, transactions journal entries, asset transfers and interests administered through workflows to secure necessary and appropriate approvals • The system must provide the daily cash position based on integration with data from Customer Information System, bank information and build a forecast considering business rules on accounts receivable (AR) and accounts payable (AP) parameters • The system should provide the ability to centralize the operational and capital budgeting process through all stages, allowing for multiple iterations • The system must provide the ability to process property tax payable for each Toronto Hydro property in installments per the City of Toronto invoice • The system must be able to identify and estimate the tax treatment based on the location of the supplier, type of service, and location where service was provided, and provide applicable reports • The system must provide the ability to pay provincial payment in lieu of property tax in installments and be able to estimate the first installment payment • The system must incorporate closing (actual) gross fixed assets, undepreciated capital cost (UCC) and accumulated depreciation into the planning process and allow to run different scenarios for tax and financial purposes • The system should be able to calculate and forecast liability by ARO category using inflation rate, discount rate, accretion, payments and adjustment and use budgeted payments to lower liability • The system must allow to account for the following variables in the calculation of electricity revenue for the planning model: cost of power, retailer settlement variance account, rate riders

	• The system must capture and consolidate quantity, vintage and functional locations / region of assets by class to be decommissioned by each business unit, such that each asset is identified and asset quantity is adjusted accordingly • The system should calculate planned HST by month from net income, gross revenue and operational expenditure & capital expenditure numbers entered by the planning team and secure approval via a workflow prior to posting • The system should allow manual or calculated input of pre-capitalized inventory to book the change in pre-capitalized balance • The system should identify the property and estimate future property tax and secure necessary approvals prior to posting • The system must cascade impact from disposition of assets to ARO, capital contribution, revenue recognition of capital contribution • The system must be able to determine the value at cost of meters and transformers held in inventory • The solution must provide the ability to identify all regulatory deferral account (RDA) accounts by category, by nature and by regulatory status and calculate the change from the prior period and apply the changes against specific profit and loss (P&L) accounts, and provide reports to support analysis • The system should transact in multiple currency and revalue balance sheet accounts and maintain foreign exchange (FX) rate in Canadian dollars • The system must download detailed bank transactions and apply them gains GL bank transactions and interface Customer Information System cash receipts to the SAP GL • The system should identify contracts with pre-paid conditions subject to business rules associated with PO, contract, renewals, receipting etc. • The system must apply industry standards to the creation, modification, deletion, backup, restore and other such operations to financial data, records, artefacts and transactions • The system must identify and report, for City of Toronto and its affiliates as vendors or customers, with respect to deposits, payments, accruals, journal entries, revenue, capital contributions etc. • The system must produce reports on Canadian Electricity Association (CEA), total payment to governments, OEB's recordkeeping and reporting requirements, annual statistics Canada, capital expenditure and financial information • The system must support the calculation of a number of key financial metrics on costs, revenue, expenses, rate of return and interest rates to enable strategic planning

	• The system must allow for transfer of assets with the necessary approvals, retain traceability, move the depreciation with the assets and allow for asset re-evaluations
Source to Pay Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must capture detailed information on accruals, invoicing, ledgers, sub-ledgers, operating lease information, goods and services receipted in terms of suppliers, dates, responsibility center (RC), accountant, and district, dates • The user must be able to easily fetch reports to support the month and quarter end analysis with filters such as aging, thresholds, systems (e.g. Customer Information System), Independent Electricity System Operator (IESO) advancements, and to provide a longer term multi-year outlook • The system must allow an authorized user to create and modify POs, PO lines, the approved purchase spend, deliver address and dates with comments and version changes • The system must determine and calculate Engineering and Administration Reclassifications (EAR) eligbility and allow allocation to projects. The system must support reporting of EAR, such as allocation percentage • The system must enable end to end vehicle maintenance, with building plans, modifying them, taking into account skillset, demand and forecasts and reporting • The system must enable the equipment failure tracking process with creation of logs of failure that include time stamps, locations, equipment data, warranties and supporting documentation • The system must provide reports to compare plan vs forecast vs actuals with attributes such as RC, vendors, notes etc. and bring aging inventory and other materials into the forecast • The system must capture vehicle master records, maintenance plans, vehicle parts and maintenance plans, correlate charges against maintenance plans and issue invoices as needed • The system must link a contract to its upstream activity and capture key contract details, electronic signatures, attach POs to the contract • The system must generate a PO for inventory and non-inventory items with linkages to the underlying contract / request for proposal / request for quote / Request for Information (RFX) and report on PO aging and amount remaining on contracts • The system must allow a user to book a vehicle and capture necessary user information. The user must be presented with vehicle attributes and business rules must be applied at the time of the booking • The system must allow the process to decommission vehicles with appropriate inspection submissions and WBSs / IOs

	• The system must allow inventory to be defined by a number of attributes, such as source, lead times, and package details, to manage effectively and to allow complete individual and bulk updates across a number of inventory attributes • The system must allow creation of sales orders, delivery notes and invoices for the sale of scrap material and administering the disposal of other material such as vehicles. • The system must receive an extract of the transactions from the vending machines with transfer of costs to the appropriate charge code and vendor cost administration • The system must provide a framework to capture and manage the vehicle assignment and vehicle collection process • The system must provide a framework to accept vehicle return, administer the inspection, and, lastly, ensure charges are applied against the correct work order • The system must allow users to create / update / delete / define business partners with the appropriate approvals and authorization • The system must allow users with appropriate authorization to define and organize master data with ability to search fields and complete bulk updates • The system must provide the ability to populate vendor scorecard templates with metrics on exceptions, issues, transactions and overall data. • The system must allow for payment of invoices with and without POs applying three way matching where applicable subject to a tolerance factor, facilitate discounts and non-payment when needed, and eliminate risk of duplicate payments • The system must manage debit, credit memo, and update cheque and vendor records based on bank files • The system must allow the administration of holdbacks per the terms in the PO and ensure appropriate approvals and reasons are secured prior to applying the holdback and releasing payment • The system must allow the user to request vehicle maintenance and receive a notification on completion of the work order with start and end times • The system must have the ability to view reservations in terms of forecast, planned and actuals for the different vehicle categories, estimate the depreciated or lease value and ensure appropriate approvals are secured in case of purchase and sale and generate reports for analysis • The system should build a schedule of assets and assist with receipting them. The system should also provide some indicators of the process health and opportunities to flag exceptions

	• The system must prevent double receipting and potential double payment, and it must allow to drop shipped assets directly on site through inventory and non-inventory conversion • The system must allow creation of purchase requisitions consistent with Toronto Hydro's Procurement Policy with the ability to assign it to a vendor, RFQ or RFP process, leverage appropriate workflows to capture approvals and report on key metrics and health of the process • The system must allow the transmission and receipt of electronic documentation with electronic confirmation • The system must enable Ariba to perform RFX related activities and provide necessary organization information to govern the process • The system must enable centralized vendor setup with minimum required information by specific roles and setup must take into account standard terms and those unique to the vendor • The system must report on Key Performance Indicators (KPIs) to monitor performance for the following functions: fleet uptime, facilities response to tickets, warehouse, supply chain • The system must support analytics including spend consolidation opportunities, spend history with ability to drill down into details, view upcoming contract renewals and flag entries that could breach policy • The system must provide the ability to capture any invoiced costs associated with a return order including but not limited to assessment, shipping, refurbishment and warranty costs
Other Requirements Pillar: Innovation Topic(s): User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow all the attributes associated with the following data to be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, WBS and internal order (IO) data, material and vendor master data, purchase order, contract and project data • The system must continue to integrate with other systems such as Customer Information System, Intelex, Remedy, and Royal Bank of Canada to ensure ongoing uninterrupted service • The system should support the industry best practices associated with the document lifecycle and its management in the Meter to Cash process. This would include items such as, quotations, billing, etc.

5.2 Technical Requirements

To address the business requirements, the new S/4 HANA system will need to adhere to the technical requirements below:

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	• The system must meet Tier 1 Service Level Agreements (SLA). • The system must have high availability with an uptime of 99.95 percent and targeted Return Time Objective (RTO) of equal or less than 4 hours and targeted Return Point Objective (RPO) of up to 4 hours of data loss • The infrastructure must adhere to the applicable Toronto Hydro standard for server, Storage Area Network (SAN), backup, database and middleware
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	• User accounts should be authenticated using Toronto Hydro's corporate active directory • User authorizations should be implemented using role-based user groups stored in active directory • User authorizations, existing roles and profiles from SAP ERP need to be migrated to S4 HANA • The system must handle single sign on with the applicable Toronto Hydro standard technology • The at rest data in the databases must be encrypted • Data in the lower environments must be scrambled or masked • The system must adhere to the standards for internal access, external supplier access, security technology, application security, network security and vulnerability management