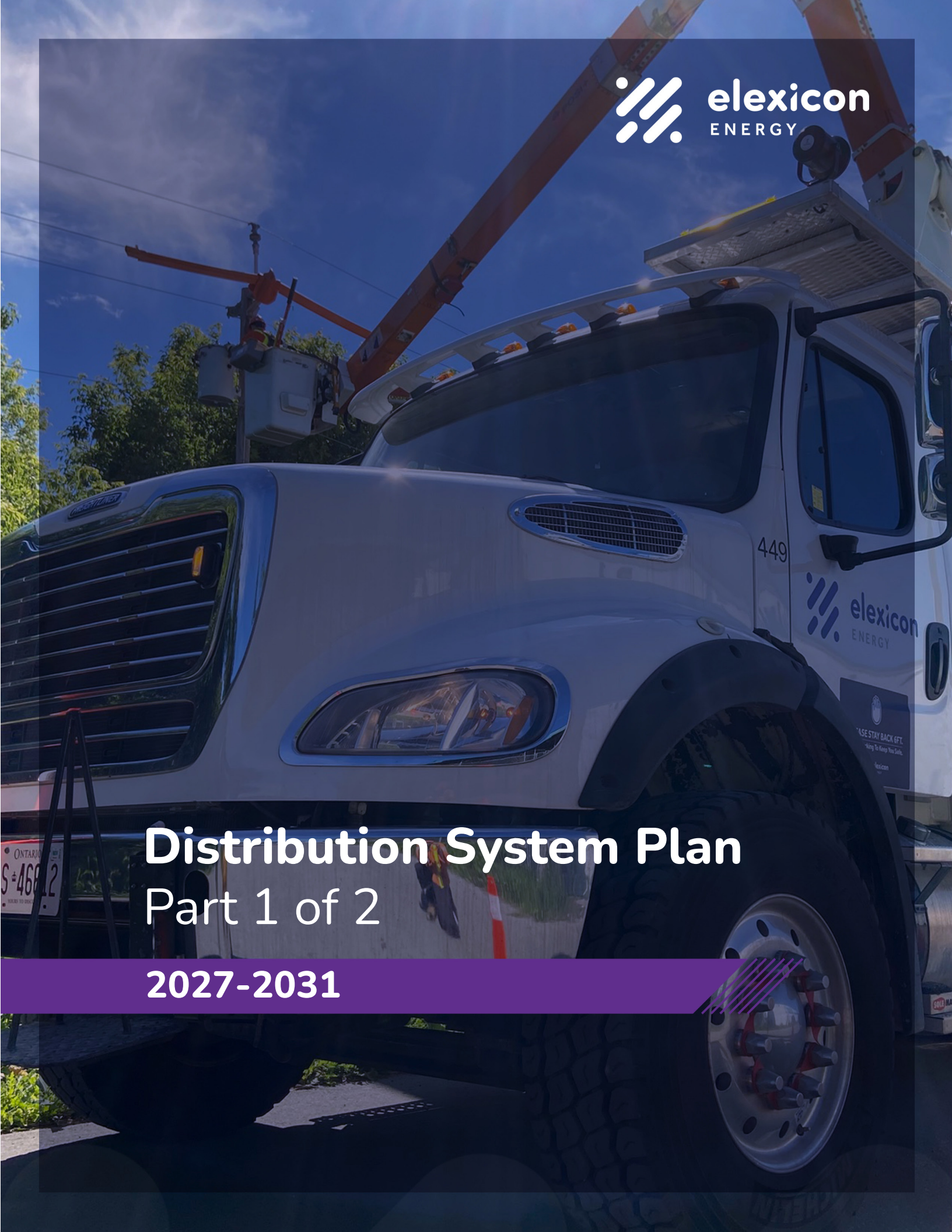


Distribution System Plan

Part 1 of 2

2027-2031

DSP OVERVIEW

1. SUMMARY

This exhibit provides an overview of Elexicon's operating context and current challenges, the inputs to its investment plan, as informed by its customer engagement process, its asset management strategy, as well as an overview of the key investments Elexicon must make to provide safe and reliable power to its customers. These objectives will be achieved by targeted investments across the system, such as investments in capacity through a limited number of new stations, and paced investments in grid modernization to ease constraints and reliability issues while preparing for the future.

1.1 Current Challenges: Capacity Constraints and Persistent Demand

1.1.1 Connections and Load Growth

From 2022 to 2024, Elexicon's service area experienced a 140% increase in the number of connection applications and inquiries over 1 MW, rising from 15 requests in 2022 to 36 in 2024, as noted in Table 1 and Table 3 below. More notably, the total load requirements surged from 28 MW in 2022 to 166 MW in 2024: a nearly 500% increase. This growth was driven primarily in Pickering, which saw its load requests jump from 6 MW to 107 MW, and Whitby, which maintained consistently high volumes of load requests. The data reflects a significant acceleration in development activity and electrical demand across the region. Elexicon has also seen an increase in requests for large load connections over 5MW in 2024 and 2025, to support new distribution centres and manufacturing facilities attracted by efficient access to the Greater Toronto Area ("GTA") and major highways.

Table 1: Number of Connection Applications and Inquiries >1MW

	2022	2023	2024
Total	**15**	**19**	**36**

Across Elexicon's entire system, 76% of municipal substations have less than 1,000 kVA of available capacity, and 70% of transformer station feeders supplying Elexicon substations have less than 1,000 kVA of available capacity. This constrained capacity has resulted in current and potential customers seeking to

connect larger loads (i.e. >500 kW) needing to contribute to system expansion assets to enable their connection requests. Similar constraints exist across Elexicon's feeders. In north Pickering, for example, current loading shows that all feeders are operating at approximately 80% of capacity, with less than 500 kVA of available capacity remaining per feeder. This leaves minimal capacity to serve new subdivisions, commercial or industrial projects. These constraints are further exacerbated by the maximum allowable transformer size of 500 kVA at 8.32 kV (a legacy voltage level) due to technical and equipment limitations, compared to up to 3,000 kVA (utility owned) on the 27.6 kV system, which restricts the ability to connect larger load customers and developers.

1.2 Current Challenges: Deteriorating Assets and Legacy System Voltages

1.2.1 Asset Demographics

Elexicon's asset condition demographics show that approximately 35% of all assets across the system are in fair, poor, and very poor condition. The impact of this aging asset population is also evident in the reliability performance data. Between 2020 and 2024, there has been a 271% increase in Defective Equipment SAIDI and a 151% increase in Defective Equipment SAIFI outages relating to the overhead system. These trends contribute to an overall system reliability decline in both SAIDI and SAIFI performance. Adjusting for loss of supply and major event days, equipment failures are the leading cause of interruptions, and the biggest contributor to Customer Hours Interrupted (CHI) with 30% of all CHI attributed to equipment failures over the historical period.

1.2.2 Legacy System Voltages

While new substations will expand supply into growth areas, some regions of the system still operate at legacy voltages of 4.16 kV and 8.32 kV. These legacy systems are capacity constrained, functionally obsolete and cannot accommodate larger customer connections or support modern system standards. As a result, they represent a barrier to growth and a prerequisite for the decommissioning of aging 4.16 kV and 8.32 kV infrastructure. Elexicon must begin to make investments in the Voltage & System Conversion Program to enable the transition of these areas to standardize 13.8 kV and 27.6 kV systems, allowing larger customers to be served, improving compatibility with new infrastructure, and supporting the safe decommissioning of legacy stations.

1.3 Current Challenges: Inflation and Funding Constraints

1.3.1 Rising Material and Equipment Costs

Over the historical period, and expected during the bridge years, Elexicon experienced unrelenting cost increases for material and equipment. For example, costs for wood poles and pole-mounted transformers have increased by an average of 47% and 73%, respectively, from 2021 to 2024 and are expected to continue rising as the need for grid infrastructure expansion persists across Ontario (details of Elexicon's materials and equipment costs are outlined in Exhibit 1-Tab 5-Schedule 2). These cost pressures impact the volume of work that can be funded without undue rate impact to customers. As costs rise, Elexicon must find ways to more efficiently execute on its capital and maintenance programs.

1.3.2 Funding Constraints and Deferred Rebasing

As a utility in a deferred rebasing period, current rates do not fund the investment needed to respond to the trends that emerged or were amplified over the historical period. As captured in Table 2, the growing need to fund non-discretionary investments in system access eroded Elexicon's capacity to fund renewal programs at the levels warranted by asset condition. Such pressures from non-discretionary spending have resulted in underfunded investments in underground, overhead, and station renewal needed to prevent further degradation of reliability performance. From 2020 to 2024, Elexicon's reported SAIDI rose from 1.37 hours to 1.71 hours. Elexicon's SAIFI results are also on the rise. Without immediate investment, SAIDI and SAIFI is also projected to worsen.

Table 2: Capital Expenditure by Investment Category - % of Overall Spend (2020 to 2026)

	2020	2021	2022	2023	2024	2025	2026
System Access	22%	30%	29%	42%	37%	43%	45%
System Renewal excl. R4 Reactive	39%	38%	27%	21%	22%	17%	15%
R4 Reactive	8%	4%	14%	13%	18%	18%	14%
System Service	10%	13%	8%	9%	13%	10%	17%
General Plant	20%	15%	22%	15%	9%	12%	9%
Total	100%	100%	100%	100%	100%	100%	100%

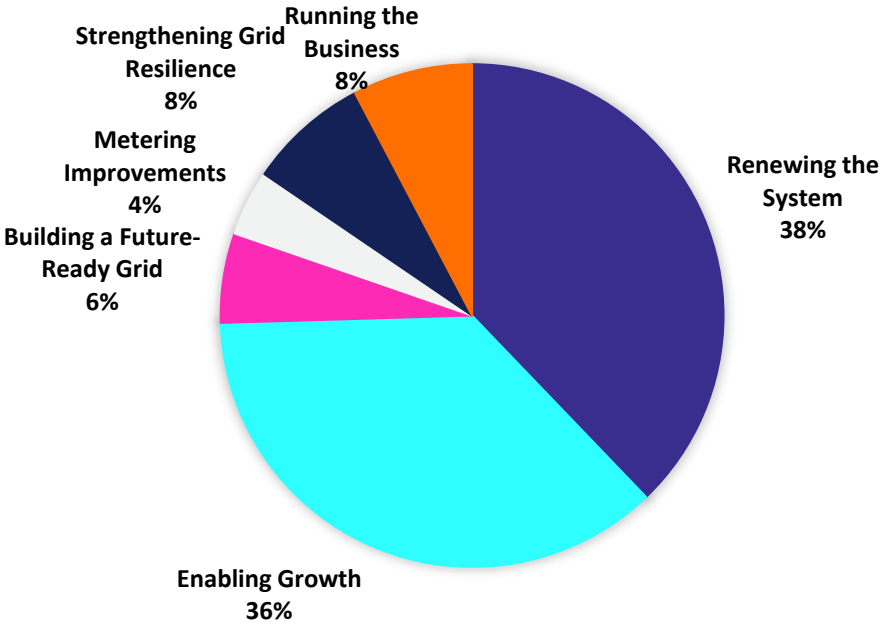
System Renewal investments have seen continued constraints due to the need for Elexicon to balance other competing priorities, including execution of non-discretionary System Access investments, as well as critical Substation Growth investments designed to provide the essential capacity to connect new

customers and support continued system growth. As a result of these constraints, and as evidenced by the current-state age and condition demographics results, there is a growing proportion of assets past their typical useful life (TUL) and in poor to very poor condition. Given the scale of these poor and very poor assets, Elexicon recognizes that it cannot be substantially remediated within the DSP planning period from 2027 onwards to 2031 without a level of investment that poses unacceptable rate impacts.

1.4 Developing the Investment Plan

Following examination of the assets, current capacity constraints, load forecast requirements, and grid capabilities, Elexicon engaged customers on their needs and priorities. After this initial round of engagement, Elexicon developed a draft investment plan. Through this exercise, the utility identified three primary operational objectives that must be accomplished through its 2027 to 2031 Distribution System Plan: 1) address capacity constraints, 2) enable growth, 3) restore reliability to historical levels of performance. Elexicon then tested its draft investment plan with customers, garnering 79% social permission for its draft plan. The spending categories of the plan are captured in Figure 1, below.

Figure 1: Investment Plan Spending Categories as a % of Total Spend (2027 to 2031)



Elexicon's investment plan sets out to address four main areas of concern: current capacity constraints, persistent demand in the forecast period, deteriorating assets impacting system reliability, and lagging technology and grid infrastructure.

1.4.1 Investing in Efficiency and Modernized Systems

To execute a scaled work program efficiently, Elexicon is also implementing a modern Enterprise Resource Planning (ERP) platform (the Dx NEXT project, see Exhibit 4-Tab 1-Schedule 6, Appendix A) that will support data-driven analytics, lifecycle management, standardized data integration, optimized work scheduling, and transparent cost and performance tracking, providing a scalable foundation for investment delivery. Expanded workforce capabilities, along with robust cyber security and digital resilience programs, ensure that increased levels of capital investments and modernization initiatives are executed efficiently and supported by strong operational safeguards, enabling the organization to meet evolving customer needs throughout the forecast period. Elexicon is also investing in its grid modernization infrastructure (See Exhibit 2B - Tab 3 - Schedule 2 - Appendix A), both the OT systems that connect field devices to the control centre, as well as deploying more devices that can provide remote operation during abnormal grid incidents, increased visibility within the system control centre, and laying the foundation for more advanced technologies to improve system performance and manage and control DERs.

1.4.2 Managing Risk and Balancing Affordability with Outcomes

To manage the reliability performance risks while maintaining affordability, Elexicon adopted a risk-informed approach to determine the appropriate level of investment in its planned system renewal, grid enhancements, voltage and system conversion, and AMI 2.0 programs. This approach balances the level of increased costs ratepayers are willing to accept by targeting investments to asset groups that present the greatest risk to reliability. While the proportion of distribution assets in poor and very poor condition will not decline over the rate period, those assets that are in very poor condition and the greatest contributors to equipment failure will see the highest levels of replacement and/or remediation. This targeted investment approach, combined with investments in grid enhancements, and Operational Technology that provides enhanced automation and visibility to address incidents, as well as increased

investment in maintenance programs, can prevent further decline of SAIFI-related performance, and permit SAIDI to return to historical levels of performance by the end of the rate period.

2. INTRODUCTION

This exhibit is structured into four tabs which are organized in accordance with the OEB's filing requirements for the DSP: Chapter 5 Filing Requirements for Electricity Distribution Rate Applications, 2025 Edition for 2026 Rate Applications, December 9, 2024 ("Chapter 5").

- Tab 1, inclusive of this introduction, contains a high-level overview of Elexicon's operating context, current challenges, and its investment plan per section 5.2.1 of Chapter 5.
- Tab 2 contains details of Elexicon's coordination and planning with third parties as well performance measurement per 5.2.3 of Chapter 5,
- Tab 3 includes a fulsome and detailed review of Elexicon's Asset Management Process, per section 5.3 of Chapter 5, and
- Tab 4 contains Elexicon's capital expenditure plan, and a comprehensive description of each investment program across the four OEB investment categories per 5.4 of Chapter 5.

The DSP was also developed in alignment with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications, dated May 7, 2025, as well as the OEB's Handbook for Utility Rate Applications, October 13, 2016. In developing this DSP, Elexicon has also taken into consideration critical policies such as the Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024. As a 2025 filer, Elexicon has incorporated the Guidelines into this DSP on a best-efforts basis.

Elexicon's materiality threshold, as established in Exhibit 1 - Tab 3 - Schedule 1A, is approximately $700,000. This threshold informs Elexicon's description of forecast expenditures, as well as capital variances over the historical period.

In this application, Elexicon has adopted 2020 as its historical baseline. This DSP provides five full years of actuals for all spending programs. Reference to the 'historical period' includes 2020 to 2024, whereas

reference to 2025 and 2026 are considered 'bridge years' and 2027 to 2031 is the 'forecast period', or the 'DSP period' for this application.

2.1 Description of Elexicon's Distribution System & Service Territories

Elexicon serves a non-contiguous service area primarily located within the Region of Durham, extending as far north as Gravenhurst and as far east as Belleville. Elexicon's geographically dispersed service territory spans approximately 787 square kilometres and with 179,017 residential and business customers as of 2024. Elexicon's distribution assets (2024) include:

- 37,253 wood and concrete poles
- 24,289 distribution transformers
- 17,301 overhead switches and underground switchgear
- 4,696 km of overhead conductors
- 2,650 km of underground cables and submarine cables
- 62 municipal substations (4 of which are customer-dedicated)
- 1 municipal transformer station (Seaton MTS)

As illustrated in 4, Elexicon delivers electricity to a range of towns, cities, and municipalities across this broad, non-contiguous service area. The distance between the farthest points in the service area (Gravenhurst and Belleville) is approximately 179 kilometres, which presents several operational challenges. The lack of geographical continuity requires Elexicon to maintain multiple operational centres and field crews across separate regions to ensure timely restoration and customer service. Elexicon must also coordinate electricity supply from numerous Hydro One-owned transformer stations and distribution stations within regions, which adds further complexity to system planning, load forecasting, and operational coordination.

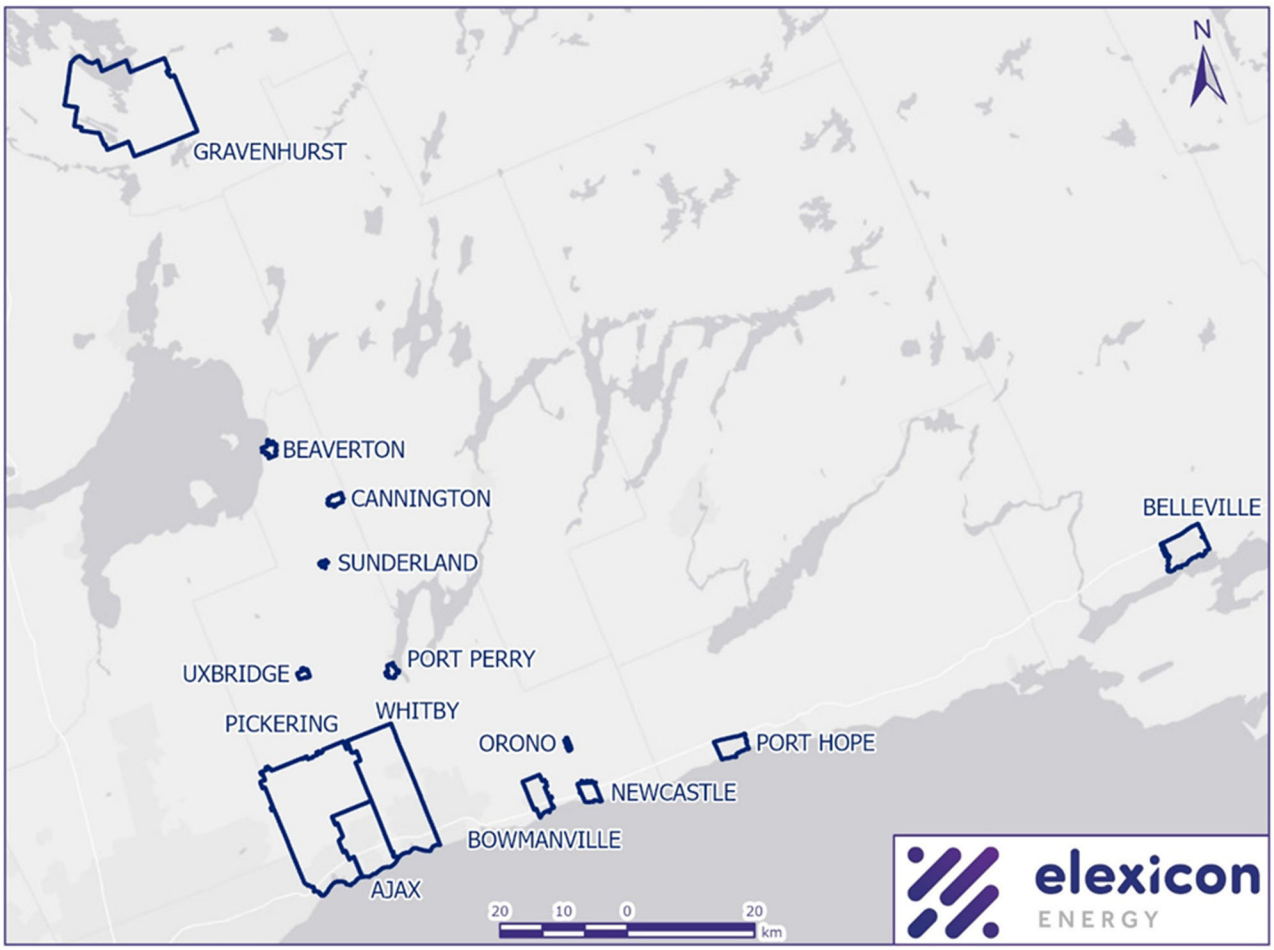
The separation of service areas also limits the potential for load transfer between regions, constraining operational flexibility and complicating contingency planning. It also requires careful prioritization of asset investments, tailored capacity planning, and enhanced operational coordination to ensure consistent

service delivery and support growth across all regions. Despite these challenges, Elexicon continues to provide safe and reliable electricity to its customers across its service territories.

The service area includes several towns, cities, and municipalities across multiple regions including:

- The Town of Whitby;
- The City of Pickering;
- The City of Ajax;
- The City of Belleville;
- The Township of Brock (Beaverton, Cannington, and Sunderland);
- The Municipality of Clarington (Bowmanville, Newcastle, and Orono);
- The Town of Gravenhurst;
- The Municipality of Port Hope;
- The Township of Scugog (Port Perry); and
- The Township of Uxbridge.

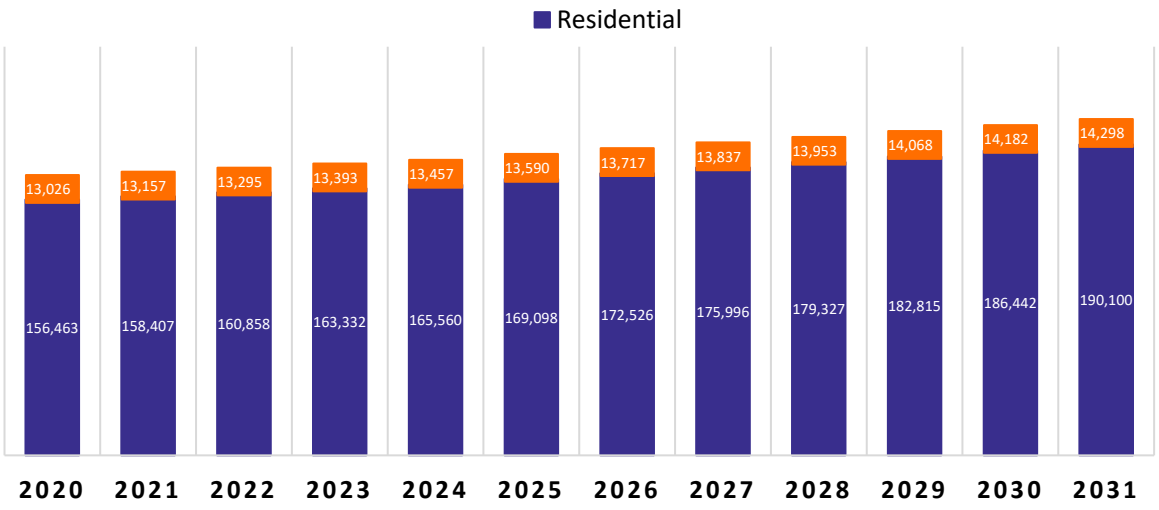
Figure 2: Elexicon Service Area Map



Elexicon's system reflects a history of consolidation, combining multiple legacy networks with varying designs, standards, and voltage levels. This diversity presents challenges for system integration, standardization, and operational consistency. It also complicates investment prioritization and asset renewal decisions, as each legacy network has unique conditions, performance characteristics, and risks. Effectively managing these challenges is essential to maintain reliability, enable growth, and optimize capital and maintenance programs across the service territory.

To better understand the growth dynamics across Elexicon's service territory, Figure 3 below presents customer growth data from 2020 to 2024 (actuals) and 2025 to 2031 (forecasted).

Figure 3: Elexicon Historical and Forecast Customer Growth



Elexicon's anticipated customer growth is tied to broader regional development trends across Elexicon's service area, where several municipalities are projecting increases in both population and economic development over the coming decades. Historically, customer growth averaged 1.4% annually between 2020 and 2024, and the expected average annual growth rate from 2025 to 2031 is approximately 1.9%.

Durham Region remains a significant area of growth within Elexicon's territory. According to the Region's 2025 Monitoring of Growth Trends Report,[1] the estimated population reached 780,065 residents as of December 2024, up from 732,210 in 2021, representing a 2.2% average annual growth rate. Long-term forecasts project Durham's population to grow to 1.3 million by 2051, with employment nearly doubling from 241,660 jobs in 2021 to 460,000 jobs in 2051.[2] This growth is supported by completed infrastructure such as Highways 401, 407, 412, and 418, and ongoing transit enhancements including GO Transit expansions and rapid bus corridors. These investments are catalyzing residential and commercial development, particularly in Pickering, Ajax, and Whitby, where Elexicon is seeing strong demand for new customer connections and capacity upgrades.

[1] Regional Municipality of Durham, "Monitoring of Growth Trends", (May 23, 2025).
[2] Regional Municipality of Durham, "Envision Durham – Regional Official Plan", (December 13, 2024).

Belleville continues to experience steady and planned growth, with its population projected to rise from nearly 55,000 in 2021 to between 70,000 and 81,000 by 2051.[3] This expansion is being driven by strategic initiatives such as the Loyalist West Secondary Plan, which is designed to accommodate up to 28,000 residents, and the Northeast Industrial Park, which supports industrial development and employment growth. Employment opportunities will be provided through a balance of manufacturing, research and development, education, agriculture, tourism, and commercial and industrial uses in areas designated and determined to be best suited for each economic sector. Due in part to the fact that the City of Belleville includes the largest urban area in the Quinte region, it will continue to be the centre of economic activity and employment opportunities. Across Hastings County, the broader population is expected to grow from 173,200 in 2021 to 223,000 by 2051, with employment increasing by over 17,000 jobs between 2023 and 2051.

Northumberland County, the upper tier municipality for the Municipality of Port Hope, is forecasted to reach 122,000 residents by 2051, compared to 89,365 in 2021.[4] Growth is concentrated in municipalities like Cobourg and Port Hope, which are benefiting from improved transportation links, regional migration, and a shift toward mixed-use development. These trends are contributing to increased electricity demand, particularly in residential subdivisions and commercial corridors.

The Muskoka District anticipates a permanent population increase from 66,674 in 2021 to 99,100 by 2051.[5] Growth in this area is driven by both seasonal and permanent housing development, with rising demand in resort communities and recreational zones. Electrification of heating and transportation is also expected to play a growing role in shaping future load profiles.

This sustained population and employment growth contributes to increasing demand on the electricity distribution system and reinforces the need for ongoing investment in infrastructure, capacity upgrades, and system reliability initiatives through Elexicon's service area.

[3] City of Belleville, "Population, Housing, and Employment Growth Forecast Update"
[4] Northumberland County, "2024 Annual Report"
[5] District of Muskoka, "Official Plan 2025"

2.2 Operating Context

This DSP is the second plan filed by Elexicon as a merged entity. Elexicon filed a DSP in 2021 in accordance with the terms of its MAADs decision. The 2021 DSP was informed by the level of funding available in base rates[6], and known plans for future incremental capital projects eligible for ICM treatment. In contrast, this DSP is Elexicon's first DSP as a merged entity that is based on a bottom-up needs assessment of the system and is informed by an asset management process that has evolved significantly since Elexicon's merger, as Elexicon has developed the capabilities necessary to meet customer and regulatory expectations. This DSP is developed as part of Elexicon's Custom IR framework as part of the first rebasing application of the utility as a merged entity. This DSP is also informed by a comprehensive, multi-stage customer engagement process which assessed system needs and customer priorities in detail and across customer classes.

Elexicon's operating context has evolved significantly over the historical period. Population growth and economic activity have created constraints in both the Durham and Quinte regions. Declining reliability performance and improved asset management processes have drawn attention to a growing proportion of aging and poor condition assets in the system with greater failure risk and increasing outage duration.

2.2.1 Persistent and Growing Demand

As noted above, from 2022 to 2024, Elexicon's service area experienced a 140% increase in the number of connection applications and inquiries over 1 MW, rising from 15 requests in 2022 to 36 in 2024, broken down by district in Table 3 below. More notably, as shown in Table 4, the total load requirements surged from 28 MW in 2022 to 166 MW in 2024: a nearly 500% increase. This growth was driven primarily in Pickering, which saw its load requests jump from 6 MW to 107 MW, and Whitby, which maintained consistently high volumes of load requests.

[6] Which were established in the previous utilities' last Cost of Service, 2011 (Whitby) and 2014 (Veridian). Elexicon's 2026 rates are in accordance with the Price Cap IRM.

Table 3: Number of Connection Applications and Inquiries Over 1 MW (2022 to 2024)

District	2022	2023	2024
Ajax	6	6	5
Belleville	1	1	2
Bowmanville	0	0	0
Gravenhurst	0	0	1
Pickering	4	2	18
Port Hope	0	0	0
Uxbridge	0	0	1
Whitby	4	10	9
Total	**15**	**19**	**36**

Table 4: Load Requirements for Connection Applications and Inquiries Over 1 MW (2022 to 2024)[7] by District

District	2022 (MW)	2023 (MW)	2024 (MW)
Ajax	12	19	15
Belleville	3	1	12
Bowmanville	0	0	0
Gravenhurst	0	0	5
Pickering	6	4	107
Port Hope	0	0	0
Uxbridge	0	0	4
Whitby	7	30	24
Total	**28**	**54**	**166**

Overall, customer connection activity has shown a clear upward trajectory over the past decade, with growth rates steadily accelerating. Notably, the composition of these connections has shifted toward larger transformer sizes, as illustrated in Table 5. While the majority of large load customers with transformers connected between 2020 and 2024 fell within the 1,000 kVA to 2,999 kVA range (45 units), there has been a marked rise in the number of transformers exceeding 5 MVA. In 2024 alone, five transformers over 5 MVA were connected, compared to none in the years prior to 2023. This trend reflects a growing prevalence of large user applications and signals a shift in the nature of customer demand toward more energy-intensive operations.

[7] Numbers may not sum due to rounding.

Table 5: Transformers Connected Over 1MVA from 2020 to 2024

Transformer Size	2020	2021	2022	2023	2024	Total
1,000 kVA to 2,999 kVA	6	11	7	7	14	45
3,000 kVA to 4,999 kVA	1	4	3	6	0	14
Over 5,000 kVA	0	0	0	1	5	6
Total	**7**	**15**	**10**	**14**	**19**	**65**

Table 6 further illustrates this trend, showing a substantial increase in the total connected transformer capacity for customers over 1 MVA. Aggregate capacity rose from 13 MVA in 2020 to 61 MVA in 2024. This growth is distributed across multiple municipalities, with Ajax, Belleville, and Whitby contributing significantly to the overall capacity increase. For instance, Ajax saw its annual connected capacity grow from 2 MVA in 2020 to 22 MVA in 2024, while Belleville added 20 MVA in 2024 alone. These developments highlight a clear shift in Elexicon's customer base toward larger, more energy-intensive connections.

Table 6: Connected Transformer Capacity of Customers Over 1MVA from 2020 to 2024

Municipality	2020 (kVA)	2021 (kVA)	2022 (kVA)	2023 (kVA)	2024 (kVA)	Total (kVA)
Ajax	2,000	9,500	9,500	6,000	22,000	**49,000**
Belleville	0	0	2,000	20,000	26,000	**48,000**
Bowmanville	0	0	0	0	1,500	**1,500**
Newcastle	0	1,500	0	0	0	**1,500**
Pickering	8,250	7,000	1,500	0	4,500	**21,250**
Port Hope	0	0	0	8,500	0	**8,500**
Whitby	3,000	10,000	8,250	13,500	7,000	**41,750**
Total	**13,250**	**28,000**	**21,250**	**48,000**	**61,000**	**171,500**

A range of customer types, including households, schools and large commercial businesses submitted more than 150 applications over the 2020-2024 period for DER connections and Elexicon expects interest will continue at a higher pace over the 2027-2031 period based on recent activity, on-going incentives, and improving technology. Elexicon expects an additional 236 DER connections (a nearly 60% increase period-over-period) and 25MW capacity over the 2027 to 2031 period.

Over the historical period, Elexicon needed to fund system access investments while also addressing renewal and capacity at a time when costs escalations for materials and equipment specific to the sector severely outpaced inflation.

The urgent need for system investment over the historical period increased dramatically from the projections of the legacy utilities at the time of merger, as illustrated in Table 7 and 8 below. As illustrated in Table 7, System Access investment has increased by over 300% since 2020.

Table 7: Elexicon's Net Capital Expenditures – Investment Category including ICM (2020 to 2024)[8]

Category	Historical Years (Actuals)					Var. to 2020 (%)
	2020	**2021**	**2022**	**2023**	**2024**	
System Access ($M)	7.015	13.940	19.747	23.426	21.803	311%
System Renewal ($M)	14.967	19.307	24.261	17.264	24.325	163%
System Service ($M)	6.685	13.143	22.022	4.527	17.434	261%
General Plant ($M)	6.523	7.036	12.379	7.328	5.313	81%
Total Expenditure ($M)	**35.190**	**53.425**	**78.409**	**52.545**	**68.874**	**196%**

Table 8: In-Service Additions: Merger forecast & 2021 DSP Compared to Actuals and Bridge Years' Forecasts

$M (without ICMs)	2021	2022	2023	2024	2025 (F)	2026 (F)
Forecast from MAADs application (EB-2018-0236)[9]	29.846	33.307	31.170	31.885	34.538	33.050
2021 DSP (Forecast)	45.356	45.799[10]	35.831	36.025	32.673	35.261
ISA Actuals	46.725	42.787	42.936	37.764	60.773	70.414
Variance to Merger Forecast	**157%**	**128%**	**138%**	**118%**	**176%**	**213%**
Variance to 2021 DSP	**103%**	**93%**	**120%**	**105%**	**186%**	**200%**

2.2.2 Capacity Constraints

Across Elexicon's entire system, 76% of municipal substations have less than 1,000 kVA of available capacity, and 70% of transformer station feeders supplying Elexicon substations have less than 1,000 kVA

[8] Numbers may not sum due to rounding.
[9] Ontario Energy Board, EB-2018-0236, page 27. "Table 8 - Annual Net Capital Investment". Amounts in this table are ISA.
[10] Adjusted to remove Seaton and BRT.

of available capacity. This may render customer projects uneconomical and cause undue delays for residential, commercial and industrial activities essential for the economic viability of the region. Without substantial and timely investments in new stations and the supporting distribution infrastructure, Elexicon will be structurally unable to service the current and anticipated load growth over the next 5 to 10 years.

The lack of adequate capacity in newly developed and developing residential areas pose challenges to enabling residential growth. In North Whitby, load demand on existing substations (the 13.8kV system that supports areas such as Brooklin), is forecasted to reach maximum planning capacity in 2027. Additional distribution system capacity by 2027 is needed to reliably provide electrical services to customers.

The system peak load in the Ajax-Pickering and Whitby regions exceeds the Station Supply Capacity within the 2027-2031 rate period due to confirmed customer requests, the Northeast Pickering Secondary Plan, the Brooklin Secondary Plan, and increasing electrification. Narrowing the focus to the 44kV voltage level, given this is where the constraints lie, Table 9 below outlines the loading utilization at the TS within these areas. This showcases significant overload at three of the four TS in 2025 onwards, and the overall TS 44 kV load exceeds the capacity in the region by 2030.[11]

Table 9: Ajax-Pickering and Whitby 44kV Transformer Station Capacity Utilization Forecast (Summer)

Transformer Station	2025	2026	2027	2028	2029	2030	2031
Cherrywood TS @ 44kV	100%	101%	102%	103%	104%	105%	106%
Thornton TS @ 44kV	100%	100%	100%	100%	100%	100%	100%
Whitby DESN 1 TS @ 44kV	47%	52%	58%	64%	70%	77%	84%
Whitby DESN 2 TS @ 44kV	102%	104%	107%	109%	111%	113%	115%
Total @ 44kV	91%	93%	95%	97%	99%	102%	104%

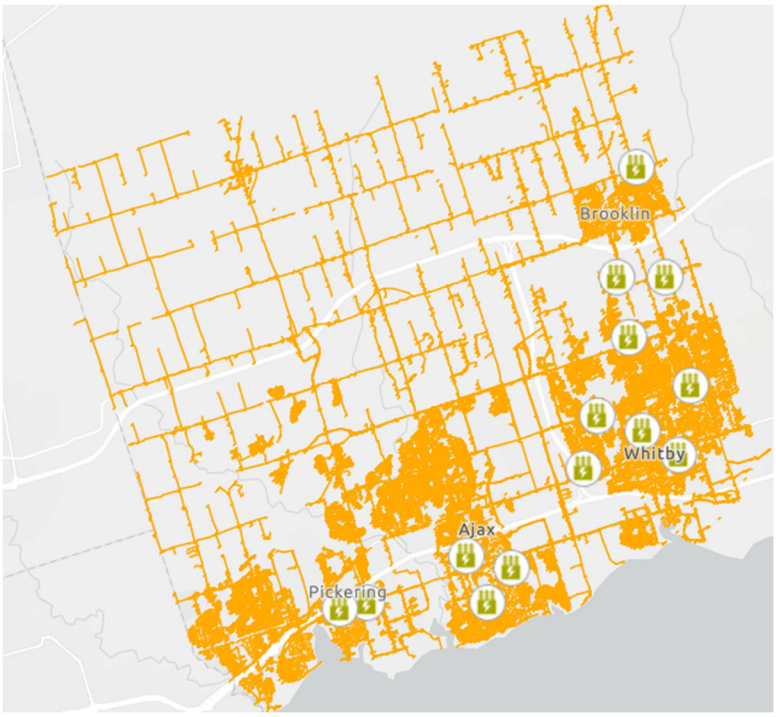
Similar constraints exist across Elexicon's feeders. In north Pickering, for example, current loading shows that all feeders are operating at approximately 80% of capacity, with less than 500 kVA of available capacity remaining per feeder. This leaves minimal capacity to serve new subdivisions, commercial and industrial projects. These constraints are further exacerbated by the maximum allowable transformer size of 500

[11]

kVA at 8.32 kV due to technical and equipment limitations, compared to up to 3,000 kVA (utility owned) on the 27.6 kV, which restricts the ability to connect larger customers and developers.

Elexicon's latest capacity map, Figure 4, below, shows the extent of system constraints in the Ajax, Pickering and Whitby areas. The orange represents feeders with less than 500 kW of capacity, and the yellow station icons denote stations with less than 1,000 kW of capacity.

Figure 4: Elexicon's Capacity Map – Whiby, Ajax, Pickering and Brooklin[12]

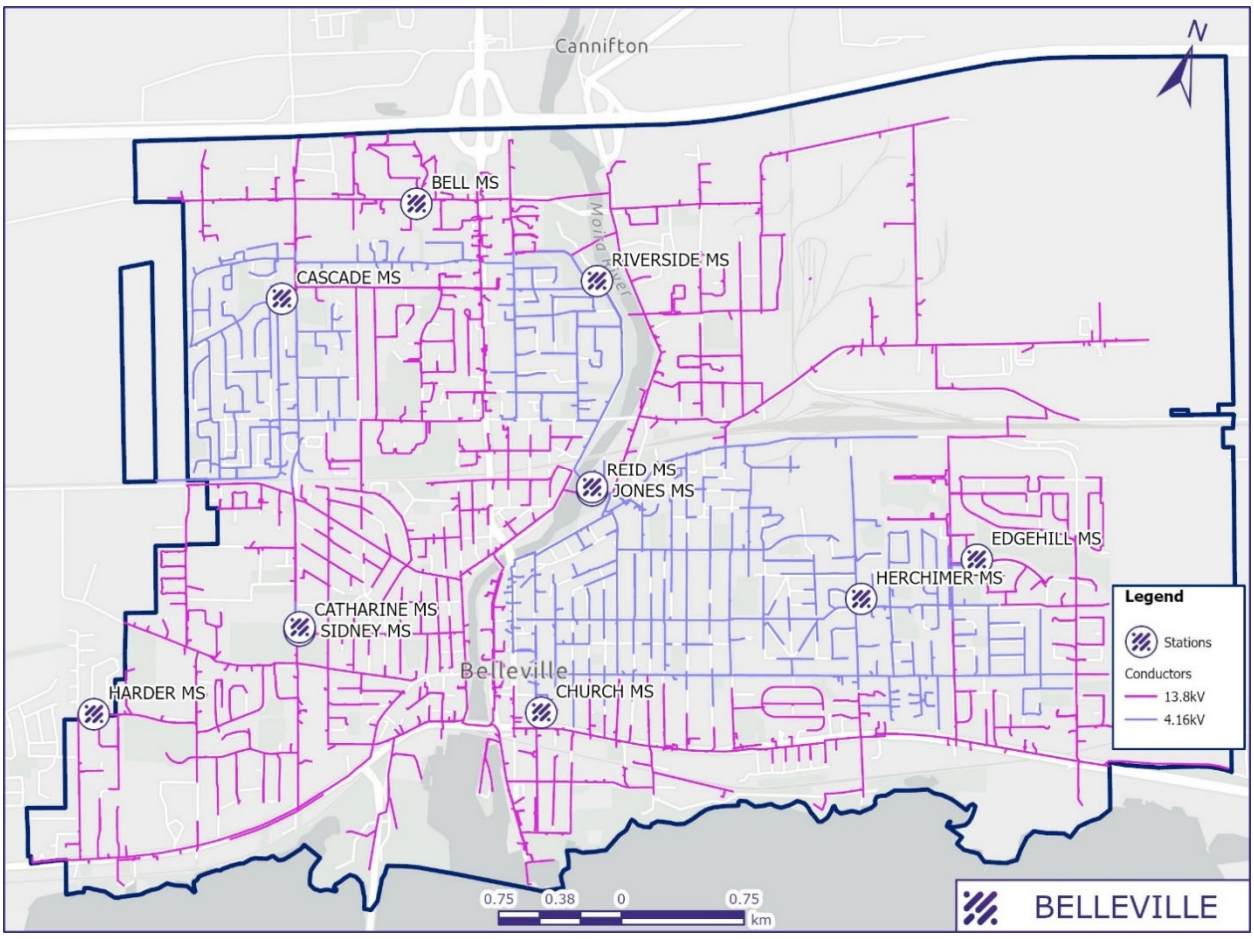


Existing system configurations and legacy voltage levels are also contributing to current constraints. In Belleville, for example, the 4.16 kV substations are operating near their planning capacity are supported by an aging and deteriorating distribution network with majority of the associated assets in Poor or Very Poor condition and approaching end of their Typical Useful Life (TUL). These substations are unable to support continued load growth, particularly in the southeast quadrant of Belleville. As new customers are

12 Elexicon Energy, "Distribution System Capacity Map", (September 15, 2025), https://elexiconenergy.com/contractors-developers/resources/distribution-system-capacity-map#.

added and energy demand increases, the limitations of the 4.16 kV infrastructure are becoming increasingly pronounced. See Figure 5 showing the system voltage map in Belleville.

Figure 5: System Voltage Map – Belleville



2.2.3 Aging Assets & Declining Reliability

As assets age and deteriorate, the risk of equipment failure increases without sufficient investment in system renewal. For Elexicon, this challenge is evident in the asset condition demographics, which show that approximately 35% of all assets across the system are in fair, poor, and very poor condition. It is also evident in the reliability performance data. Between 2020 and 2024, there has been a 111% increase in system Defective Equipment CHI and a 74% increase in system Defective Equipment CI relating to outages

due to equipment failures. These trends contribute to an overall system reliability decline in both SAIDI and SAIFI.

Adjusting for loss of supply and major event days, equipment failures are the leading cause of interruptions, and the biggest contributor to Customer Hours Interrupted (CHI) with 30% of all CHI, attributed to equipment failures over the historical period. Table 10 below summarizes defective equipment associated CHI and CI over the historical period (2020-2024), excluding LOS and MED.

Table 10: 2020 to 2024 Defective equipment CHI and CI

Defective Equipment	2020	2021	2022	2023	2024	Total
CHI (hrs)	49,873	67,016	68,411	97,727	105,055	388,082
CI	39,049	54,700	44,699	51,410	67,814	257,672

Elexicon is currently managing a heightened risk of equipment failure related to aging station assets. When a station fails, extended customer outages can occur, particularly in areas with limited ability to transfer load. The extent of this risk depends on local load transfer capability and existing operational constraints, e.g., planned outages. As load increases, especially as summer system peaks become more frequent, the duration of an outage can be prolonged if neighbouring stations are overloaded. For context, the Ajax-Pickering and Whitby districts recorded their highest peak loads on record in June, 2025 during a significant heat wave event affecting the region.

As of 2025, approximately 14% of station assets are currently in poor to very poor condition, and 28% of station assets have exceeded their Typical Useful Life (TUL) or will exceed their TUL in the next 5 years. These asset demographics foreshadow significant system performance decline if unaddressed in the next five-to-seven years, given the gravity and impact of a station's failures on reliability.

Underground primary cables that serve significant portions of the Durham region present another major risk within Elexicon's aging infrastructure. The utility's underground system consists of 2,624 km of underground primary cables, of which 43.6% is in Poor or Very Poor condition, and 49% is already past TUL or will exceed TUL by 2031. Between 2020-2024, defective equipment was the leading contributor to customer hours interrupted (excluding MED and Loss of Supply), and underground primary cable failures

was the leading contributor accounting for approximately 33% of total defective equipment CHI. Primary cable assets are a significant contributor to the SAIDI Defective Equipment metric, and their deterioration poses a significant and increasing risk to system reliability performance degradation.

Legacy system configuration also impacts Elexicon's reliability performance. In Pickering, customers supplied by the 8.32 kV feeders experience significantly higher outage durations (7.26 hours) compared to those on the 27.6 kV system (1.16 hours). These elevated SAIDI values reflect limited capacity and redundancy, which restrict fault isolation, load transfer, and efficient restoration.

Overhead System Renewal investments have seen continued constraints due to the need for Elexicon to balance other competing priorities, including execution of non-discretionary System Access investments, as well as critical Substation Growth investments designed to provide the essential capacity to connect new customers and support continued system growth. As a result of these constraints, and as evidenced by the current-state age and condition demographics results, there is a growing proportion of overhead assets past TUL and in Poor/Very Poor condition. Given the scale of this proportion of poor and very poor assets, Elexicon recognizes that it cannot be substantially remediated within the DSP planning period from 2027 onwards to 2031 without a level of investment that poses unacceptable rate impacts.

2.2.4 Lagging Technology and Grid Infrastructure

In addition to the challenges noted above related to Elexicon's core mandate of connecting customers, and delivering safe and reliable power, Elexicon is also contending with obsolete, outmoded technologies, and a lack of grid modernization. Over the historical period, Elexicon has identified gaps in both Information Technology (IT) and Operational Technology (OT) that prevent it from further deploying the grid modernization devices that could help alleviate the capacity and reliability challenges noted above. Elexicon has commenced its grid modernization journey through implementing SCADA and ADMS but will need to invest further in the enabling technologies and resources to deploy them, in addition to the field devices that must be connected to these systems, to control electricity flows and monitor and respond to incidents across its grid. Elexicon will also need to ensure its IT and OT hardware is sufficiently modern to be operable with these systems and platforms, in addition to being secure.

Elexicon's grid operations also lack the technology and devices that permit automation and visibility to remotely detect and/or address outages. Over 70% of Elexicon's feeders have no SCADA-enabled switches or reclosers. Of the 30% that do, the number of devices connected to SCADA is limited. This technology is essential for developing modern efficient grid capabilities that reduce the need for manual intervention (i.e. "Truck Rolls"). A SCADA-enabled recloser, for example, can automatically detect faults on the distribution system and momentarily open and close to test if the fault has cleared. If the fault is temporary, the device restores power automatically; if the fault persists, it remains open to isolate downstream affected section of the feeder. This "self-healing" function reduces the number of customers impacted by outages and supports faster, more efficient and targeted isolation minimizing impacts to the upstream customers.

Elexicon is also operating with legacy metering infrastructure. By 2027, 87% of meters will be at the end of their typical useful life. Although such meters can continue to operate if they pass reverification tests to comply with Measurement Canada requirements, they have been rendered obsolete due to the lack of modern functionality compared to newer meters. For example, newer meters can automatically communicate outages (known as "last gasp") to the utility, however 20% of Elexicon's meters do not possess this functionality. Also, since merger, Elexicon has operated with two head-end systems, which are the communication systems that send meter data to the control centre. Maintaining two systems can be inefficient and costly, especially as systems reach end of life and are at risk of communication failures with field devices.

2.2.5 Severe Weather Events and Unique Geography

As described in Section 2.1, Elexicon has a non-contiguous service territory combining rural, urban and suburban regions across ten municipalities. Elexicon operates across service territories that are geographically dispersed with differing climates and geography (i.e. heavily wooded, water-access only, rural). This non-contiguous service footprint presents unique operational challenges during storm events, as restoration efforts must be mobilized and coordinated across isolated regions. Unlike utilities with a single, connected service area, Elexicon's crews must often contend with additional logistical complexities while accessing affected sites, particularly in remote and rural communities. The Gravenhurst service area best exemplifies these challenges due to dense vegetation, island locations, and difficult to navigate

terrain. During storm events, fallen trees, ice accumulation, and damaged infrastructure in these remote locations can result in extended outages if rapid response measures are not implemented.

Elexicon is also contending with weather events that are becoming more severe in terms of the damage caused and the duration of outage. Within less than six months, the Gravenhurst region suffered two major weather events (November of 2024, and March of 2025), that lead to significantly lengthy outages. The November 2024 storm, for example, caused extensive damage requiring 100 hours to restore 90% of customers. Table 11 below captures the most recent major storm events experienced in the Elexicon service territory.

Table 11: Major Storm Events: 2020 to 2024

Event	Date	Customers Affected	Description
Windstorm	July 19, 2020	17,989	• Interruptions lasted ~7.5 hours (to restore 90% of customers) • Adverse weather conditions caused tree contacts, leading to widespread outages and loss of supply
Windstorm	October 23, 2020	2,614	• Interruptions lasted ~18 hours (to restore 90% of customers) • High winds caused tree contacts, downed poles, and fallen conductors, resulting in widespread outages
Windstorm	November 15, 2020	22,892	• Interruptions lasted ~9 hours (to restore 90% of customers) • Wind gusts reaching up to 80 km/h caused tree contacts, downed poles, and fallen conductors, resulting in widespread outages
Windstorm	December 11, 2021	30,471	• Interruptions lasted ~22 hours (to restore 90% of customers) • Winter storm with high winds caused tree contacts and damaged overhead infrastructure resulting in widespread outages
Windstorm	May 21, 2022	126,456	• Interruptions lasted ~70 hours (to restore 90% of customers) • Derecho storm caused extensive damage to Elexicon's infrastructure and led to prolonged power outages to customers
Windstorm	June 16, 2022	22,549	• Interruptions lasted ~26 hours (to restore 90% of customers) • A severe thunderstorm passed through the region of Belleville, resulting in downed trees and conductors

Event	Date	Customers Affected	Description
Windstorm	December 03, 2022	9,727	• Interruptions lasted ~9.5 hours (to restore 90% of customers) • High winds resulted in loss of supply outages for customers in Newcastle
Wind & Snow Storm	December 23, 2022	52,334	• Interruptions lasted ~30 hours (to restore 90% of customers) • An historic winter storm including blizzards, high winds and snowfall swept through the region causing widespread outages. High winds brought down trees and power lines resulting in damage to critical infrastructure.
Snow Storm	January 25, 2023	13,330	• Interruptions lasted ~5 hours (to restore 90% of customers) • A snowstorm swept through the region with winds gusts and heavy snowfall resulting in power outages
Wind & Snow Storm	November 29, 2024	8,879	• Interruptions lasted ~100 hours (to restore 90% of customers) • A severe winter storm struck the Gravenhurst area bringing heavy snowfall, strong windows, and blizzard conditions

2.2.6 Unprecedented Cost Pressures

In the historical period, Elexicon experienced significant cost escalations in materials and equipment that are anticipated to continue. For example, the costs to complete station projects have significantly increased since the last rate period, resulting in higher forecast expenditures primarily attributed to increasing materials costs. In 2020, Elexicon completed a new single transformer MS for approximately $2.5M, and in 2024 a similar MS was completed for approximately $4.5M. Based on material quotations, the current estimate for a new single transformer MS that will be completed in 2027 is approximately $9.9M.

These project cost increases are being driven by equipment and materials costs increasing by >100% over the historical period. A sample of stations components and materials costs impacting capital expenditures is identified in Table 12 below.

Table 12: Stations Equipment Cost Increases

Station Equipment	Price (Reference Year)	Price (Most Recent Year)	Total Price Increase	CAGR
15/20/25 MVA Transformer ($)	782,407 (2020)	1,750,167 (2024)	123.7%	22.3%
LV Switchgear ($)	50,684 (2021)	124,321 (2025)	145.3%	25.1%
HV Switchgear ($)	126,979 (2020)	257,600 (2025)	102.9%	19.3%
1000MCM 28kV Cable ($)	73.42 (2020)	176.58 (2025)	140.5%	24.5%
750MCM 46kV Cable ($)	81.81 (2020)	212.00 (2025)	159.1%	26.9%

2.2.7 Enhanced Focus on Cyber Security

As Elexicon's reliance on digital infrastructure grows, so too does the need to protect critical systems from evolving cyber threats. Elexicon's OT environment which includes SCADA, ADMS, GIS, and DERMS platforms — must comply with the Ontario Cyber Security Framework, which is based on industry standards such as NIST and CIS Controls. These standards require robust identity management, network segmentation, continuous monitoring, and vulnerability management practices. Accordingly, capital investments in OT systems are required to complement the OM&A-driven modernization of enterprise platforms and to ensure end-to-end cyber resilience across both business and operational environments.

Many legacy OT systems are reaching the end of their vendor-supported lifecycle and no longer receive timely security updates, making them increasingly vulnerable to ransomware, data breaches, and unauthorized access. Delaying upgrades increases the risk of system failures during critical operations, such as outage restoration or voltage regulation. Timely investment is essential to maintain system reliability and ensure continued compliance with evolving cyber security standards. A cyber security incident could result in operational disruptions, compromise customer data, and lead to financial losses and reputational damage. These risks are compounded by the growing number of connected devices, which increase the attack surface and complexity of the grid.

To mitigate these risks, Elexicon is investing in system upgrades that enhance cybersecurity resilience. Key initiatives include the implementation of the ESRI Unified Network to improve data accuracy and security within GIS, the expansion of [Redacted] to securely support additional SCADA hardware, and the deployment of an Enterprise Service Bus (ESB) to enable secure integration between OT and enterprise

systems. These investments ensure compliance with regulatory standards, strengthen system defences, and protect the confidentiality, integrity, and availability of operational data.

2.2.8 Evolving policy expectations of LDCs

Changing requirements and expectations of LDCs also impacted the evolution of Elexicon's asset planning framework. Over the historical period, the OEB and the provincial government have introduced policies that significantly reshape how utilities plan their systems, address needs, and prepare for or respond to severe weather. Policy developments such as Non-Wires Guidelines in 2024, and the Vulnerability Assessment System Hardening in 2025, as well as the Capacity Allocation Model (EB-2024-0092), the Distributed Energy Resource Connection Procedures (DERCP), and the Reliability and Power Quality Review.

Elexicon, as with all LDCs, was also required to integrate specific connection processes for DERs and EVs to find opportunities to streamline and clarify the connection process for these types of technologies.[13] The introduction of these new processes dovetailed with the upswing of DER connection requests received over the historical period. As illustrated in Table 13, Elexicon's has received a growing number of DER requests, and expects the level of DER connection activity to persist throughout the forecast period.

Table 13: Generation Connections and Installed Capacity (kW)-

Generation Type	2020	2021	2022	2023	2024	Total # Units	Total Capacity (kW)
BESS	1	4	1	1	0	7	20,483
CHP	0	2	0	0	0	2	2,095
PV	1	3	2	1	3	10	2,498
Sync Gen	1	0	0	0	0	1	800
Roof top Solar	5	9	13	57	46	130	1,081
Total	8	18	17	58	49	150	26,957

Elexicon plans to adapt planning processes and develop new capabilities to address new regulatory requirements and evolving policy expectations such as deploying non-wires solution to meet system

[13] Ontario Energy Board, "Distributed Energy Resources Connection Procedures – Version 2", (originally issued on March 22, 2022, revised version published January 27, 2025), and "Electric Vehicle Charging Connection Procedures", (February 16, 2024).

capacity needs. Elexicon has started to integrate these changes into the Asset Management Planning process. Appendix A of Tab 3 - Schedule 5 contains Elexicon's NWS pre-screening framework. Elexicon will be further developing its capabilities for NWS deployment throughout the forecast period to enhance its system planning toolkit and comply with OEB requirements and policy expectations.

3. DEVELOPING ELEXICON'S INVESTMENT PLAN

Elexicon has built an investment plan that is informed by and responsive to its operating context, the urgent and emerging system needs identified, as well as customer affordability and value-for-money considerations. Through multi-phase customer engagement, Elexicon developed and refined the capital and maintenance investment plans to meet the objectives which will balance delivering value that customers want and need, including responsibly preparing for the future.

To address the challenges of deteriorating reliability, capacity constraints, and a lack of modern infrastructure to unlock efficient grid operations, Elexicon must prioritize those investments to make progress towards addressing these core operational issues, while preparing for future requirements and evolving policy expectations. Elexicon's investment plan was informed by comprehensive customer feedback, (outlined in Exhibit 1 - Tab 7 - Schedule 1 and summarized below at section 3.4.1).

3.1 Strategic Pillars and Focus Areas

Elexicon's corporate strategy is aligned with customer-focused outcomes and enables the utility to build the foundation needed to execute on its investment plan. By setting in place the right focus areas, Elexicon can ensure it has the plans and resources required to achieve the objectives presented to customers in its customer engagement survey.

Elexicon's 2025–2031 corporate strategy identifies four strategic pillars, captured in Figure 6, below:

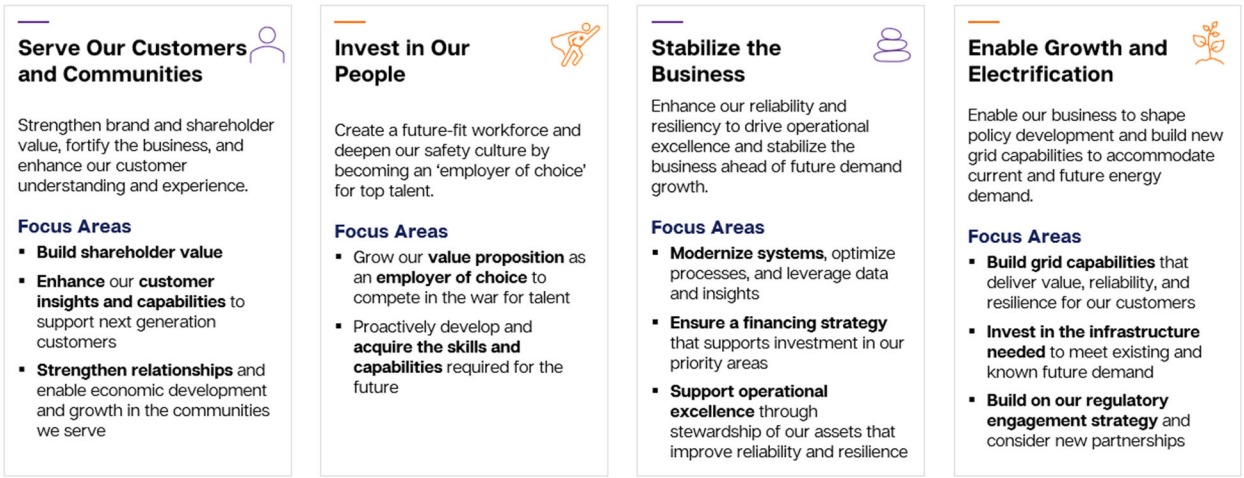
1. **Serve Our Customers and Communities:** This pillar focuses Elexicon on enabling economic growth by focusing on the needs of communities and customers. Key initiatives include strengthening relationships to support growth in the communities Elexicon serves.
2. **Invest in Our People:** This pillar focusses Elexicon on creating the capacity and capabilities it requires in its workforce, including being future-ready and having a robust safety culture. Focus

areas include growing Elexicon's value proposition to attract and retain top talent and proactively develop and acquire the skills and capabilities required to meet needs and preferences of customers.

3. **Stabilize the Business:** This pillar focusses Elexicon on reliability and resiliency of its grid and operations, and driving operational excellence to prepare the business for the requirements of today and future demand growth. Key initiatives include modernizing systems, optimizing processes, leveraging data and insights, and stewarding assets to improve reliability and resilience.
4. **Enable Growth and Electrification:** This pillar focusses Elexicon on enabling economic growth in its service area and building grid capabilities to accommodate evolving energy demands, as well as ensuring it has a robust engagement and considers partnerships where they enable outcomes of value. Focus areas include developing grid infrastructure that delivers value, reliability, and resilience, and investing in the infrastructure needed to meet existing and anticipated demand.

Elexicon's strategy ensures the outcomes of the investment plan are targeted to enhancing customer experience, supporting operational excellence, and building the infrastructure needed to serve a growing and dynamic service territory.

Figure 6: Elexicon's Strategic Pillars (2025 to 2031)



3.2 Priorities

Following its initial phase of customer engagement, as well as rigorous and detailed examination of the age and condition of distribution system assets, current capacity and load forecast requirements, and current grid modernization capabilities, Elexicon identified three primary operational objectives that must be accomplished through its 2027 to 2031 Distribution System Plan: 1) address capacity constraints, 2) enable growth, 3) restore reliability. These objectives will be achieved by targeted and strategic asset replacements across the system, investment in capacity through a number of new stations and feeder enhancements and paced investments in grid modernization to ease capacity and reliability issues while preparing for the future.

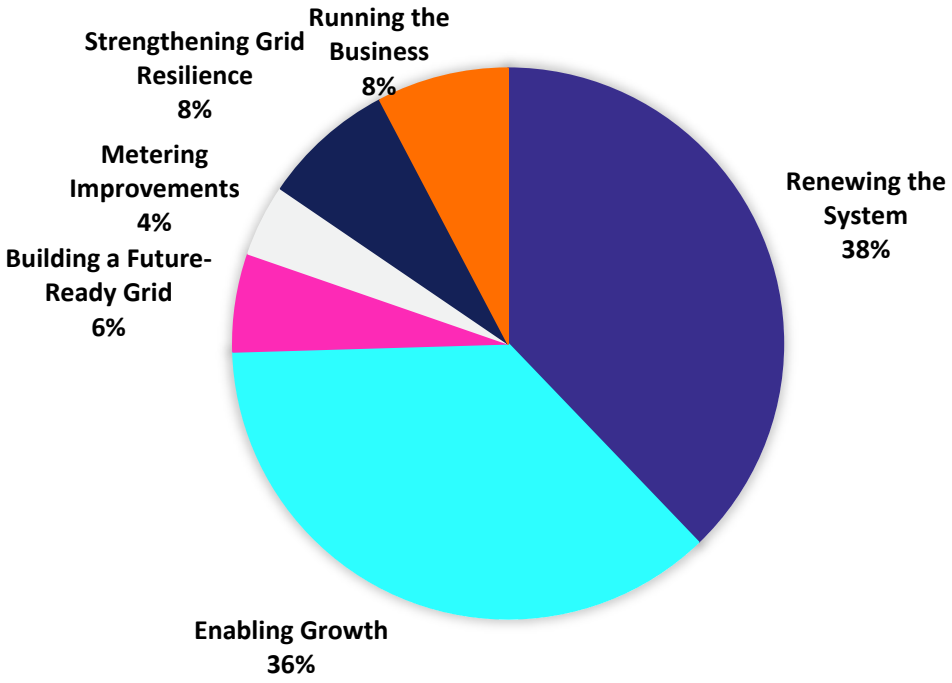
To meet these objectives while considering affordability and customer bill impacts, the investment planning process included developing distinct investment scenarios and weighing the outcomes of each scenario against the cost and risks. Through this exercise Elexicon was able to identify which programs included investments that are mandatory given the utility's obligations under the Distribution System Code and the current state of capacity, and which programs required risk-informed pacing to optimize the balance between outcomes and affordability. The latter programs are those in system renewal, as well as grid enhancements, voltage and system conversion, metering (specifically, the AMI 2.0 project), and general plant investments. The pacing and optimization for those programs was informed by the outcomes of Elexicon's customer engagement survey, as well as analysis of asset age and condition, historical system performance, and risk-informed projections of targeted improvement.

The programs that were paced on a risk-informed basis were aligned to what Elexicon identifies as a 'balanced' investment approach. This 'balanced' approach considered where pacing of investments could be adopted to balance bill impacts against the intended outcomes of the investments. Using this approach, Elexicon assessed its investment plan across all eligible spending categories, constraining investment where possible to balance customer affordability, risk of further performance degradation, and the urgent need to alleviate capacity constraints to enable economic development.

In its Phase II customer engagement survey, Elexicon focused on investments that aligned with the Phase I input and were informed by the risks identified in the Asset Condition Assessment process as well as

system constraints. The proportion of investment in each spending category as a percentage of the overall investment plan is captured in Figure 7 below.

Figure 7: Elexicon's Investment Plan Objectives as a % of Total Spend 2027 to 2031



- **Enabling growth:** These investments include the stations needed to address capacity and enable future load growth; investments for connecting load and generation customers; system expansions through distribution system upgrades such as feeder expansions, and alleviation of existing constraints, as well as externally initiated plant relocation in support of transit and public works and residential expansion in Elexicon's service territories.
- **Renewing the system:** this includes the investments in overhead, underground, and station asset renewal, as well as reactive capital to respond to unplanned events, especially severe weather.
- **Strengthening grid resilience:** these investments include grid enhancements pursuant to Elexicon's grid modernization plan as well as voltage and system conversion to improve reliability and unlock capacity.

- **Running the business:** this includes investments in facilities, fleet, IT, OT, and equipment essential for operations, modernization of IT and OT systems, and to allow Elexicon to scale its business in response to its operational challenges and future growth requirements.
- **Building a Future-Ready Grid:** includes both grid modernization investments, as well as OT investments that support improved system reliability and resiliency, grid visibility and automation, reducing need for manual intervention during faults and laying the foundation for self-healing technologies.
- **Metering Improvements:** investments in advanced metering infrastructure to provide better data, customer meter communication to the control centre, and to support grid modernization objectives.

3.3 DSP Elements

Elexicon's forecast capital plan for this DSP period, 2027 to 2031, comprises targeted and necessary investments aimed at resolving the capacity and reliability challenges noted above, while also ensuring Elexicon can take critical steps towards grid modernization and laying the foundation for grid advancements in the future.

3.3.1 Asset Management Process

Since the formation of Elexicon and the filing of its last Distribution System Plan in 2021, Elexicon has strengthened its asset management processes and built internal expertise to plan, execute, and manage the system effectively. These improvements have enhanced the organization's ability to respond to growth pressures while maintaining reliability and supporting the evolving needs of its customers.

Elexicon continues to mature its Asset Management (AM) Process to enhance data integration, analytical capability, and risk-informed decision-making across the planning cycle. Recent organizational changes integrated Asset Planning and System Engineering functions — bringing distribution system planning, load forecasting, station planning, standards, and system studies under a single coordinated framework. This enables a consistent, system-wide assessment of capacity, reliability, and long-term investment priorities.

The accuracy and completeness of asset data have been strengthened through enhancements to the GIS and enterprise Asset Repository supporting data-driven investment decisions. The implementation of the Elexicon's cloud-based ERP system (Dx NEXT) will further centralize asset, work, financial, and customer data — improving workflow automation, lifecycle visibility, and performance tracking. Maintenance and inspection practices are evolving, incorporating standardized field protocols, and in the forecast period, finding opportunities to leverage AI-enabled vegetation management tools. Elexicon will also employ new monitoring technologies such as communicating fault circuit indicators, enabling a shift toward predictive maintenance.

Elexicon has also refined its load forecasting process through closer collaboration with municipalities, developers, and Hydro One to align distribution planning with regional growth and infrastructure development. Program delivery oversight and enterprise risk management integration have been strengthened, ensuring capital planning and maintenance activities remain coordinated, transparent, and risk informed. Collectively, these enhancements demonstrate Elexicon's commitment to continuous improvement, proactive asset management, and alignment with regulatory expectations and industry best practices.

3.3.2 DSP Continuous Improvement

Since the last DSP, Elexicon has implemented several key organizational and operational changes to strengthen its planning and delivery capabilities. As noted above, a major initiative was the complete revamping of the Asset Planning and System Engineering function, which now integrates Distribution System Planning, Load Forecasting and Stations Planning, Standards, and System Studies under one coordinated framework. This structure enables a holistic approach to identifying system needs, capacity requirements, and reliability priorities across the service territory.

To complement this, Elexicon established a dedicated Program Delivery Group responsible for overseeing the delivery of capital and maintenance work programs which has improved Elexicon's coordination between planning, design, and field operations while strengthening accountability. Elexicon's construction and design teams have also been unified into a single structure to support improved workflows and accountabilities.

Elexicon has also made significant advancements within Grid Operations. The implementation of an Advanced Distribution Management System (ADMS) within the Control Centre has enhanced situational awareness, outage management, and real-time network visibility. In parallel, new emergency management processes including an Incident Management structure successfully utilized during major weather events in 2024 and 2025 that have improved responsiveness and restoration times.

Building on these improvements, Elexicon developed a Grid Modernization strategy that outlines the utility's roadmap for ongoing automation and system enhancement to improve system reliability and resiliency. This roadmap is supported by targeted initiatives such as the Whitby Smart Grid project, serving as early steps toward a more flexible and reliable grid.

In addition, the Dx NEXT project represents a major technology platform investment to modernize core utility systems and strengthen data-driven decision-making. Dx NEXT will enhance integration between operational technologies and enterprise systems, supporting more intelligent planning, efficient operations, and improved customer outcomes.

The outcomes of these continuous improvements demonstrate that Elexicon now has greater visibility into system capacity needs, improved insights into asset age and condition leading to stronger reliability-focused asset interventions, and a demonstrated ability to execute through successful delivery of programs. Collectively, these organizational and technological advancements have enhanced both planning discipline and execution performance, forming a core foundation for the current DSP.

Additional important changes related to life optimization policies and practices are covered in this Exhibit in Tab 3 - Schedule 3, while details on important modifications to capital programs since the last DSP are presented in Tab 4 - Schedule 1.

3.3.3 DSP Objectives

Elexicon's DSP has been prepared to support the four key objectives established in the OEB's Renewed Regulatory Framework (RRF) for Electricity:

- **Customer Focus:** services are provided in a manner that responds to identified customer preferences,

- **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives,
- **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board), and
- **Financial Performance:** Financial viability is maintained; and savings from operational effectiveness are sustainable.

In alignment with the four OEB performance outcomes stated above, Elexicon's plan is anchored on three primary objectives:

- address capacity constraints,
- enable growth,
- restore reliability to historical levels of performance.

Each objective is underpinned by Elexicon's commitment to cost-effective execution of this DSP and balancing affordability concerns with crucial investments in grid assets and modern technologies. To achieve these overarching goals, Elexicon has established the following supporting objectives:

- Optimize asset performance by **leveraging data-driven decision making**, predictive analytics, and asset condition assessments to prioritize capital investments for assets replacement, ensuring long-term system reliability and value.
- Invest in technology (such as Dx NEXT) to efficiently scale capital and maintenance program execution.
- Improve system reliability and resiliency by investing in **targeted system renewal**, automation technologies, and infrastructure hardening in areas with a history of poor performance or increasing outage risk.
- Support customer and community growth by **expanding system capacity** and investing in infrastructure that enables planned development, electrification, and future energy needs across Elexicon's diverse service territories.

- Enhance system **visibility and control** through the continued deployment of SCADA, smart grid technologies, and automation to enable faster fault detection, isolation, and restoration, improving reliability.
- Advance **grid modernization** by investing in technologies that improve system reliability and resiliency and support the integration of Distributed Energy Resources (DERs), Electric Vehicles (EVs), and behind-the-meter innovations, enabling a more flexible and adaptive distribution system.
- Ensure operational effectiveness by implementing a **disciplined, risk-based** capital planning approach and leveraging technology to efficiently scale (i.e. Dx NEXT) so that system needs are balanced with **affordability**.
- Align with **public policy objectives** by incorporating investments to support residential development, economic growth, as well as enabling **customer choice** through DERs, and to enable finding future opportunities to **leverage non-wires alternatives** where possible to meet system needs in accordance with OEB policy.

Collectively, these objectives ensure that Elexicon's DSP supports customer expectations, maintains financial prudence, advances system reliability and capacity, and positions Elexicon to effectively respond to evolving technological and public policy requirements.

3.4 Customer Expectations

3.4.1 Elexicon's Approach to Customer Engagement

To develop its investment plan, Elexicon undertook a two-phase customer engagement process to develop and refine its DSP. The first phase of this exercise established an understanding of customers' needs and preferences which informed the 2027-2031 draft plan. The Customer Engagement Executive Summary report found at Exhibit 1 - Tab 7 - Schedule 1, details the process, methodology and findings of Elexicon's application- specific customer engagement.

During Phase I, customers identified affordability, reliability, and restoration after outages as their top three priorities. Residential customers identified reduction of restoration time after extreme weather

events. Customers also indicated support for grid modernization through the use of new technologies for system performance improvement.

Following Phase I, Elexicon developed a draft plan informed by these customer preferences, priorities, and system needs. Having received feedback on the importance of affordability, Elexicon developed a balanced investment plan which assessed risk, cost, and expected outcomes for customers. This balanced plan was proposed to customers during Phase II of the engagement process, focusing on six investment categories: renewing the system, enabling growth, strengthening resilience, building a future ready grid, improving metering, and running the business. Customer feedback from Phase II indicated broad support for the plan with 79% social permission. After Phase II, Elexicon updated its plan with the latest information related to new connections, forecast costs, and then made adjustments to ensure that the balance of outcomes and cost remained similar to what customers supported in the survey. Elexicon made some reductions to investments programs to offset cost increases in other areas in order to deliver the same outcomes at similar cost.

4. CAPITAL EXPENDITURE PLAN OVERVIEW

Elexicon's Asset Management and Distribution System Planning process, as informed by customer feedback, results in a comprehensive and prudent level of capital investment that will address capacity constraints, prepare for customer and load growth, and restore reliability to historical levels of performance. As noted above, for programs that were conducive to pacing – i.e. where investment can be staged to address the most pressing risks – Elexicon proposed varying levels of investment to customers and the trade-offs and risks of those scenarios. The final plan was informed by customer preference for a balanced scenario that prevents further performance degradation but does not fundamentally change asset demographics. Rather, the proposed timing and level of investment, and the types of assets targeted for investment will mitigate the severest risks. This pacing in system renewal, coupled with system service investments such as grid modernization, will help to improve system reliability and resiliency.

Elexicon's planned expenditures, discussed in detail in Tab 4 - Schedule 1 of this exhibit, are presented in Table 14 below. This plan incorporates customer feedback, balances risks and customer outcomes, and enables investment in system needs that will address current constraints and enable future growth.

Elexicon's DSP features sixteen programs across the four primary investment categories: System Access, System Renewal, System Service, and General Plant.

Table 14: Historical and Forecast Capital Expenditures (with ICM-funded additions embedded)

Category	Historical					Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	Actual	Actual	Actual	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan	Plan
System Access												
Gross ($M)	22.09	33.07	42.19	58.67	44.73	40.65	45.72	99.89	66.09	63.38	70.20	74.59
Contributions ($M)	15.08	19.14	22.44	35.25	22.93	17.83	21.57	66.17	40.27	33.28	37.87	41.15
Net ($M)	7.02	13.94	19.75	23.43	21.80	22.83	24.15	33.73	25.82	30.10	32.33	33.44
System Renewal												
Gross ($M)	14.97	18.50	24.27	17.68	24.97	21.24	22.20	31.31	53.66	56.03	68.76	70.23
Contributions ($M)	0.00	(0.81)	0.01	0.42	0.65	1.07	-	-	-	-	-	-
Net ($M)	14.97	19.31	24.26	17.26	24.33	20.17	22.20	31.31	53.66	56.03	68.76	70.23
System Service												
Gross ($M)	6.69	13.31	22.14	4.85	19.63	11.21	30.79	44.57	39.84	46.80	35.39	72.17
Contributions ($M)	-	0.17	0.12	0.32	2.19	0.61	5.03	-	-	-	-	-
Net ($M)	6.69	13.14	22.02	4.53	17.43	10.61	25.76	44.57	39.84	46.80	35.39	72.17
General Plant												
Gross ($M)	6.52	7.04	12.46	7.41	5.31	6.15	5.09	13.73	10.42	16.81	12.53	12.31
Contributions ($M)	-	-	0.08	0.08	-	-	-	-	-	-	-	-
Net ($M)	6.52	7.04	12.38	7.33	5.31	6.15	5.09	13.73	10.42	16.81	12.53	12.31
Total Gross ($M)	**50.27**	**71.92**	**101.06**	**88.61**	**94.64**	**79.25**	**103.80**	**189.50**	**170.00**	**183.02**	**186.88**	**229.29**
Total Contribution ($M)	**15.08**	**18.49**	**22.65**	**36.07**	**25.77**	**19.50**	**26.60**	**66.17**	**40.27**	**33.28**	**37.87**	**41.15**
Total Net ($M)	**35.19**	**53.43**	**78.41**	**52.55**	**68.88**	**59.75**	**77.20**	**123.34**	**129.73**	**149.74**	**149.01**	**188.14**

4.1 System Access: $ 155.42 M (Net)

The System Access category is comprised of investments in the following four programs, and the proportion of spend in each program is indicated as a % of the total category.

Externally-Initiated Plant Relocation (19%) – This program is designed to manage any and all relocation of Elexicon assets as driven by coordination between Elexicon customers and third parties, including the ten municipalities in east central Ontario: Ajax, Belleville, Brock, Clarington, Gravenhurst, Pickering, Port Hope, Scugog, Uxbridge and Whitby, as well as Durham Region Transit and Metrolinx. Elexicon will leverage these relocation opportunities to replace impacted assets in poor or very poor condition.

Customer & Generation Connections (27%) – This program is designed to manage the connection of new customers, DERs/microgrids, and communities to Elexicon's system. This includes the day-to-day connection of new customers, connections to new residential developments, overhead and underground service connections and upgrades, as well as transformer upgrades to account for customer growth.

System Expansion (35%) – The System Expansion program fulfils Elexicon's mandated service obligations under the DSC by providing the necessary expansions required to connect new customers or accommodate customer-requested load increases. Where existing distribution infrastructure lacks sufficient capacity or does not extend to a new development area, Elexicon must expand its system to meet the customer's capacity requirements at their location

A4 Metering/AMI 2.0 (20%) – This program is designed to manage Elexicon's advanced metering infrastructure (AMI), including residential, commercial, interval, collector and wholesale meters, as well as the underpinning technologies supporting this metering infrastructure that return customer loading data as well as last gasp information to the utility. This program also includes the upgrading of existing metering infrastructure to the next generation of technologies (AMI 2.0) over eight years starting in 2028.

System Access investments over the forecast period are driven by customer service requests, third party infrastructure development requirements, and other mandated service obligations. Elexicon forecasts to connect approximately 18,000 new customers and 236 new generation connections over the 2027 to 2031 rate period. Residential customer growth is expected to average 1.9% annually, and commercial and industrial customer growth is projected at 0.8% annually. These projections reflect ongoing housing completions, population increases, and economic growth throughout the region.

Forecast spending in this category reflects ongoing and known connections and expansions in the earlier years of the plan, whereas spending in the outer years is informed by historical trending, anticipated load growth and demand, and is subject to fluctuations due to externally driven economic factors.

Overall, the level of funding proposed aligns with the anticipated projections of load and customer growth, and through system expansions addresses current and future capacity constraints, while investments in AMI 2.0 further Elexicon's grid modernization objectives and provide technological capabilities that supports improved outage management and grid operations.

4.2 System Renewal: $ 279.98 M (Net)

The following is the list of programs comprising the System Renewal portfolio:

Substation Renewal (39%) – This program is designed to manage the failure risk associated with all substation infrastructure, including power transformers, switchgear, circuit breakers, DC battery systems, station egress cables, protection & control equipment including relays.

Underground System Renewal (30%) – This program is designed to manage the failure risk associated with all underground infrastructure across Elexicon's service area, including underground & submersible cables, pad-mounted & submersible transformers, vault transformers, underground switchgear as well as accessories such as transformer elbows.

Overhead System Renewal (20%) – This program is designed to manage the failure risk associated with all overhead infrastructure across Elexicon's service area, including wood & concrete poles, pole-mounted transformers, overhead switches, overhead conductor, overhead reclosers, as well as associated accessories, including insulators, arrestors, animal guards, cut-outs and sleeves.

Reactive Capital (11%) – This program relates to the reactive spending associated with the unplanned replacement of assets, necessitated by asset failures, outages, and high-risk-and-priority deficiencies identified through maintenance activities. The program also addresses replacements required due to unforeseen events, including damage caused by extreme weather conditions such as storms, high winds, flooding, and other climate-related impacts that can compromise system reliability and asset integrity.

System Renewal investments focus on replacing, refurbishing or rejuvenating aged, deteriorated, or functionally obsolete assets to maintain safe and reliable service. These programs are primarily driven by asset condition, end-of-life considerations, and asset failures. Elexicon's System Renewal investment planning leverages the analytical insights obtained through the Asset Management Process discussed in Tab 3 - Schedule 1, including such items as the Asset Condition Assessment (ACA) framework, ongoing reliability data analysis into system events and trends including the Worst Performing Feeders review (WPF). The proposed investments reflect a proactive approach to maintain system performance, safety, and resiliency following a period of constrained investment levels which contributed to a growing proportion of assets in poor and very poor condition.

Elexicon's system renewal forecast focuses on urgent and critical projects, targeting assets at the highest risk of failure. Elexicon's stations renewal program forecast represents a step change in investment from the historical and bridge periods given its funding constraints and cost increases for materials and components over the historical period. As described in Elexicon's inflation exhibit, (Exhibit 1 - Tab 5 - Schedule 2), the costs for stations equipment have more than doubled over the historical period. The level of investment in stations renewal is fundamental to addressing reliability performance as stations failures result in prolonged outages affecting larger groups of customers and entail costly emergency repairs.

A similar step change is forecast for the level of investment in the underground renewal program. A significant portion of CHI (~40%) related to equipment failures is due to underground infrastructure and asset demographics indicate ~52% of underground assets are in Fair, Poor, or Very Poor condition. These conditions can only be improved through a ramp up of targeted investments. Within underground renewal, Elexicon will focus spending in 2027 to cable injection and underground transformer and switches asset classes, and then escalate investment across all underground assets in 2028 to 2031. The significant investment within underground renewal, although a marked departure from the historical period, does not fully address the risk posed by the condition of underground assets; Elexicon expects such level of investment will need to be sustained through multiple rate periods to contain the risks posed by aging and deteriorating underground equipment. In the 2027 to 2031 period, Elexicon will focus on assets posing the greatest risk to reliability performance, and deploy cost-effective measures, such as cable rejuvenation where possible.

To restore reliability performance, Elexicon will also need to address overhead assets and increase the level of investment in this program relative to the historical and bridge periods. Between 2020 and 2024, there has been a 271% increase in Defective Equipment SAIDI and a 151% increase in Defective Equipment SAIFI outages relating to the overhead distribution system. Continued deferrals would compound reliability challenges, leading to more frequent and prolonged outages. Over the forecast period, overhead asset age and condition demographics will actually not improve, but system performance is expected to improve through targeted investment for assets at highest risk of failure (such as very poor condition assets). Elexicon is proposing a balanced scenario for the overhead program that aims to focus on the replacement of the worst performing wood poles, transformer, overhead switches and overhead sleeves and connections in 2027, recognizing that overhead sleeves and connections are expected to remain one of the leading contributors to Overhead System Defective Equipment reliability. In subsequent years, the need for investment increases to manage the replacement of additional overhead asset classes, including overhead transformers, single-insulator in-line switches, porcelain hardware as well as rear-lot infrastructure conversion.

Although Elexicon's planned renewal is increasing, Elexicon anticipates the level of reactive work to persist throughout the forecast period. Elexicon's reactive forecast ($30.2M) is consistent with level of reactive spending in the historical period ($29.7) but is a decline relative to 2024 and the Bridge years. Similar to other programs, the level of reactive funding needed vis-à-vis the level forecasted in this investment plan is also risk-informed, as Elexicon anticipates that severe weather events, such as those experienced in Gravenhurst in late 2024 and early 2025, are likely to recur.

Reactive spending is not expected to decline relative to the historical period despite the planned renewal investments outlined above. As detailed in the program narrative at Exhibit 2B - Tab 4 - Schedule 3 Appendix H, the proportion of aging and deteriorating assets across the system will not decline over the rate period, and as a result, emergency repairs and reactive work is expected. To materially reduce the proportion of assets in poor and very poor condition would require much higher costs to customers over the 2027 to 2031 term. Given these asset demographics, a reduced amount of reactive spending over the five-year period, relative to the historical period, is unrealistic. The level of investment required to

meaningfully reduce the need for reactive work was rendered untenable through multiple rounds of customer feedback.

Elexicon expects a combination of capital investments in renewal, as well as system service (grid enhancements and modern grid technology) and maintenance investments including increased distribution and substation maintenance programs and program enhancements in vegetation management improvements, will all contribute to improved reliability and reduced restoration and mitigate reactive capital needs relative to the 2024 to 2026 period.

4.3 System Service: $ 238.77 M (Net)

The three programs within the System Service investment category are listed and described below:

- **Substation Growth (62%)** – This program is designed to address current and future system capacity needs by investing in new stations or capacity upgrades at existing stations, which enables Elexicon to connect new customers while improving reliability and resiliency of the electrical system.
- **Grid Enhancements (28%)** – This program is a strategic investment in distribution and station modernization, system capacity and reliability improvements, and targeted station relay upgrades to improve system reliability and resiliency. This program includes the deployment of automated switches, fault detection technologies such as communicating fault circuit indicators (CFCIs), self-resetting fuses, smart reclosers, substation relay replacements, station modernization, and distribution capacity and reliability enhancements. These investments will contribute to a more adaptive and resilient distribution system that will have increased capability of self-healing, enhanced remote monitoring and operation capabilities, and proactive fault detection.
- **Voltage & System Conversion (10%)** – This program is designed to manage the conversion of assets operating at legacy voltage classes (e.g. 4.16 kV and 8.32 kV) by replacing aging and deteriorated infrastructure to mitigate capacity constraints, enhance power quality, and enhance safety and operational efficiency.

The level of investment in the System Service category is based on Elexicon's load forecast, reliability analysis, and the outcomes of the Regional Planning Process, among other inputs described in Tab 3 -

Schedule 1. Elexicon's forecast System Service investments over the 2027–2031 period are driven by necessary projects to address system capacity constraints, enable growth, improve system reliability and resiliency, enhance operational flexibility, and progress grid modernization.

Elexicon's service territory is experiencing sustained growth in population, employment, and infrastructure investment, all of which have a direct impact on electricity demand and system planning. This pace of growth has created constraints at a significant portion of its stations, as exemplified in the capacity map at Figure 2, above. These constraints require urgent investments to be able to support load growth and timely connections. In 2025, 44 of Elexicon's 58 stations,[14] or 76% of stations have limited capacity (<1,000 kVA). Most of these stations are in Ajax, Pickering, Whitby, Belleville and Brock, and the load growth in these regions is forecasted to continue, exacerbating these capacity constraints. By the end of 2031, the proposed investments in stations capacity will reduce the number of constrained stations to 21, or 36% of the total number of stations. Future investments will be required post-2031 to continue reducing the capacity constraints in Elexicon's service territory.

The investments in the Substation Growth program align the projects with the timing of when the need is expected to materialize. Over the 2027 to 2031 rate period, the program plans to deliver one new TS, four new substations and a capacity upgrade at one existing substation.[15] This will add 101 MVA of Distribution System Capacity and 180 MVA of Station Supply Capacity.

Table 15: Municipal Station Capacity: Current State and with/without proposed investment

Capacity	Number of Elexicon-owned Municipal Stations: 58		
	Current State	State without Investments (by End of 2031)	State with Investments (by End of 2031)
Limited Capacity (0 – 1,000 kVA)	44	47	21
Moderate Capacity (1,001 – 2,000 kVA)	2	2	3
Acceptable Capacity (2,001+ kVA)	12	9	36

Realizing the full benefit of these upstream investments requires corresponding downstream feeder-level enhancements to distribute the added capacity and maintain redundancy under N-1 conditions, which will

[14] Total number of stations is 62, four of which are customer-owned.
[15] GTA East TS and new municipal stations in North Whitby (Winchester West MS), Belleville (Foster MS), Port Hope (Port Hope MS), and Uxbridge (Uxbridge North MS), as well as a Mobile MS.

be acquired through the Grid Enhancements program. The Distribution Capacity and Reliability Enhancements segment addresses these concerns by investing in feeder and pole line upgrades, sectionalizing improvements, and tie-points that extend and interconnect new supply paths. Upgrading conductor size reduces line losses, mitigates voltage drops, and increases the feeder's thermal capacity providing support during contingency and peak load conditions. Larger conductors also support distributed energy resource (DER) integration, ensuring the grid can handle bidirectional power flows from solar PV, battery storage, and electric vehicles.

Urban growth and electrification are driving need for additional capacity and more efficient utilization of infrastructure across Elexicon's service territory. While new substations are planned to add capacity on standardized 13.8kV and 27.6kV voltages, some areas still operate at legacy voltages of 4.16 kV and 8.32 kV which are also capacity constrained. These legacy systems are functionally obsolete, do not meet modern standards and are unable to accommodate larger connections, creating barriers to growth.

The Voltage and System Conversion Program transitions these regions to modern and standardized 13.8 kV and 27.6 kV systems. This enables load growth, larger customer connections, and supports decommissioning of aging legacy substations that have reach end of life. Priority areas include Port Hope, Pickering and Belleville where capacity constraints and aging substations are driving the need for system conversion.

The Grid Enhancement investments will contribute to a more adaptive and resilient distribution system with improved self-healing capabilities, enhanced remote monitoring and control, and proactive fault detection. The primary drivers of this program support the continued enhancement of system reliability through Grid Modernization and to address capacity constraints across Elexicon's distribution network. Reliability investments will focus on improving outage restoration times and fault isolation capabilities, while capacity-driven investments will support load growth and enhance system redundancy and contingency capabilities.

4.4 General Plant: $ 65.80 M (Net)

The General Plant investment category includes upgrade or renewal of non-distribution system assets such as Elexicon's workspaces and warehouse facilities, vehicles, tools, and IT hardware/software. The

investments within this program will improve the condition and usefulness of existing non-system physical plant and support capital/maintenance program execution. This category consists of the following programs:

- **Facilities Management (22%)** – This program manages the renewal, repair, and refurbishment of Elexicon's work centres, station buildings, offices, and warehouse space to support increasing workforce levels, current storage and warehousing space constraints, as well optimizing existing space to house greater volumes of materials and the additional vehicles required over the DSP period. Investments include condition-driven repairs, office renovations, and warehouse upgrades to maintain functional, safe, and secure facilities. These initiatives ensure Elexicon's physical infrastructure effectively supports operational requirements and near-term workforce and storage needs as the capital work program scales up to deliver more planned capital than the historical period.
- **Fleet (27%)** – This program is designed to manage the renewal, repair, and expansion of Elexicon's fleet assets. It includes the replacement of aging or end-of-life vehicles, as well as investments in new vehicles to support workforce growth and evolving operational requirements. Fleet availability directly supports timely system maintenance, outage response, and capital program delivery.
- **Information Technology (IT) Systems (16%)** – This program is designed to manage the renewal and upgrading of IT infrastructure that represents the foundation of Elexicon's 24/7 operations. This program will manage the replacement, repair and rehabilitation of IT hardware, servers and data centres, printers and accessories. IT initiatives within this program include printers and copiers, hardware and network equipment needed to enable and support technology investments, strengthen cyber security, and provide sufficient hardware for increasing workforce levels.
- **Tools & Equipment (8%)** – This program is designed to manage the renewal and provision of tools and equipment essential for Elexicon's operational departments, including Lines, Substations, and Fleet. The program supports safe, efficient, and effective day-to-day operations, including construction, maintenance, testing, and other field activities. Equipment covered includes lines,

stations, metering, mechanical, measuring and testing devices, communications, and stores equipment, ensuring crews have the resources needed to deliver planned capital and maintenance programs.

- **Operational Technology (OT) Systems (27%)** – This program is designed to manage the implementation and upgrading of OT infrastructure that underpins operational processes for grid operations within the control centre, trouble dispatch and service restorations. These investments provide grid capabilities for enhanced visibility and automation. Investments within this program include OT systems, ADMS and DERMS upgrades and enhancements, as well as grid modernization.

The facilities management & security assessment considers facilities lifecycles, maintenance, and inspection reports, expected and realized workforce growth and other factors such as the state of contractual arrangements with leased facilities. The Fleet assessment is based on the age and mileage data of vehicle assets as well as mechanical assessments occurring at defined operating thresholds. The Equipment assessment accounts for operational needs, Electric Utility Safety Rules (EUSR), and age and condition data. Refer to Tab 3 - Schedule 1 for additional information on Elexicon's General Plant asset lifecycle management and analytics activities.

Elexicon's forecast General Plant investments over the 2027–2031 period reflect the need to sustain operational capabilities, support workforce growth, modernize technology and maintain the condition of existing facilities. Investment in Ajax and Whitby office renovations, and outdoor storage adjustments at Whitby will enhance the space utilization of Elexicon's existing footprint, precluding the need to construct entirely new facilities during the rate period. Planned investments in fleet expansions include passenger vehicles, trucks, and trailers with electric power takeoff (ePTO) installations, targeting replacements of existing assets based on age, mileage, condition and utilization rates. Elexicon will also invest in IT infrastructure enhancements, data centre upgrades, and endpoint device refreshes, as well as hardware cyber security, OT system upgrades. Overall, these General Plant investments ensure operational continuity, providing sufficient workspace and storage, as well as secure and operationally efficient facilities that are the backbone infrastructure of daily business operations and scaled work program execution.

GLOSSARY

ACA - Asset Condition Assessment

ADMS - Advanced Distribution Management System

AI - Artificial Intelligence

AM - Asset Management

AMI - Advanced Metering Infrastructure

AMDO – Asset Management and Distribution Optimization

APM - Asset Performance Management

APN - Access Point Name

APSE – Asset Planning and System Engineering

APT - Advanced Persistent Threat

BCA - Benefit-Cost Analysis

BCP - Bowmanville Construction Partners

BESS - Battery Energy Storage Systems

BLG - Brooklin Landowners Group

BRT - Bus Rapid Transit

BTFA - Building Transit Faster Act

C&I - Commercial and Industrial

CAIDI - Customer Average Interruption Duration Index

CCA - Customer Connection Agreement

CDD - Cooling Degree Days

CDM - Conservation and Demand Management

CEAP - COVID-19 Energy Assistance Program

CFCI - Communicating Fault Current Indicator

CHI - Customer Hours Interrupted

CHI - Customer Hours Interruption

CHP - Combined Heat and Power

CI - Customer Interruptions or Customers Interrupted

CIA - Connection Impact Assessment

CIS - Customer Information System

CO - Carbon Monoxide

COP - Coefficient of Performance

CS - Criticality Score

DAI - Data Availability Index

DCEP - Durham Community Energy Plan

DER - Distributed Energy Resources

DERCP - Distributed Energy Resources Connection Procedures

DERMS - Distributed Energy Resource Management System

DG - Distributed Generation

DS - Distribution Station

DSC - Distribution System Code

DSO - Distribution System Operator

DSP - Distribution System Plan

DTMP - Durham Transportation Master Plan

EDR - Endpoint Detection and Response

eDSM - Electrical Demand Side Management Framework

EGIA - Electricity and Gas Inspection Act

Elexicon - Elexicon Energy Inc.

EOL - End of Life

ePTO - Electric Power Take-off

ERM - Enterprise Risk Management

ERP - Enterprise Resource Platform

ESB - Enterprise Service Bus

EUI - End-Use Intensity

EV - Electric Vehicle

EWP - Execution Work Program

FCI - Faulted Circuit Indicators

FCI - Faulted Current Interrupters

FESI-7 - Feeders Experiencing More than Seven Sustained Interruptions

FIT - Feed-in-Tarriff

FLISR - Fault Location Isolation and Service Restoration

FTE - Full-Time Equivalent

GIS - Geographic Information Systems

GTA - Greater Toronto Area

HD - Heavy-Duty Vehicle

HDD - Heating Degree Days

HES - Head End System

HI - Health Index

HONI - Hydro One Networks Inc.

HT - Heavy Truck

HW - Hardware

ICE - Internal Combustion Engine

ICM - Incremental Capital Module

IED - Intelligent Electronic Devices

IESO - Independent Electricity System Operator

IR - Infrared

IRRP - Integrated Regional Resource Plan

IS - Impact Score

ISA - In-Service Additions

IT - Information Technology

IT/OT - Information and Operational Technology

KPI - Key Performance Indicator

LDC - Local Distribution Companies

LDV - Light-Duty Vehicle

LIA - Load Impact Assessment

LiDAR – Light Detection and Ranging

LIS - Load Interrupter Switch

LOS - Loss of Supply

LQ - Limiting Quality

LT - Light Truck

LTR - Limited Time Rating

MAPE - Mean Absolute Percentage Error

MC - Measurement Canada

MD - Medium-Duty Vehicle

MED - Major Event Days

MFA - Multi-Factor Authentication

MJU - Multiplex Junction Units

MS - Municipal Station / Substations

MSA - Master Service Agreements

MTO - Ministry of Transportation

MTS - Municipal Transformer Substation

MTSA - Major Transit Station Areas

NELPG - Northeast Pickering Landowners Group

NRCan - Natural Resources Canada

NWS - Non-Wires Solutions

O&M - Operations and Maintenance

OEB - Ontario Energy Board

OLTC - On-Load Tap Charger

OM&A - Operation, Maintenance and Administration

OMS - Outage Management System

ONAF - Oil Natural Air Forced

OPUC - Oshawa Power and Utilities Corporation

OT - Operational Technology

OTC - Offer to Connect

PCIR - Preliminary Consultation Information Requests

PDG - Program Delivery Group

PILC - Paper-Insulated Lead Covered

PPS - Provincial Planning Statement

PS - Probability Score

PSWHA - Public Service Works on Highways Act

PtoK - Peterborough to Kingston

PV - Photovoltaic

PVC - polyvinyl chloride

R^2 - Coefficient of Determination

RBDs - Radial Boom Derricks

REG - Renewable Energy Generation

RIP - Regional Infrastructure Plan

RRR - Reporting and Record Keeping Requirements

RTF - Run to Failure

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

SC - Super-Clean

SCADA - Supervisory Control and Data Acquisition

SG - Synchronous Generator System

SGBM – South Georgian Bay-Muskoka

SO - Scheduled Outages

SOP - Standard Operating Procedure

SQR - Service Quality Requirements

SRR - System Reliability Reporting

SS - Super-Smooth

SSSC - Standard Supply Service Code

STN - Station

SUV - Sport Utility Vehicle

TDR - Time-Domain Reflectometry

The Utility - Elexicon Energy Inc.

THESL - Toronto Hydro-Electric System Limited

TOC - Transit-Oriented Communities

TPM - Trusted Platform Module

TR-XPLE - Tree-Retardant XPLE

TS - Transformer Station

TUL - Typical Useful Life

TWG - Technical Working Group

UAT - User Acceptance Testing

UG - Underground

UPS - Uninterruptible Power Supply

VASH - Vulnerability Assessment and System Hardening

VS - Voltage Sensors

WMA - Weights and Measures Act

WMS - Work Management System

WPF - Worst Performing Feeders

XLPE - Cross-Linked Polyethylene

COORDINATED PLANNING WITH THIRD PARTIES

1. CUSTOMERS

Elexicon engages with its customers on an ongoing basis through a range of channels designed to gather feedback, improve service delivery, and ensure alignment with customer expectations. Engagement activities include an annual customer satisfaction survey targeting residential and small business customers, large customer satisfaction surveys, daily customer service interactions, and community outreach initiatives. Elexicon also maintains an active presence on social media platforms to share updates, including X (formerly Twitter), LinkedIn, and Instagram.

Customer engagement efforts are typically initiated by Elexicon, either through internal staff or, in some cases, through specialized third-party consultants who bring expertise in customer polling and public input gathering. Engagement participants generally represent a cross-section of residential, commercial, and industrial customers, ensuring diverse perspectives are captured. These interactions are facilitated through a combination of Elexicon's website, social media channels, direct outreach, and customer engagement events, allowing the utility to maintain a strong connection with the communities it serves.

2. SUBDIVISION DEVELOPERS AND LARGE LOAD CUSTOMERS

Elexicon consults with developers and large load customers to plan electricity service for large-scale residential, commercial and industrial developments. These consultations ensure that new connections and feeder expansions align with development timelines and regional infrastructure plans. The outcome is documented in scope documents and development plans that outline service requirements, timelines, and capacity needs.

Typically, developers engage with Elexicon several years before electrical service is required. These consultations between Elexicon and real estate developers focus on discussing new connection or expansion requirements for upcoming developments. These meetings include other relevant stakeholders involved in infrastructure planning, such as municipal representatives.

Examples of current, ongoing developer and large load customer consultations include:

- North-East Pickering Developments - Consultations support master planning for a 4,000-acre community in northeast Pickering, including the Seaton Community (a major greenfield residential area that will accommodate approximately 70,000 residents) and the Pickering Innovation Corridor (an 800-acre, high-tech employment zone). The broader Seaton Community is planned to accommodate approximately 70,000 residents and generate 35,000 jobs through a mix of housing and commercial development.

- North Brooklin Residential Developments – Consultations address master planning and servicing strategies for new developments in north Whitby, in addition to ongoing, ad hoc consultations with multiple developers in the area. These discussions are coordinated with the Town of Whitby's infrastructure improvement initiatives, such as the multi-year Columbus Road expansion, to support future population growth and enhance regional connectivity.

Through proactive engagement with developers and municipalities, Elexicon ensures timely delivery of electricity services for new growth areas and plans for future capacity, distribution infrastructure, and service connections. Elexicon provides technical input on available capacity, infrastructure upgrade needs, and expansion planning, recognizing that the pace of development is closely tied to the utility's ability to deliver new service connections and meet growing capacity demands. To ensure alignment with broader regional initiatives, Elexicon also communicates work execution requirements to stakeholders such as municipalities, coordinating efforts around adjacent infrastructure projects like road widening and utility relocations.

These consultations have a significant impact to the DSP as they drive a large portion of work in the Customer & Generation Connections and System Expansion investment programs (Exhibit 2B – Tab 4 – Schedule 3 – Appendix B and C, respectively).

3. MUNICIPALITIES

Elexicon consults with municipalities to discuss issues relevant to the distribution system (e.g. reliability, capacity, ongoing and future infrastructure projects) and to plan and coordinate mandated work such as

new service connections and road relocations. These consultations support prudent planning by ensuring stakeholders are fully informed, and through collaboration to develop alternatives and solutions to complex problems and to identify mandatory service requirements such as road relocations. Elexicon shares key technical information including assessments of its ability to complete new service connections, load forecasts, capacity planning reviews, reliability analyses, and schedules. Based on this material and other inputs, the participants collaborate to develop specific work plans, which document key information including the scope of work, alternatives, recommended solutions, and timelines.

Elexicon initiates these meetings and engages planning departments at each of the 10 lower-tier municipalities it serves (see Exhibit 2B - Tab 1 - Schedule 1 for more information on stakeholders). Other participants include a broad range of stakeholders such as telecommunications utilities and upper-tier municipalities. Meetings are typically held quarterly or semi-annually, depending on the topic and planning cycle.

Municipal consultations inform Elexicon's capital expenditure plan by providing critical inputs, which vary depending on the topic or undertaking. For example, meetings addressing reliability or capacity issues require reliability analyses or load forecasts. This information is used to inform the planning processes and programs, such as Substation Growth (Exhibit 2B – Tab 4 – Schedule 3 – Appendix I).

4. TRANSMITTER

Elexicon coordinates with Hydro One to align planning and operations for the electricity system. These meetings follow a standing agenda, enabling consistent dialogue on key topics such as station outage schedules impacting Elexicon's system, embedded feeder configurations, connection application status updates, and emerging or ongoing supply concerns. The outcome is transparent communication, timely issue resolution, and alignment with Elexicon's commitment to system reliability and collaborative stakeholder management.

To ensure aligned planning and operations, Elexicon maintains structured coordination with Hydro One Networks Inc. (HONI), participating in the Regional Planning Process (detailed in Section 8 of this document), and holds quarterly meetings with Hydro One Transmission. For major projects requiring more

detailed coordination, such as the Belleville DESN 2 Station project, additional meetings are scheduled as needed.

Consultation with Hydro One informs DSP planning by identifying emerging system risks and capacity needs. For example, outage schedules, reliability issues and supply constraints inform investment planning decisions for infrastructure upgrades and reliability projects.

5. METROLINX

Elexicon consults with Metrolinx to understand ongoing or future project work that entails modifications to the electrical distribution system and to plan the associated work that Elexicon will be required to complete. These Metrolinx projects have regional significance and can include road extensions or widening and the construction of new transportation stations or systems. By engaging with Metrolinx, Elexicon can plan to relocate or modify its assets to support initiatives such as rail electrification and new station construction. The outcomes of consultation are documented in work execution plans that define, scope, timelines, responsibilities, and completion requirements.

Metrolinx initiates these consultations and invites stakeholders including municipalities, telecommunications companies, and LDCs such as Elexicon. Elexicon collaborates within these working groups to identify and plan required work. For example, Elexicon is currently engaged in regular consultations with Metrolinx to support rail electrification, for which Elexicon is relocating its assets underground due to configuration of the power distribution system.

Metrolinx projects have a material effect on the DSP because they inform investment requirements in the Externally Initiated Plant Relocation program. For example, Elexicon's asset relocations for Metrolinx's current rail electrification project are planned and prioritized through these consultations. Further details are outlined in the Externally Initiated Plant Relocation Material Narrative presented in Exhibit 2B - Tab 4 - Schedule 3 - Appendix A.

6. OTHER LDCS

Elexicon coordinates with other LDCs to address shared issues and coordination opportunities to improve project efficiency, consistency and realize similar benefits. These consultations focus on capacity

limitations, design challenges, and safe execution of work. The outcome is coordinated plans that support consistent service delivery.

Elexicon and other LDCs, such as Hydro One and Lakeland Power, jointly participate in these consultations. Engagement with other LDCs is generally through established touchpoint meetings, regional planning activities, and project-specific meetings involving multiple parties.

These consultations influence DSP planning by identifying capacity constraints and infrastructure needs, especially where infrastructure is shared or embedded. Elexicon relies on some municipal and transformer station feeders owned by Hydro One Networks Inc., as well as a municipal station feeder owned by Lakeland Power. In other cases, Elexicon has feeders egressing from Hydro One-owned municipal stations, while Hydro One Distribution is linked to feeders owned by Elexicon. Furthermore, there are Elexicon owned municipal stations that are fed from Hydro One Transformer Station feeders. Refer to Exhibit 2B – Tab 3 – Schedule 2 for further details on the specific assets shared with neighbouring LDCs, where Elexicon is either the embedded or host distributor.

The following are specific examples of DSP impacts from engagement with other LDCs:

- Quarterly Touchpoints with Hydro One Distribution provide feeder-level capacity data used in the initial phases of the OEB-led Distribution System Capacity Information Map.
- Fairport Substation Rebuild requires multi-party coordination between Hydro One Distribution, Hydro One Transmission, and Elexicon for shared feeder ownership and design.
- The Belleville DESN 2 project involves collaboration between Hydro One Distribution and Elexicon to drive project completion and resolve design and implementation challenges. Coordination is essential to ensure that sufficient capacity is available, and planning, design, construction, and commissioning are completed safely and efficiently on the infrastructure where Elexicon receives supply from Hydro One Distribution.

7. INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

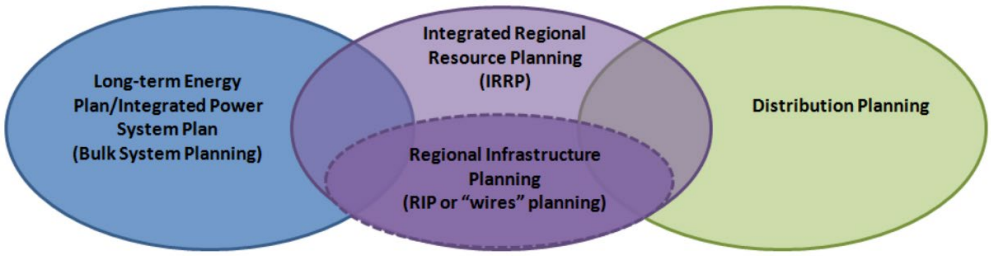
Outside of the Renewable Energy Generation (REG) investment process, regional planning process, and long-term energy supply process, Elexicon does not regularly engage with the IESO.

8. REGIONAL PLANNING PROCESS

Electricity system planning in Ontario is carried out at three levels: bulk system, regional system, and distribution system planning, as shown in Figure 1.

Bulk system planning is led by the IESO and addresses province-wide issues involving the transmission grid, generation sources, and interconnections with neighbouring jurisdictions. Regional planning focuses on supply and reliability needs within specific geographic areas, typically considering transformer stations and transmission supply circuits that serve local load centres. Distribution system planning, conducted by local distribution companies (LDCs), ensures that infrastructure and resources at the local level meet customer demand, while coordinating with Hydro One Transmission and the IESO where transmission supply facilities are involved.

Figure 1: Levels of Electricity System Planning[1]



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

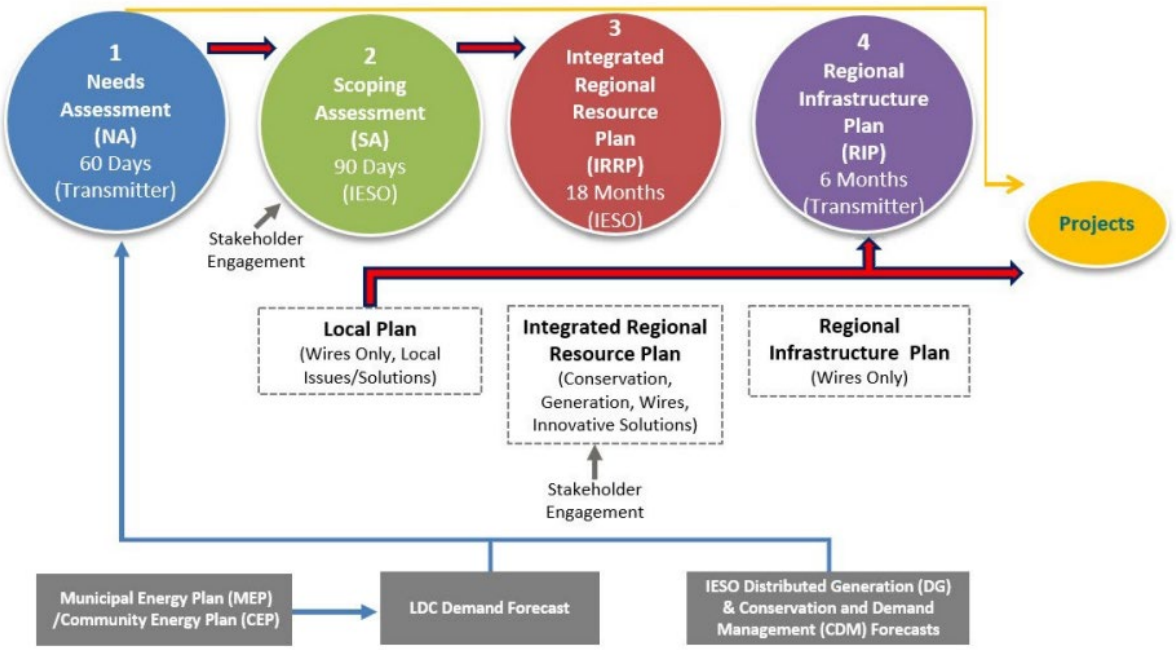
[1] Ontario Energy Board, "Planning Process Working Group Report to the Board", (May 17, 2013)

To strengthen coordination at the regional level, the OEB established a formal Regional Planning Process in 2013, designed to provide transparent, cost-effective planning of electrical infrastructure. This is a cyclical, multi-phase process that includes:

- Needs Assessment
- Scoping Assessment
- Integrated Regional Resource Plan (IRRP)
- Regional Infrastructure Plan (RIP)

Figure 2 shows the flow chart of the Regional Planning Process.

Figure 2: Regional Planning Process Flowchart[2]



Needs Assessment

[2] Hydro One Networks Inc., "Needs Assessment Report – Greater Toronto Area East Report", (December 11, 2024)

Purpose: The Needs Assessment phase begins the process, and is led by the lead transmitter, in this case, Hydro One Transmission. It identifies new system needs or reaffirms previously identified needs through technical assessments and collaborative discussions on system capacity, reliability, operations, and aging infrastructure. Participants review options, develop preferred plans, and determine which issues require further analysis or broader regional coordination.

Role of Elexicon: As a participating LDC, Elexicon provides data and insights to support the assessment of system capacity, reliability, operations, and asset condition. Elexicon also offers perspectives on outcomes, discusses potential solutions, and recommends further coordination where needed.

Key Inputs: Elexicon provides transformer station (TS) level load forecasts, which are combined with IESO conservation demand management (CDM) and distributed generation (DG) projections to create transmission station-level net load forecasts. LDCs also supply information on system reliability, operational issues, and high voltage transmission equipment needing replacement or refurbishment.

Final Deliverables: This phase produces a Needs Assessment report summarizing background, methodology, and identified needs, along with recommendations for the optimal planning approach (e.g., RIP, IRRP, or Local Plan).

Scope Assessment

If the Study Team determines that further planning is necessary to evaluate specific system needs within Elexicon Energy's service area, the IESO initiates the Scoping Assessment phase.

Purpose: The Scoping Assessment confirms the nature and scope of needs identified in the Needs Assessment and recommends the appropriate planning path – either a Regional Infrastructure Plan (RIP) for wires solutions or an Integrated Regional Resource Plan (IRRP) for broader options.

Role of Elexicon: As a participating LDC, Elexicon collaborates closely with the IESO, Hydro One and other LDCs, providing technical data, operational insights, and perspectives to support the evaluation of alternatives and assessment outcomes.

Key Inputs: Inputs include the needs identified in the Needs Assessment phase, operational and reliability data, and information on potential non-wires solutions (CDM, DG, energy storage) relevant to addressing those needs.

Final Deliverables: The Scoping Assessment phase results in a report summarizing assessed needs and recommendations on which solutions should advance to the IRRP for integrated approaches (led by IESO) or the RIP for traditional transmission solutions (led by Hydro One).

Integrated Regional Resource Plan (IRRP)

Purpose: The IRRP phase evaluates and develops integrated solutions to address regional electricity needs identified in earlier phases. It considers both wires and non-wires alternatives — including CDM, DG, energy storage, and other innovative options — to provide cost-effective, reliable, and sustainable solutions.

Role of Elexicon: As a participating LDC, Elexicon provides technical data, operational insights, and regional perspectives. Elexicon collaborates with participants to assess alternatives, evaluate feasibility, and recommend integrated solutions that balance reliability, cost, and sustainability.

Key Inputs: Key inputs for the IRRP phase include updated transformer station and feeder-level load forecasts, IESO CDM and DG projections, transmission and distribution asset performance and condition data, evaluation of potential non-wires alternatives such as CDM programs, DG, or energy storage, and regional reliability and operational metrics.

Final Deliverables: The IRRP report summarizes regional needs, evaluates alternative integrated solutions, and provides recommended plans combining wires and non-wires resources, with guidance for coordinated implementation.

Regional Infrastructure Plan (RIP)

Purpose: The RIP phase summarizes regional needs and develops associated wires plans, including any new needs identified since the start of the planning cycle. It identifies coordinated transmission and/or distribution investments required to meet infrastructure needs.

Role of Elexicon: Elexicon collaborates with participants to finalize needs, develop alternatives, and provide recommendations. Elexicon shares new information, offers perspectives on alternatives, and helps identify emerging needs.

Key Inputs: Key inputs are similar to those in the Needs Assessment phase, including load forecasts and system data, with updates provided as needed to reflect new or evolving needs.

Final Deliverables: This phase produces an RIP report summarizing the final set of needs, alternative wires plans, and recommendations.

These Regional Planning phases are led jointly by the IESO, Hydro One, and impacted LDCs, with input from stakeholders, and they ensure that regional supply needs are clearly identified and that cost-effective solutions are developed. Regional planning often intersects with distribution planning at key supply points, such as transformer stations, and in cases where local distribution solutions can address broader regional needs (e.g., load transfers between stations).

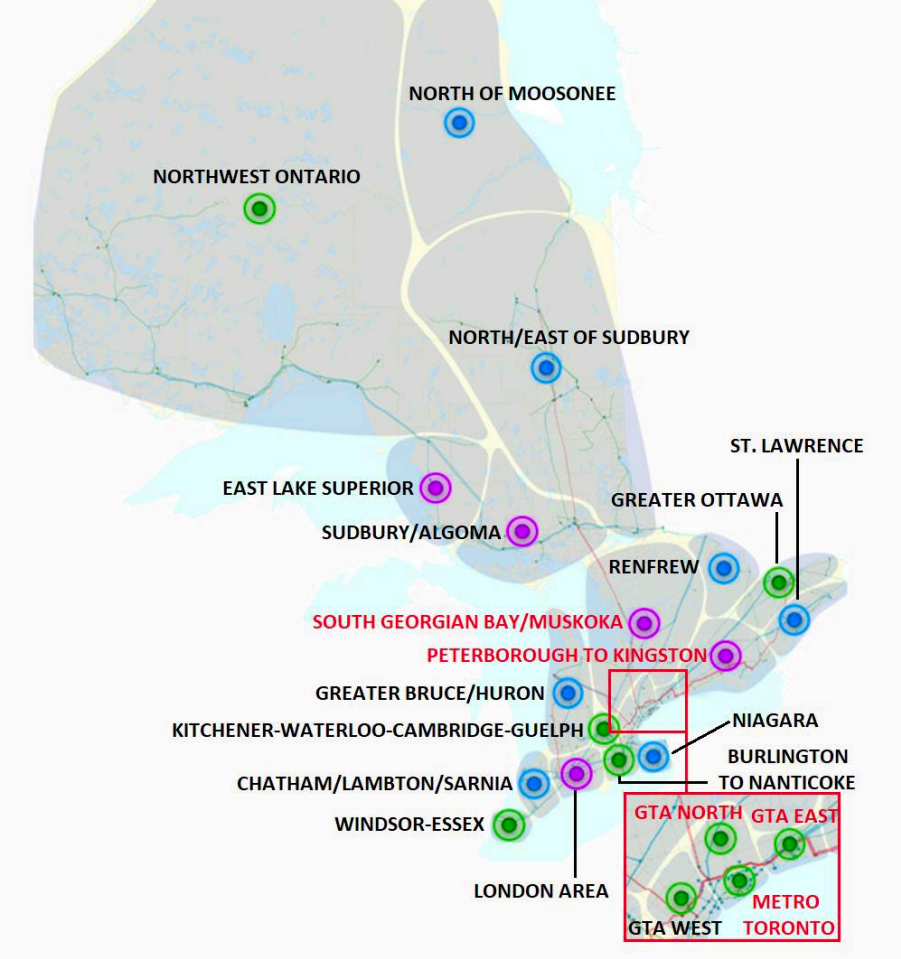
Given its widespread and non-contiguous service territory, Elexicon participates in five regional planning zones:

- GTA East
- GTA North
- Peterborough to Kingston (P-to-K)
- Metro Toronto
- South Georgian Bay/Muskoka

Within these zones, Elexicon works closely with the IESO, Hydro One, neighbouring distributors, developers, and other stakeholders through joint committees and coordinated studies. This collaboration ensures that regional considerations are effectively integrated into Elexicon's distribution system planning,

supports the identification of transmission supply needs at its stations, and promotes efficient investment in both wires and non-wires solutions.

Figure 3: Overview of Regional Planning Zones in Ontario[3]



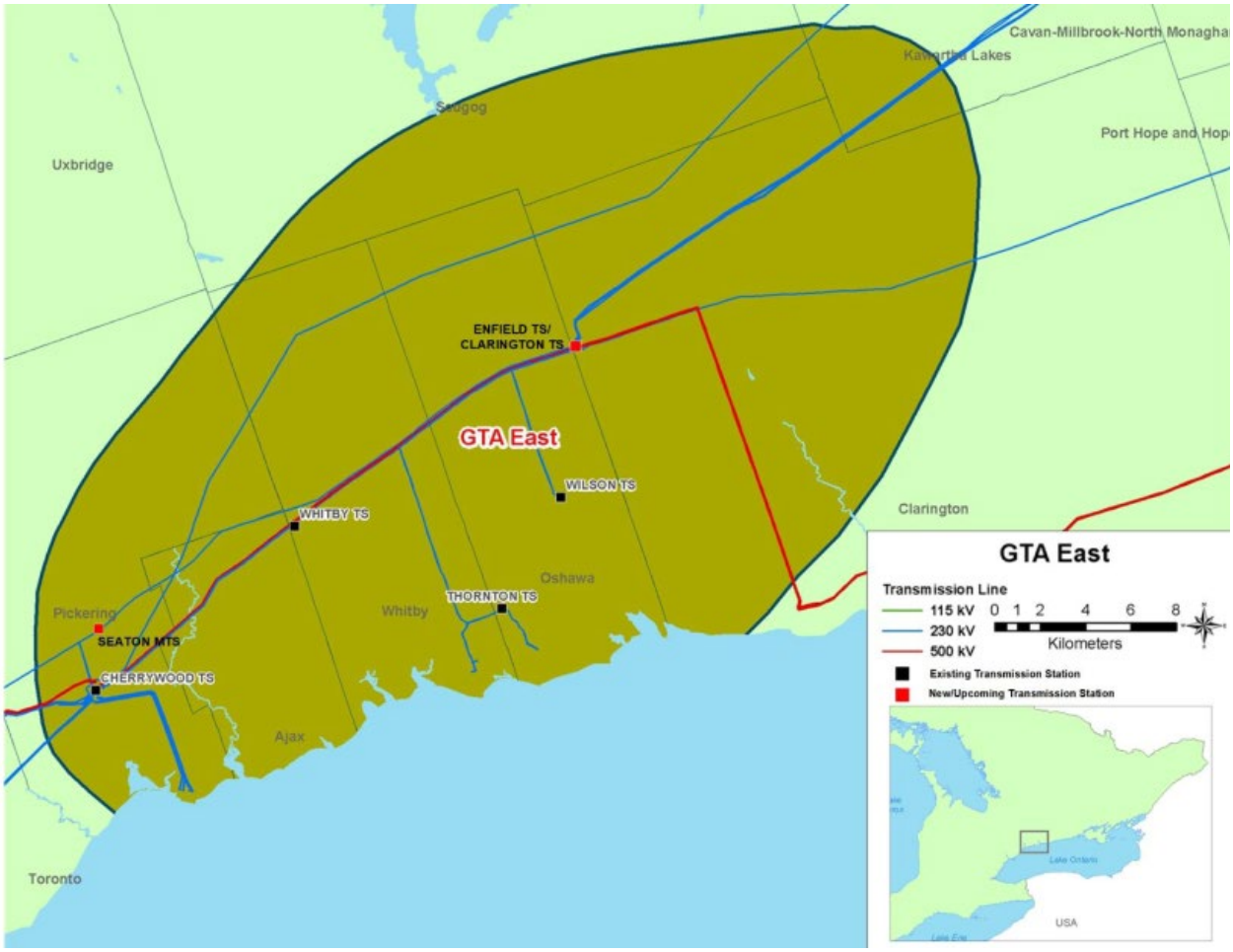
8.1 GTA East

Figure 4 below provides an overview of the GTA East regional planning area. Elexicon's service territory in the GTA East Region is supplied directly by Cherrywood TS, Seaton MTS (Elexicon-owned), Thornton TS,

[3] EB-2021-0015, Section 5.2.2, page 37

and Whitby TS, and is also served as an embedded customer on Hydro One Distribution feeders supplied from Enfield TS and Wilson TS.

Figure 4: Map of GTA East Regional Planning Area[4]



Elexicon has actively participated in the Technical Working Group (TWG) together with the following participants:

- IESO

[4] Hydro One Networks Inc., "Needs Assessment Report – Greater Toronto Area East Report", (December 11, 2024)

- Hydro One Networks Inc. (Transmission and Distribution),
- Oshawa Power and Utilities Corporation (OPUC)

Through this participation, Elexicon provided load forecasts, connection data, and system capability information to facilitate the coordination and alignment of regional and local plans.

The Needs Assessment for the GTA East Region was initiated by Hydro One in August 2024 and completed in December 2024 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix A). The Needs Assessment identified several regional system needs, including station capacity constraints and requirements for transmission reinforcement, and clarified which needs should be addressed through regional coordination versus local planning.

As part of the Needs Assessment, Elexicon submitted a 10-year summer and winter load forecast (2024–2033) for the transformer stations (TS) and respective feeders serving its territory.

As outlined in the Needs Assessment, the needs impacting Elexicon's 2027-2031 rate period are shown in Table 1 below:

Table 1: Needs impacting 2027-2031 rate period

Need Type	Specific Need / Asset	Recommendation	Timing
Station Capacity Needs	Whitby TS T1/T2	Station overload, with a proposed plan for a new TS in the North Whitby area, the GTA East TS.	2032[5]
	Thornton TS T3/T4	Station overload[6]- Plan to cap load at Thornton, and future growth will be served by the new North Whitby TS, the GTA East TS	2031

[5] GTA East TS planned in service date is 2031, prior to exceeding capacity needs in 2032.
[6] Thornton station capacity expected to be reached by 2031 (winter) and 2033 (summer)

Following the Needs Assessment, Hydro One completed the Scoping Assessment in April 2025 (Exhibit 2B – Tab 2 – Schedule 1 - Appendix B). The Scoping Assessment determined the planning approach for each identified need, specifying which issues should proceed to the IRRP stage versus local planning. It also recommended that a range of alternatives, including wires and non-wires solutions, be explored in a coordinated manner by the TWG. As a TWG member, Elexicon ensured its customers' projected growth was incorporated into the planning framework.

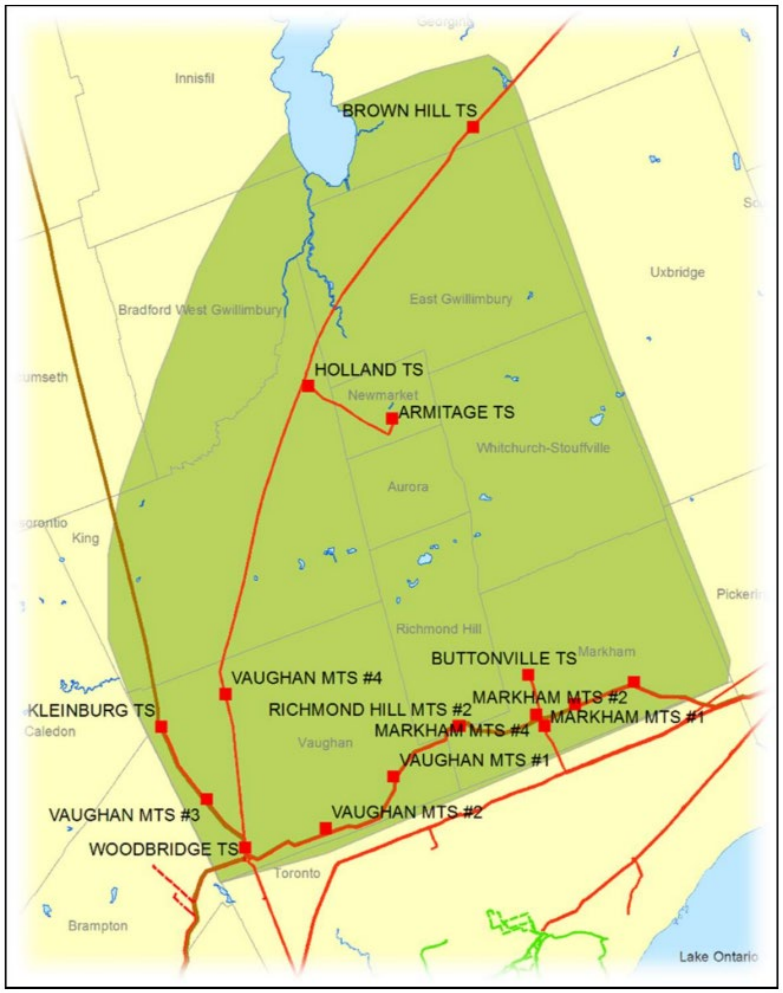
Planning for a new GTA East Transformer Station (TS) in the North Whitby / North Pickering area is underway to address capacity constraints at Whitby TS and Thornton TS. Elexicon is currently in the early planning stages for the project, focusing on land acquisition, environmental assessments and transmission planning with Hydro One. The new station is part of the 2027–2031 investment period, with a planned in-service date of 2031. Further details are outlined in the Substation Growth Material Narrative and GTA East business case, presented in Exhibit 2B - Tab 4 - Schedule 3 - Appendix I, and Appendix I-1 respectively.

Elexicon and Hydro One Transmission have presented their findings to the TWG as part of the Needs Assessment, and the IRRP will build on this analysis by evaluating options and assessing system impacts. According to the IESO's Regional Planning Dashboard, the updated GTA East IRRP is scheduled for publication by September 2026, at which time the final recommendations, implementation timelines, and coordinated solutions will be made available.

8.2 GTA North

Figure 5 below provides an overview of the GTA North Regional Planning area. Within this region, Elexicon Energy's service territory is entirely embedded on Hydro One distribution feeders supplied from Armitage TS.

Figure 5: Map of GTA North Regional Planning Area[7]



The third cycle of regional planning for the GTA North region was initiated in March 2023, with the Needs Assessment completed in July 2023 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix C). The Scoping Assessment was completed in October 2023 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix D). The updated GTA North IRRP was just recently published on October 10, 2025 (see Exhibit 2B – Tab 2 – Schedule

[7] Hydro One Networks Inc., "Needs Assessment Report – Greater Toronto Area North Region", (July 14, 2023)

1 - Appendix E), with the RIP, the final step of the Regional Planning cycle, expected to be completed by May 2026.

Elexicon has actively participated in the TWG together with the following participants:

- IESO
- Hydro One Networks Inc. (Transmission and Distribution),
- Alectra Utilities Corporation
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited (THESL)

Through its participation in the GTA North Regional Planning process, Elexicon provided load forecasts for all supply stations in the region, along with connection data, system capability information, and details on capacity and reliability needs, operational issues, and major transmission equipment requiring replacement. Elexicon also outlined planned transmission and distribution investments relevant to the process to support coordination and alignment of regional and local plans.

No needs within Elexicon's service territory were identified that require further regional coordination impacting the 2027–2031 rate period. However, Elexicon's participation ensured its future planning interests are appropriately considered. Elexicon participated to ensure its future planning interests are considered.

8.3 Metro Toronto

Figure 6 below provides an overview of the Metro Toronto Regional Planning area. Elexicon Energy's service territory is supplied from Malvern TS and Sheppard TS as an embedded customer on Hydro One's feeders.

Figure 6: Map of Toronto Regional Planning Area[8]



The third cycle of regional planning for the Toronto region was initiated in August 2022, with the Needs Assessment completed on December 19, 2022 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix F). The Scoping Assessment was completed in March 2023. The updated Toronto Region IRRP was published on October 31, 2025, with the RIP, the final stage of the Regional Planning cycle, kicking off in November 2025.

Elexicon has actively participated in the TWG together with the following participants:

[8] Hydro One Networks Inc., "Needs Assessment Report – Toronto Region", (December 19, 2022)

- IESO
- Hydro One Networks Inc. (Transmission and Distribution)
- Alectra Utilities Corporation
- Toronto Hydro-Electric System Limited (THESL)

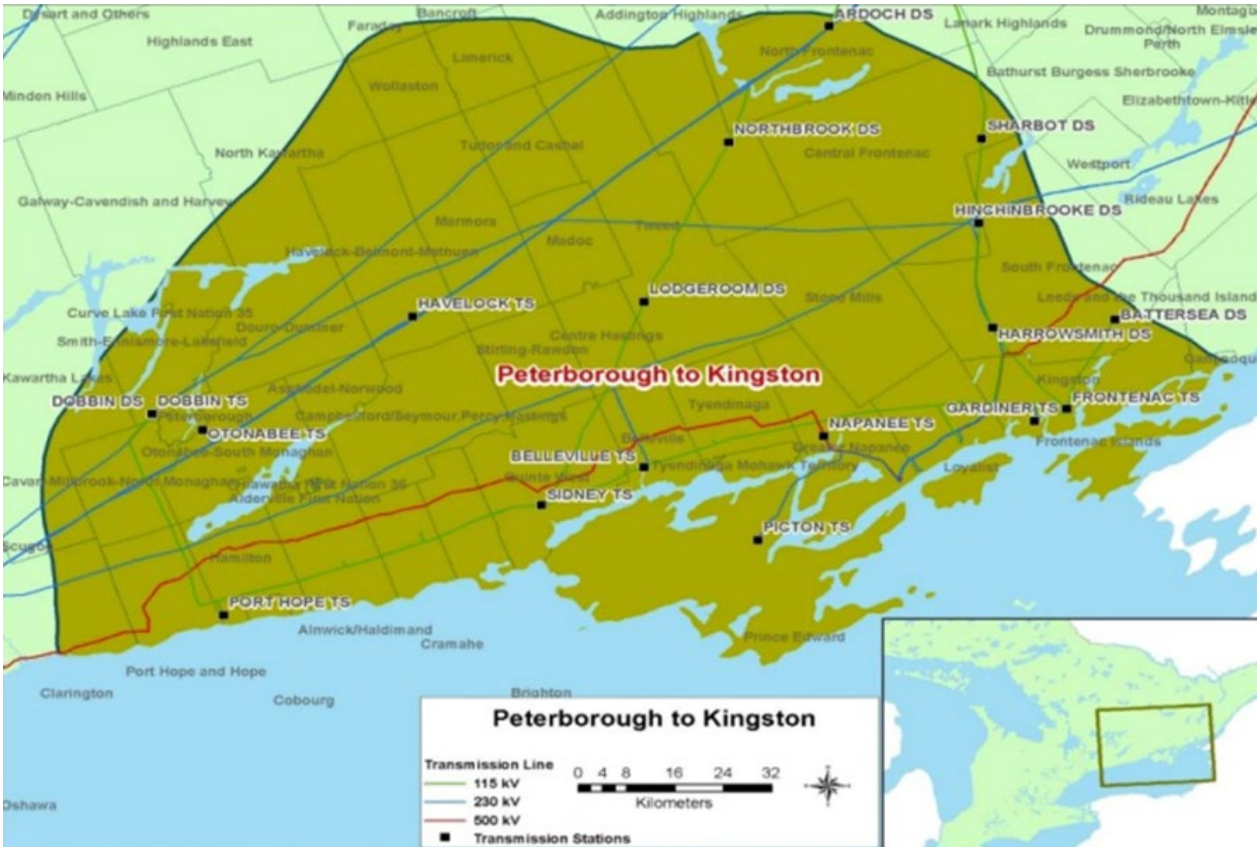
Through this participation, Elexicon provided local load forecasts, connection data, and system capability information to facilitate the coordination and alignment of regional and local plans.

No needs within Elexicon Energy's service territory were identified requiring further regional coordination impacting the rate period 2027-2031. Elexicon participated to ensure its future planning interests are considered.

8.4 Peterborough to Kingston (P-to-K)

Figure 7 below provides an overview of the P-to-K Regional Planning area. Elexicon Energy's service territory in P-to-K region is directly supplied from Belleville TS and is also served as an embedded customer on Hydro One Distribution feeders supplied from Port Hope TS.

Figure 7: Map of Peterborough to Kingston Regional Planning Area[9]



Elexicon has actively participated in the TWG together with the following participants:

- IESO
- Hydro One Networks Inc. (Transmission and Distribution),
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

[9] Hydro One Networks Inc., "Needs Assessment Report – Peterborough to Kingston Region", (December 20, 2024)

Through this participation, Elexicon provided local load forecasts, connection data, and system capability information to facilitate the coordination and alignment of regional and local plans.

The Needs Assessment for the P-to-K Region was completed by Hydro One in December 2024, marking the start of the third regional planning cycle (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix G). The Needs Assessment identified several regional electricity system needs and reaffirmed previously recognized needs, including emerging station capacity requirements, end-of-life equipment replacements, and localized distribution constraints. The need identified in the Needs Assessment directly impacting Elexicon is shown below in Table 2

Table 2: Needs impacting Elexicon identified in Needs Assessment

Need Type	Specific Need / Asset	Recommendation	Timing
Station Capacity Needs	Belleville TS	Comprehensive assessment required in next planning phases, including a bulk planning study.	Belleville DESN2 in service by end of 2026. By 2028–2031, voltage constraints for H23B contingency may cause undervoltage at DESN2, requiring partial loss of load.

Following the Needs Assessment, Hydro One completed the Scoping Assessment for the P-2-K Region in April 2025 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix H). The Scoping Assessment reviewed the Needs Assessment findings to determine the appropriate planning approach for each identified need, specifying which issues should proceed to the Integrated Regional Resource Plan (IRRP) stage and which should be addressed through local planning.

Planning and construction work on the new Belleville DESN 2 project, which will include two 75/100/125 MVA transformers at the existing Belleville TS site, is underway and scheduled for completion in 2026. Transmission voltage issues under contingency conditions are also being assessed through the Eastern

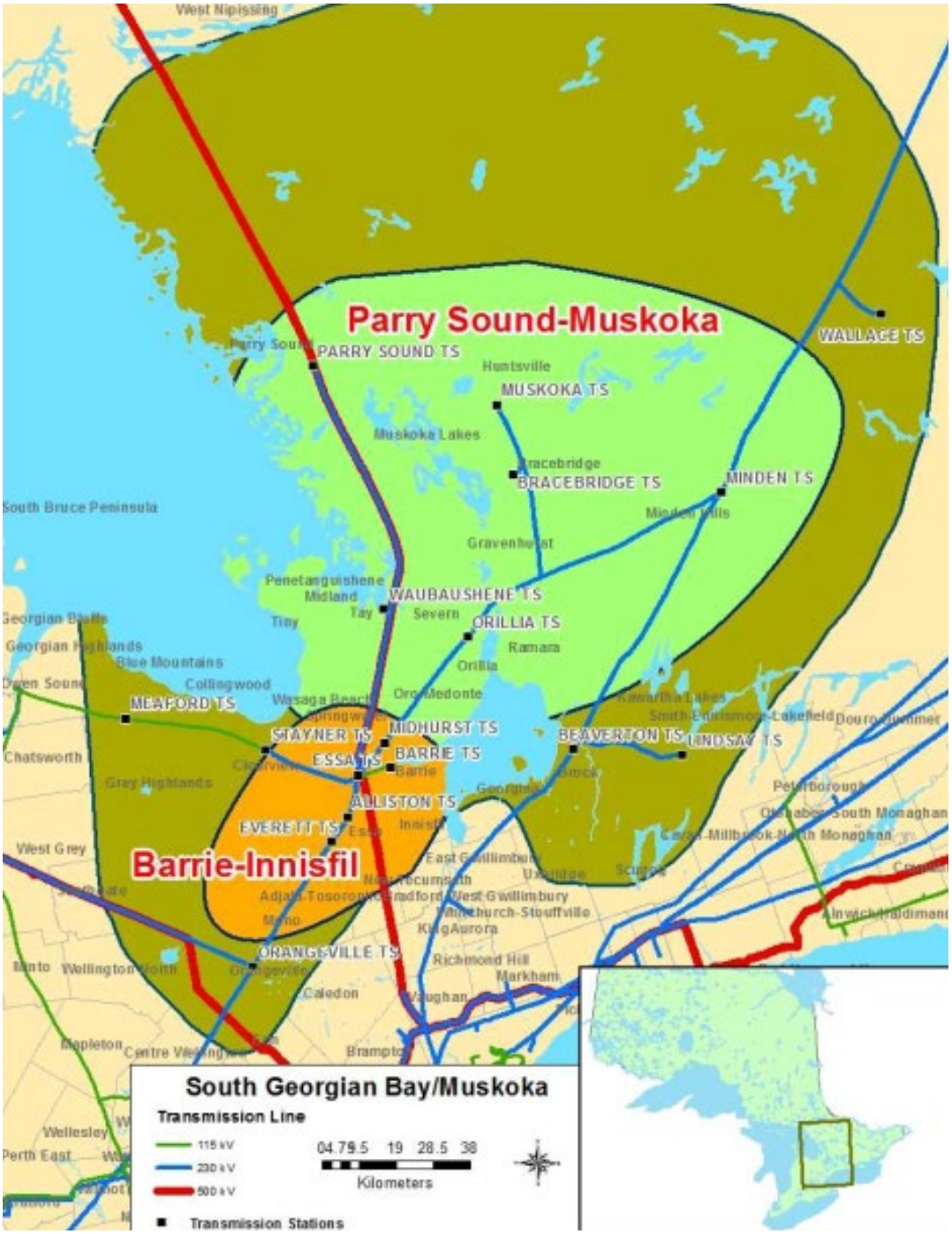
Ontario Bulk Planning Study. Elexicon is actively participating in the TWG discussions on these issues; At this stage, no further actions for Elexicon have been identified.

The IRRP will build on this analysis by assessing options and evaluating system impacts. According to the IESO's Regional Planning Dashboard, the updated P-to-K IRRP is scheduled for publication by December 2026, at which time the final recommendations, implementation timelines, and coordinated solutions will be made available.

8.5 South Georgian Bay-Muskoka

Figure 8 below provides an overview of the South Georgian Bay-Muskoka Regional Planning area. Elexicon Energy's service territory is supplied from Beaverton TS and Bracebridge TS as an embedded customer on Hydro One Dx feeders.

Figure 8: Map of South Georgian Bay – Muskoka Regional Planning Area[10]



The third cycle of regional planning for the South Georgian Bay-Muskoka region was initiated in April 2025, with the Needs Assessment completed in August 2025 (see Exhibit 2B – Tab 2 – Schedule 1 - Appendix I). The IESO is expected to complete the Scoping Assessment in November, after which the IRRP process will commence. As the region is still at the Scoping Assessment stage, timelines for the release of the IRRP report are not yet available.

Elexicon has actively participated in the TWG together with the following participants:

- IESO
- Hydro One Networks Inc. (Transmission and Distribution)
- Alectra Utilities Corporation
- InnPower
- Orangeville Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc
- NT Power Distribution
- Wasaga Distribution Inc.

Through this participation, Elexicon provided local load forecasts, connection data, and system capability information to facilitate the coordination and alignment of regional and local plans.

Beyond this, the recently completed regional planning cycle did not identify any additional needs within Elexicon Energy's service territory requiring further regional coordination impacting the rate period 2027-2031. Elexicon will continue to participate in the Scoping Assessment and IRRP coordination process to ensure its future planning interests are considered.

[10] Hydro One Networks Inc., "Needs Assessment Report – South Georgian Bay – Muskoka", (August 27, 2025)

8.6 Conclusion

The regional planning processes reviewed above highlight where identified system needs intersect with Elexicon's service territory. Table 3 summarizes the specific investment needs that directly impact Elexicon during the 2027–2031 rate period, along with their associated timing and related narrative references.

Table 3: Investment needs impacting Elexicon during the 2027-2031 rate period (with related narratives)

Regional Zone	Elexicon Investment Need 2027-2031	In-Service Date	Related Material Narrative
GTA East	Whitby TS: Address station overload through a new GTA East TS	2031	S1 – Substation Growth Narrative
GTA North	No need identified	Not applicable	Not applicable
Metro Toronto	No need identified	Not applicable	Not applicable
Peterborough to Kingston	No need identified	Not applicable[11]	Not applicable
South Georgian Bay – Muskoka	No need identified	Not applicable	Not applicable

Through its active participation in regional planning, Elexicon is ensuring that local growth requirements and system needs are reflected in broader planning outcomes, enabling timely and coordinated investment decisions.

9. TELECOMMUNICATION ENTITIES

Elexicon Energy ensures effective coordination with telecommunications entities operating within its service territory through municipal planning and permitting processes, as well as a third-party attachment consultation process. These mechanisms allow for timely and efficient information exchange regarding infrastructure planning and project execution.

[11] The Belleville DESN 2 investment was captured in Elexicon's 2026 ICM Application: EB-2025-0046

Through municipal permitting processes, Elexicon circulates plans to the relevant municipalities to obtain the necessary permits for its planned work. This process facilitates coordination with telecommunication companies and large developers by enabling them to review and comment on Elexicon's infrastructure plans. In new subdivision developments, the developer typically manages the coordination process through a Composite Utility Plan, using a standard joint-use trench configuration that includes space for telecommunication infrastructure. This practice is consistent across Elexicon's service territory.

Elexicon also maintains a formal consultation process for telecoms seeking to attach infrastructure to its assets. Telecoms must apply and coordinate with Elexicon to obtain approval for such attachments. In areas without existing telecommunications infrastructure, Elexicon's standards provides accommodations for future telecommunications attachments, allowing telecommunications service providers to submit an application to Elexicon once the poles are in place.

For externally initiated or capital replacement projects, Elexicon's design technicians notify impacted third parties when plant relocation is required. Significant relocations may involve the preparation of detailed relocation drawings, which are reviewed and approved by Elexicon's technical team. In other cases, infrastructure is transferred on a like-for-like basis. Coordination with existing third-party telecoms is part of Elexicon's design technician responsibilities, ensuring provisions are made for third-party attachments where necessary. Elexicon also maintains design standards for joint-use trenching, which are applied as required to facilitate joint installations with telecommunications providers.

These planning and coordination practices ensure that Elexicon maintains strong working relationships with telecommunications entities, minimizes infrastructure conflicts, and promotes efficient project execution throughout its service territory.

Table 4: Summary of Consultations

Date of Consultation	Consultation Overview	Participants
Bi-Weekly	Regular biweekly meetings with major telecommunications providers and the Region of Durham to coordinate on operational and planning matters. Meetings cover updates on ongoing items and the introduction of new issues for discussion.	• Telecom Companies • Region of Durham

By incorporating feedback from these consultations, Elexicon has ensured that its capital investments are properly coordinated with telecommunications entities, minimizing potential conflicts, and supporting the provision of reliable telecommunications services within its service area.

10. RENEWABLE ENERGY GENERATION (REG)

Elexicon currently has no significant investments planned within Renewal Energy Generation (REG) over the 2027-2031 period.

10.1 IESO Comment Letter

As noted above, given that Elexicon does not have any significant investments planned within Renewal Energy Generation over the 2027–2031 period, this section is not applicable.

11. LIST OF ATTACHMENTS:

- Appendix A: GTA East – Needs Assessment
- Appendix B: GTA East – Scoping Assessment
- Appendix C: GTA North – Needs Assessment
- Appendix D: GTA North – Scoping Assessment
- Appendix E: GTA North – Integrated Regional Resource Plan
- Appendix F: Metro Toronto – Needs Assessment
- Appendix G: Peterborough to Kingston – Needs Assessment
- Appendix H: Peterborough to Kingston – Scoping Assessment

- Appendix I: South Georgian Bay-Muskoka – Needs Assessment

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX A
GTA EAST – NEEDS ASSESSMENT



NEEDS ASSESSMENT REPORT

Greater Toronto Area East

December 11, 2024

Needs Assessment Report

Greater Toronto Area (GTA) East Region

December 11, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

GTA East Technical Working Group

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Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Toronto Area East and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the Needs Assessment phase and b) require further assessment and regional coordination. The results reported in this Need Assessment are based on the input and information provided by the Technical Working Group (the "TWG") for this region at the time. Updates may be made based on best available information throughout the planning process.

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	Greater Toronto Area East (GTA East) Region (the "Region")
LEAD	Hydro One Networks Inc. ("Hydro One")
START DATE: August 13, 2024	**END DATE:** December 11, 2024

1. INTRODUCTION

The second Regional Planning cycle for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") report (RIP Report). This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,

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

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered for the GTA East Region on August 13th , 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA East Region NA includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),

b) Identify any new needs resulting from this assessment,

c) Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The 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.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

5. INPUTS/DATA

The TWG comprises of representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the Region regarding capacity needs, reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecast.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The need assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy
b) System reliability needs and operational concerns
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"

d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle

The following needs discussed in the GTA East Region second cycle RIP have been completed:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed in service in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.

The following needs and projects discussed in the GTA East second cycle RIP are currently underway:

- Cherrywood TS 230kV Breaker Replacement (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respetively.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Wilson TS - T3/T4 Replacement

b) Station Capacity

- Whitby TS T1/T2 DESN (44kV)
- Thornton TS T3/T4 DESN
- Wilson TS T7/T8 DESN
- Wilson TS T3/T4 DESN

c) Transmission Line Capacity

- No new transmission Line Capacity need identified

d) System Reliability, Operation and Load Restoration

- T23C/T29C corridor may exceed load security limit of 600MW in 2032 if all forecasted loads at the current stations are supplied from original connection points

e) Transmission System Reinforcement

- Major transmission expansion in Oshawa-Clarington sub-region area will be needed to accommodate increasing new large load connection requests. Existing 230kV transmission facilities do not have sufficient capacity to supply the new demand.

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 investments.

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to need dates and new station capacity needs. These needs will be assessed again during the next phases of this Regional Planning cycle.

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033

* If the transformers are replaced with higher LTR rating units as planned.

** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS

9. RECOMMENDATIONS

The TWG recommendations are as follows:

I. Needs that require further assessment and regional coordination

These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

a) Integrated Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address T23C/T29C corridor load security issue
b) Station capacity need at Thornton TS in Oshawa area due to load growth
c) Station capacity need at Wilson TS T7/T8 in Oshawa area due to load growth
d) Station capacity need at Wilson TS T3/T4 in Oshawa area due to load growth

II. Needs that do not require further regional coordination

These needs can be addressed by a straightforward transmission and/or distribution wires solution, or they are local in nature and do not have a regional impact. They either do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

a) Cherrywood TS 230kV Breaker Replacement
b) Wilson TS - T3/T4 Transformer Replacement
c) Station capacity need at Whitby TS T1/T2 (44kV) in North Whitby area due to load growth

List of LDC(s) to be involved in further regional planning phases:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

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1. Introduction

The second cycle of the Regional Planning process for the GTA East Region was completed in February 2020 with the publication of the Regional Infrastructure Plan ("RIP") Report [1] - (RIP link). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the GTA East Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. The flow chart of the Regional Planning Process is shown in Figure 1 below.

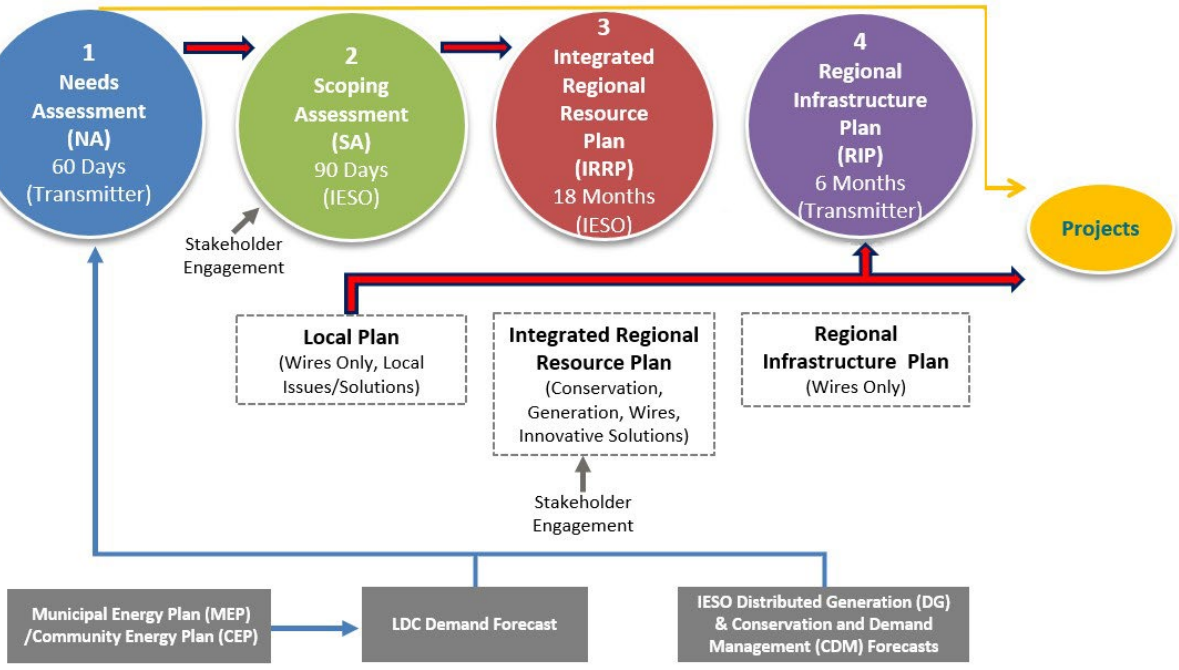


Figure 1: Regional Planning Process

This report was prepared by the GTA East Technical Working Group("TWG"), led by Hydro One Networks Inc. 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"). Participants of the TWG are listed below in Table 1.

Table 1: GTA East Region TWG Participants

No.	Name of TWG Participants
1	Hydro One Networks Inc. (Transmission) - (Lead Transmitter)
2	Independent Electricity System Operator
3	Elexicon Energy Inc.
4	Oshawa PUC Networks Inc.
5	Hydro One Networks Inc. (Distribution)

2. Regional Issue/Trigger

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the third Regional Planning cycle was triggered for the GTA East Region.

3. Scope of Needs Assessment

The scope of this NA covers the GTA East region and includes:

- Review and update needs and plans identified in the previous cycle RIP,
- Identify any new needs resulting from this assessment,
- Recommend which needs require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan, and
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDCs to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

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

The planning horizon for this NA assessment is 10 years.

4. Regional Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area.

The geographical boundaries of the Region are shown in Figure 2.

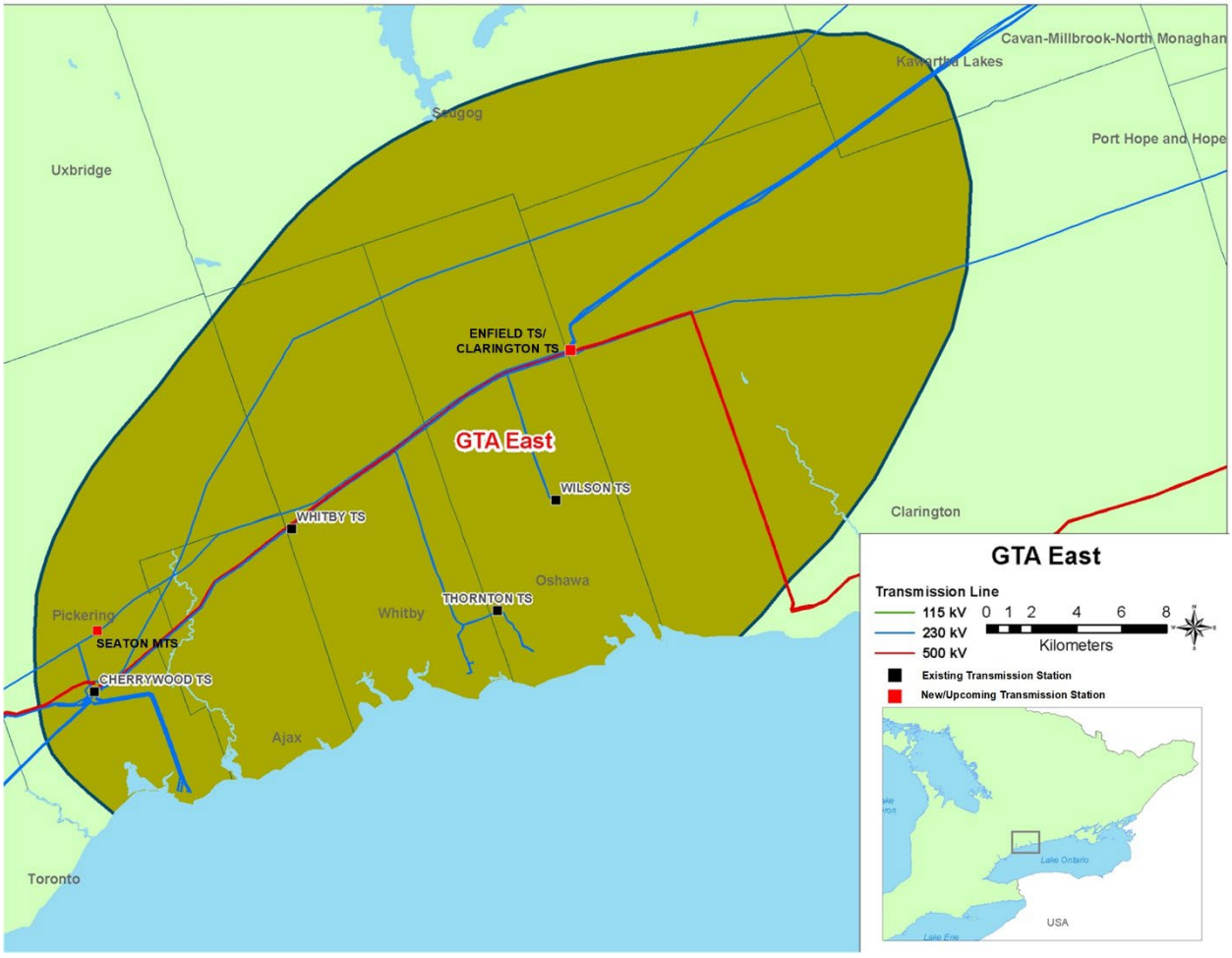


Figure 2: Map of GTA East Regional Planning Area

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington Transformer Station (TS) and six 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are six step-down transformer stations (five Hydro One owned and one LDC owned), and three direct transmission connected load customers. Metrolinx Traction Power Substation (TPSS) is proposed to be in service in 2029. The distribution system is at two voltage levels, 44kV and 27.6kV.

The Local Distribution Customers (LDC) in the Region include Elexicon Energy Inc., Oshawa PUC Networks Inc. and Hydro One Networks Inc. (Distribution). An electrical single line diagram for the GTA East Region facilities is shown in Figure 3.

The circuits and stations of the area are summarized in Table 2 below:

Table 2: Transmission Station and Circuits in the GTA East Region

230kV circuits	Transformer Stations	Generation Stations
T23C T24C T26C T28C T29C C10A	Cherrywood TS[1] Seaton MTS Thornton TS Whitby TS Wilson TS Enfield TS CTS A CTS B CTS C Metrolinx TPSS (in-service 2029)	CGS D, 60MW gas-fired cogeneration Pickering Nuclear Generating Station (NGS), approximately 3000 MW

1: 500kV Stations with Autotransformers installed

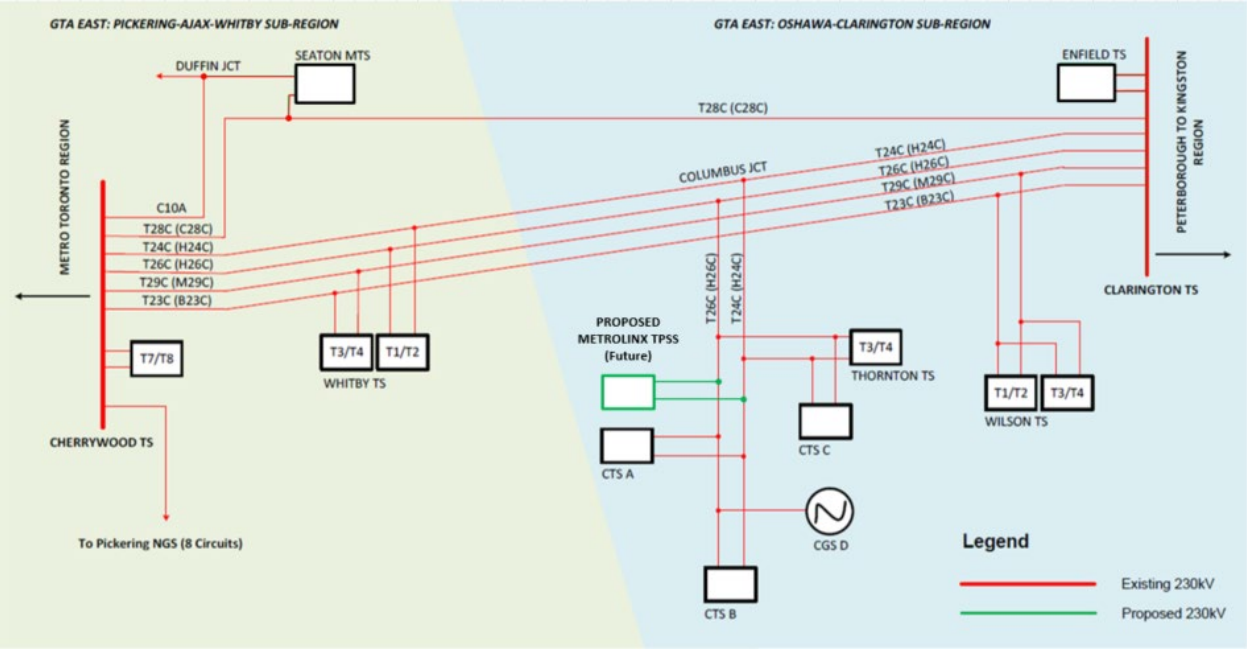


Figure 3: GTA East Transmission Single Line Diagram

5. Inputs and Data

TWG participants, including representatives from LDCs, IESO, and Hydro One provided input for the GTA East NA. 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 Oct. 2022 [2]. 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 regional planning 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). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the followings:

- GTA East 10-year summer and winter load forecast for all supply stations inclusive of the inputs provided by the municipalities listed in Appendix E
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement or refurbishment
- Planned transmission and distribution investments that are relevant to Regional Planning for the GTA East
- Captured 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.

6. Assessment Methodology

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy
- System reliability and operational considerations
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"
- Load forecast data requested from industrial customers in the region
- Summer and Winter peak load conditions. Three load forecasts were developed for Summer and Winter respectively, i.e. normal growth scenario, high and low growth scenario. The high and low growth load forecasts are developed to conduct a sensitivity analysis to cover unforeseen developments such as fuel switching, government policies, higher than expected EV charging trend during peak load conditions, etc.

The following assumptions are made in this report:

- The study period for this Needs Assessment is 2024-2033.
- The Region is summer peaking, but will be transitioning to winter peaking for most of transformer stations in this study period, so this assessment is based on both summer and winter peak loads.
- Line capacity 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 without low-voltage capacitor banks and 95% lagging power factor for stations with low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One Summer/Winter 10-Day Limited Time Rating (LTR) at 35 and 10 degree celcius respectively for Summer/Winter of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC)[3] .

6.2 Information Gathering Process

6.2.1 Load forecast

The LDCs provided their summer and winter load forecast for all the stations supplying their loads in the GTA East region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Region. The net extreme summer weather load

forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer weather corrected net load forecast for the individual stations in the Region is given in Appendix A.

6.2.2 Sensitivity analysis

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3 Asset renewal needs for major HV equipment

A list is generated for major HV transmission equipment planned or identified to be replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4 System reliability and operational issues

Relevant information regarding system reliability and operational issues in the region as feedback is provided by the IESO during the NA phase.

7. Needs

This section describes new needs identified in the Region and updates on previously identified needs since the completion of previous regional planning cycle.

Needs that were identified and discussed in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway, are briefly described below with relevant updates:

- Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region: Seaton MTS has been built and placed in-service in 2023.
- Wilson TS – T1, T2 and Switchyard Refurbishment: Wilson TS T1/T2 have been replaced and new T7/T8 were placed inservice in early 2024, maintaining station reliability and ensuring continued supply reliability to Oshawa PUC Inc. (OPUC) and Hydro One Distribution (H1DX) customers.
- Cherrywood TS – 230kV Breaker Replacements (multi-phase projects): Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.

All near and midterm needs that are discussed as a part of this report are summarized in Table 3. Note the planned in-service year for the projects is tentative and is subject to change.

Table 3: Near/Mid-term Needs Identified in Previous RIP and/or this NA

Need Description	Recommended Plan/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cherrywood TS 230kV Breaker Replacements (multi-phase projects)	Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.	Sec. 7.2	Sec. 7.1
Wilson TS T3/T4 Transformer Replacement	Replacement of T3/T4 transformers with planned in-service date of 2031.	N/A	Sec. 7.1
Station Capacity Needs			
Whitby TS T1/T2 (44kV) Station Capacity need	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning, no further regional coordination is required.	N/A	Sec. 7.2.1
Thornton TS T3/T4 Station Capacity need	Further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 and Wilson TS T7/T8 in Oshawa area (see Section 7.2.3 and 7.2.4).	N/A	Sec. 7.2.2

Wilson TS T7/T8 Station Capacity need	Further regional coordination required to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and a new Transformer Station will be required.	N/A	Sec. 7.2.3
Wilson TS T3/T4 Station Capacity need	A new Transformer Station will be required as early as 2028/2029 and further regional coordination to address this need along with the needs at Wilson TS T7/T8 and Thornton TS T3/T4 (Section 7.2.2 and 7.2.3). As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS.	N/A	Sec. 7.2.4
System Reliability, Operation and Load restoration Needs			
T23C/T29C corridor exceeds load security limit of 600MW	Further regional coordination required, especially when determining where to connect new Transformer Station to accommodate new needs identified in Section 7.2.2, 7.2.3 and 7.2.4.	N/A	Sec. 7.4
Transmission System Reinforcement Needs			
Oshawa-Clarington Sub-region area transmission reinforcement for load supply	Further regional coordination to address the capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.	N/A	Sec. 7.5

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal need for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Region. The complete list of planned major HV transmission equipment requiring replacement is provided in Table 4. Note the in service year is subject to change as the asset renewal planning is a dynamic process.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors
- Technical obsolescence due to outdated design
- Lack of spare parts availability or manufacturer support and/or
- Potential health and safety hazards.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230 load serving step down transformers
- 230kV breakers where:

replacement of six breakers or more than 50% of station breakers, the lesser of the two

- 230kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards.

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

7.1.1 Wilson TS T3/T4

Based on asset condition assessment, Wilson TS T3/T4 transformers are newly identified assets for replacement with currently planned in-service date of 2031. The existing T3 and T4 (75/100/125 MVA) transformers at Wilson TS and associated LV equipment require replacement. It is expected that Wilson TS T3/T4 capacity will increase to approximate 160 MW for Summer and 180 MW for Winter, once being replaced with the new standard 75/100/125 MVA transformers (Section 7.2.4).

No other HV station equipment or transmission lines in the GTA East region have been identified for replacement at this time over the next ten year. If and when new and/or additional information is available, it will be provided during the next regional planning phases.

The needs below in Table 4 do not need further regional coordination.

Table 4: Major HV Transmission Asset Assessed for Replacement in the Region in Next 10 Years

Station/Circuit	Need Description	Planned ISD
Cherrywood TS	230kV Breaker Replacements (multi-phase projects), two phases are underway	2033/2037
Wilson TS T3/T4	Asset condition based replacement with "like for like" standard units	2031

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV Transforming stations in the Region using the summer and winter peak load forecasts. Based on the results, the identified station capacity needs are flagged in Table 5. Comparing with the recommendations in RIP 2022 [1], all Transformer Stations below are newly identified needs in this NA period.

Table 5: Stations with Capacity Need

TS	Season	LTR (MW)	Net Load Forecast (MW)									
			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitby TS T1/T2 (44kV)	Winter	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Thornton TS T3/T4	Summer	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
	Winter	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Wilson TS T7/T8	Summer	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS T3/T4	Summer	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
	Winter	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8

7.2.1 Whitby TS T1/T2 (44kV)

Whitby TS T1/T2 (44kV) supplies loads from one LDC - Elexicon at 44kV level. Elexicon forecasts rapid annual gross load growth of approximate 6.3% at its 44kV service area in North Whitby in next ten years. With forecasted DG and CDM in place, the forecasted net load at Whitby TS T1/T2 (44kV) is expected to exceed its Winter LTR in 2032/2033 by 5MW or 17 MW respectively. In addition, the LDC has indicated that its 44kV distribution capacity at Whitby area will be exceeded by Summer 2032, and majority of the load growth in North Whitby area, which is currently supplied through Whitby TS T3/T4 and Whitby T1/T2 (27.6kV and 44kV), is highly expected post 2033. Also, in Northeast Pickering, there is projected load in the region that cannot be supplied by Whitby TS due to the long distance of the load center from the station.

In order to accommodate these needs, the LDC is currently consulting with Hydro One Tx to build a new Transformer Station, with preliminary option of tapping on two 230kV transmission circuits in the region, namely T28C and P15C. This new Transformer Station will address future projected load growth from North Whiby and North Pickering area. The TWG recommends LDC and Hydro One to proceed to local planning as no expected network reinforcement is required. No further regional coordination is required.

7.2.2 Thornton TS T3/T4

Thornton TS T3/T4 supplies loads from two LDCs, namely Hydro One Distribution (H1DX, with Elexicon's load embedded in) and Oshawa PUC Networks Inc. (OPUC), at 44kV level. OPUC forecasts rapid annual load growth of approximate 4.6% at Thornton TS T3/T4 in next ten years, while Elexicon load forecast remains flat in the study period. With forecasted DG and CDM in place, the net forecasted load at

Thornton TS T3/T4 is expected to exceed its LTRs as early as 2031 for Winter, or 2033 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T7/T8 and Wilson TS T3/T4 in Oshawa area (see Section 7.2.3 and 7.2.4 below).

7.2.3 Wilson TS T7/T8

Wilson TS T7/T8 serves loads from two LDCs, including OPUC and Hydro One Distribution (H1DX) at 44kV level. The two transformers have recently been replaced in early 2024 with largest size as per Hydro One standard transformer specification. Both LDCs forecast similar moderate annual gross load growth of approximate 3.2-3.7% at Wilson TS T7/T8 in next ten years. The net forecasted load at Wilson TS T7/T8 is expected to exceed its LTR as early as 2032 for Summer. The TWG recommends further regional coordination to address this need along with the identified new needs at Wilson TS T3/T4 (Section 7.2.4), and acknowledges that a new Transformer Station will be required for these needs.

7.2.4 Wilson TS T3/T4

Wilson TS T3/T4 serves loads from LDCs OPUC and Hydro One Distribution (H1DX) at 44kV level, with Elexicon's load embedded in H1DX. H1DX (including Elexicon) forecasts approximate 12% annual load growth at Wilson TS T3/T4 in next ten years, while OPUC forecasts moderate growth of approximate 3.6% annually in next ten years. The net forecasted load at Wilson TS T3/T4 is expected to exceed its LTR as early as 2024 for Summer, and 2025 for Winter.

As mentioned in Section 7.1.1, based on asset condition assessment, the T3 and T4 transformers at Wilson TS and associated LV equipment have been identified for replacement. Hydro One has identified the replacement of Wilson TS T3/T4 with planned in-service date of 2031. As the existing transformers have substandard LTRs, it is expected that Wilson TS T3/T4 will be replaced with standard 75/100/125 MVA transformers, and the capacity will increase from the current 130 MW for Summer and 152 MW for Winter to approximately 160 MW for Summer and 180 MW for Winter.

However, even with higher ratings of the new transformers, Wilson TS T3/T4 LTRs will still be exceeded based on load forecast. As a near term solution, the LDCs are encouraged to continue transferring loads to Enfield TS which can accommodate the additional loads that exceed Wilson TS T3/T4 station capacity. By doing so, the station capacity need could potentially be deferred for a few years. The TWG acknowledges that a new station will be required as early as 2028/2029 even with load transfers, and recommends further regional coordination to address this need along with the need in Section 7.2.2 and 7.2.3.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A

Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV Transmission line circuits in the Region by assessing thermal limits of the circuit and the voltage range as per ORTAC[3].

Based on the results, there is no new transmission line capacity need identified.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The system should also meet load security and load restoration criteria as defined in ORTAC[3]. Based on input from the IESO and LDCs, the following system reliability, operational and restoration issues were identified:

- The new load forecast suggests T23C/T29C corridor will exceed load security limit of 600MW[3] in 2032. Table 6 shows load growth of all double-circuit corridors in the Region (assuming all forecasted loads were supplied from original connection points). The TWG recommends further regional coordination to address the T23C/T29C corridor load security issue, especially when determining where to connect the new Transformer Station to accommodate new needs identified in Section 7.2.3 and 7.2.4. The other T24C/T28C corridor will not have more than 600MW net loads in the assessment window.

Table 6: Double-circuit Corridor Non-coincident Load

Circuits		Non-coincident Load served by the double circuits (MW)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
T23C/T29C	Summer	442.6	468.3	486.1	500.7	518.2	538.2	562.8	592.4	638.0	671.0
	Winter	362.1	395.3	420.3	442.1	466.3	493.1	524.0	557.0	605.3	639.5
T24C/T26C	Summer	412.9	418.5	424.1	429.5	435.7	472.5	480.9	489.8	501.5	515.4
	Winter	399.0	414.9	428.3	441.7	456.4	501.6	518.7	534.2	552.6	573.3

- All double-circuit corridor loads will exceed 250MW in this assessment timeframe. The ORTAC[3] requires the amount of load interruption in excess of 250MW must be restored within 30 minutes (and within 4 hours for load loss more than 150MW). The TWG surveyed transmission load interruption performance data from 2014 to 2024 for the Region. The results show that delivery points supplied by the circuits in Table 6 did not log load loss of more than 250MW for longer than 30 minutes, or loss of more than 150MW for longer than 4 hours in the past 10 years. Based on past performance data, the TWG would not recommends capital investment for load restoration at this point. Hydro One shall proactively monitor load restoration data and identify opportunities to reduce risk of prolonged load restoration.

7.5 Transmission System Reinforcement Needs

Oshawa-Clarington Sub-region area transmission reinforcement:

In addition to the rapid organic load growth forecasted in T23C/T29C/T24C/T26C corridors, multiple proponents have requested to connect large-scale loads in Oshawa-Clarington Sub-region area. Majority of the requests are large data centers. It is not feasible for the existing 230kV transmission infrastructure in Oshawa-Clarington Sub-region area to accommodate such sizeable loads. Due to the scale and complexity of such connections, the TWG recommends further regional coordination to address these potential capacity needs. Coordinated efforts from IESO bulk system planning, Hydro One, LDCs and major customers should continue in developing solutions.

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 investments. The TWG determined that the key electric demand driver in the GTA East region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The impact of sensitivity analysis for the high and low growth scenario is shown in Table 7. The additional capacity needs identified towards the end of the study period will be assessed again during the next phases of the Regional Planning cycle where another sensitivity anaylyis will be undertaken based on updated information.

Table 7: Impact of Sensitivity Analysis on Capacity Needs in the Region

No.	Need Identified	Need Date		
		Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
Needs update under high and low load growth scenarios				
1	Whitby TS T1/T2 (44kV) LTR	2032	2030	Beyond 2033
2	Thornton TS T3/T4 LTR	2031	2027	Beyond 2033
3	Wilson TS T7/T8 LTR	2032	2029	Beyond 2033
4	Wilson TS T3/T4 LTR	2024 (2025*)	2024 (2025*)	2024 (Beyond 2033*)
Additional capacity needs under high growth scenario				
5	Cherrywood T7/T8 LTR	Beyond 2033	2031	Beyond 2033
6	Seaton MTS LTR**	Beyond 2033	2032	Beyond 2033
7	Whitby TS T3/T4 LTR	Beyond 2033	2031	Beyond 2033
* If the transformers are replaced with higher LTR rating units as planned. ** Based on the LDC provided LTRs of 153MW (Summer) and 180MW (Winter) for Seaton MTS				

9. Conclusion and Recommendation

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 8: Needs that Do Not Require Further Regional Coordination

No.	Need	Recommendation
1	Cherrywood TS 230kV Breaker Replacement	Replace 230kV Breaker in multi phases. Two phases are underway with currently planned in-service dates of 2033 and 2037 respectively.
2	Wilson TS T3/T4 Transformer Replacement	Replace Wilson TS T3/T4 transformers with "like for like" standard units with currently planned in service date of 2031.
3	Station capacity need at Whitby TS T1/T2 (44kV) due to load growth	Plan a new Transformer Station at North Whitby area, tapping on 230kV circuits of P15C and T28C. TWG agreed to proceed with local planning and no further regional coordination is required.

Table 9: Needs Requiring Further Regional Coordination

No.	Need
1	Transmission reinforcement at Oshawa-Clarington Sub-region area to accommodate large load connection requests and address potential load security issue
2	Station capacity need at Thornton TS T3/T4 due to load growth
3	Station capacity need at Wilson TS T7/T8 due to load growth
4	Station capacity need at Wilson TS T3/T4 due to load growth

List of LDC(s) to be involved in further regional planning activities:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Hydro One Networks Inc. (Distribution)

10. References

[1] Hydro One, RIP Report GTA East 2020 (hydroone.com) (issue February 29, 2020)

[2] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[3] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[4] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. August 2, 2023)

[5] Ontario Energy Board, Distribution System Code (issue July 14, 2000 rev. March 27, 2024)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: GTA East Region – Summer Non-coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	143.4	145.8	148.3	150.8	153.5	156.2	159.3	162.8	163.6	163.1
Seaton MTS	T1/T2	N/A	4.1	10.1	17.0	25.6	36.9	47.0	56.8	66.7	76.7	86.7
Thornton TS	T3/T4	154.9	138.0	138.8	139.5	140.0	141.1	142.4	144.7	147.7	151.5	156.2
Whitby TS	T3/T4	182.4	158.2	159.5	161.0	162.2	163.6	165.1	167.1	169.6	173.4	178.1
Whitby TS	T1/T2 (27.6kV)	99.9	51.8	52.1	52.4	52.6	52.9	53.2	53.7	54.3	55.4	56.8
Whitby TS	T1/T2 (44kV)	100.8	46.1	50.6	55.2	59.9	64.7	69.8	75.5	80.8	87.6	95.4
Wilson TS	T7/T8	169.1	139.7	147.5	149.1	150.8	155.7	159.5	163.4	168.2	174.1	181.3
Wilson TS	T3/T4	130.2	144.6	161.2	176.0	187.7	198.8	213.6	232.2	254.6	290.5	311.6
Enfield TS	T5/T6	161.5	91.7	96.4	99.7	104.0	107.3	110.7	113.5	117.0	121.4	126.5
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.2: GTA East Region – Summer Coincident Normal Growth Net Load Forecast

Transformer Station		Summer LTR (MW)	Summer Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	167.2	136.2	138.5	140.9	143.3	145.8	148.4	151.4	154.7	155.5	154.9
Seaton MTS	T1/T2	N/A	2.7	6.8	11.4	17.1	24.8	31.5	38.1	44.7	51.4	58.1
Thornton TS	T3/T4	154.9	127.0	127.7	128.3	128.8	129.8	131.0	133.1	135.9	139.4	143.7
Whitby TS	T3/T4	182.4	150.3	151.5	152.9	154.0	155.5	156.9	158.8	161.1	164.7	169.2
Whitby TS	T1/T2 (27.6kV)	99.9	49.2	49.5	49.8	50.0	50.3	50.6	51.0	51.6	52.6	53.9
Whitby TS	T1/T2 (44kV)	100.8	43.8	48.1	52.4	56.9	61.4	66.3	71.7	76.8	83.2	90.7
Wilson TS	T7/T8	169.1	125.8	132.8	134.2	135.8	140.2	143.5	147.1	151.4	156.7	163.2
Wilson TS	T3/T4	130.2	130.2	145.1	158.4	168.9	178.9	192.2	209.0	229.1	261.4	280.5
Enfield TS	T5/T6	161.5	85.3	89.7	92.7	96.8	99.8	102.9	105.5	108.8	112.9	117.7
CTS A	N/A		30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
CTS B			46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6
CTS C			38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8	38.8
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Table A.3: GTA East Region – Winter Non-coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	127.8	134.8	140.9	147.0	153.6	160.0	167.1	170.9	170.2	169.6
Seaton MTS	T1/T2	N/A	4.2	10.4	17.5	26.5	38.3	48.8	59.0	69.3	79.7	90.1
Thornton TS	T3/T4	175.5	154.5	157.8	160.3	162.6	165.6	168.9	173.3	178.0	183.7	190.4
Whitby TS	T3/T4	206.2	111.0	117.0	122.3	127.4	132.9	138.3	144.3	149.6	156.1	163.4
Whitby TS	T1/T2 (27.6kV)	112.5	30.9	32.6	34.1	35.5	37.1	38.6	40.3	41.8	43.7	45.8
Whitby TS	T1/T2 (44kV)	113.2	36.6	47.5	56.9	66.6	76.7	87.1	98.1	107.4	118.2	130.1
Wilson TS	T7/T8	184.3	114.9	123.6	126.5	129.6	135.3	140.2	145.1	150.2	156.3	163.4
Wilson TS	T3/T4	152.0	136.1	154.7	171.5	185.1	198.2	214.6	234.6	257.2	293.0	312.8
Enfield TS	T5/T6	183.4	94.7	101.0	105.7	111.3	116.0	120.7	124.7	129.3	134.7	140.9
CTS A	N/A		40	40	40	40	40	40	40	40	40	40
CTS B			97	97	97	97	97	97	97	97	97	97
CTS C			40	40	40	40	40	40	40	40	40	40
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Note:
1. All LTRs are based on 35C for Summer and 10C for Winter.
2. Cherrywood TS DESN LTR is limited by outdoor AL tube, decreasing summer LTR by 8MW.
3. Wilson TS T3/T4 will be replaced by 2031 with higher rating of approximate 160MW for Summer and 180MW for Winter.

Table A.4: GTA East Region – Winter Coincident Normal Growth Net Load Forecast

Transformer Station		Winter LTR (MW)	Winter Non-Coincident NET Forecast (MW) - Normal Growth									
Name	DESN ID		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cherrywood TS	T7/T8	204.5	125.2	132.1	138.1	144.1	150.5	156.8	163.7	167.5	166.8	166.2
Seaton MTS	T1/T2	N/A	2.6	6.4	10.9	16.4	23.8	30.2	36.6	43.0	49.4	55.9
Thornton TS	T3/T4	175.5	140.6	143.6	145.9	148.0	150.7	153.7	157.7	162.0	167.2	173.3
Whitby TS	T3/T4	206.2	108.8	114.7	119.8	124.8	130.2	135.6	141.4	146.6	153.0	160.1
Whitby TS	T1/T2 (27.6kV)	112.5	30.2	31.9	33.4	34.8	36.3	37.8	39.5	41.0	42.8	44.8
Whitby TS	T1/T2 (44kV)	113.2	35.9	46.6	55.8	65.3	75.1	85.4	96.1	105.2	115.8	127.5
Wilson TS	T7/T8	184.3	108.0	116.2	118.9	121.8	127.2	131.8	136.4	141.2	146.9	153.6
Wilson TS	T3/T4	152.0	128.0	145.4	161.2	174.0	186.3	201.7	220.5	241.8	275.4	294.0
Enfield TS	T5/T6	183.4	87.1	92.9	97.2	102.4	106.7	111.1	114.7	118.9	123.9	129.6
CTS A	N/A		35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2	35.2
CTS B			86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3
CTS C			34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Metrolinx TPSS			0	0	0	0	0	30	30	30	30	30

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station		Voltage (kV)	Supply Circuits
1	Cherrywood TS	T7/T8	230/44	Cherrywood TS, DK Bus
2	Seaton MTS	N/A	230/27.6	C10A/T28C
3	Thornton TS	T3/T4	230/44	T24C/T26C
4	Whitby TS	T1/T2	230/27.6	T24C/T26C
			230/44	
		T3/T4	230/44	T23C/T29C
5	Wilson TS	T1/T2	230/44	T23C/T29C
		T3/T4	230/44	
6	Enfield TS	T5/T6	230/44	Clarington TS, PK Bus
7	CTS A	N/A	N/A	T24C/T26C
8	CTS B	N/A	N/A	T24C/T26C
9	CTS C	N/A	N/A	T24C/T26C

Appendix C: Lists of Transmission Circuits

No.	Circuit ID	From Station	To Station	Voltage (kV)
1	C10A	Cherrywood TS	Seaton MTS	230
2	T23C	Cherrywood TS	Clarington TS	230
3	T24C	Cherrywood TS	Clarington TS	230
4	T26C	Cherrywood TS	Clarington TS	230
5	T28C	Cherrywood TS	Clarington TS	230
6	T29C	Cherrywood TS	Clarington TS	230

Appendix D: List of LDC's

No.	Name of LDC	Connection Type (TX/DX)
1	Elexicon Energy Inc.	TX / DX
2	Oshawa PUC Networks Inc.	TX / DX
3	Hydro One Networks Inc. (Distribution)	TX

Appendix E: List of Municipalities in the region

No.	Name of Municipality
1	City of Pickering
2	Town of Ajax
3	Town of Whitby
4	City of Oshawa
5	Municipality of Clarington
6	Township of Scugog
7	Township of Uxbridge
8	Regional Municipality of Durham

Appendix F: Acronyms

Acronym	Description
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
KOP	Key Operating Point
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LP	Local Plan
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
MVGIS	Medium Voltage Gas Insulated Switchgear
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SS	Switching Station
TS	Transformer Station

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX B
GTA EAST – SCOPING ASSESSMENT



GTA East Region

Scoping Assessment Outcome Report

April 25, 2025

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Connecting Today.
Powering Tomorrow.

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1. Introduction

This scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process and sets out the planning approach to address electricity needs that have been identified in the GTA East. The OEB started regional planning in 2011 and endorsed the Planning Process Working Group's Report to the Board in May 2013. The Board formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

This is the third cycle of regional planning for the GTA East region, and it was initiated in summer 2024. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). The Needs Assessment[1] was finalized on December 11, 2024, and flagged a number of needs requiring further regional coordination as well as a few needs to be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

As part of the Scoping Assessment, the Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them. The planning approaches considered include:

- **An Integrated Regional Resource Plan (IRRP)** led by the Independent Electricity System Operator (IESO) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required;
- **A Regional Infrastructure Plan (RIP)** led by the transmitter – which considers more straight-forward wires only option with limited engagement; or
- **A local plan (LP)** undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is required.

This Scoping Assessment report is structured as follows:

- Section 2 lists the study team.
- Section 3 provides an overview of the region, the previous regional planning cycle, and major transmission reinforcement since the previous cycle.
- Section 4 summarizes the new and updated needs as described in the NA.
- Section 5 describes the criteria used to select a regional planning approach and specifies the scope of the IRRP.

Appendix 1 defines the acronyms used in this document and Appendix 2 establishes the Terms of Reference for the IRRP and the composition of the IRRP Technical Working Group (TWG).

[1] 2024 GTA East Needs Assessment, Hydro One. (Link)

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Hydro One Transmission)
- Hydro One Networks Inc. (Hydro One Distribution)
- Elexicon Energy Inc.
- Oshawa Power and Utilities Company (Oshawa PUC)

3. Overview of Region and Background

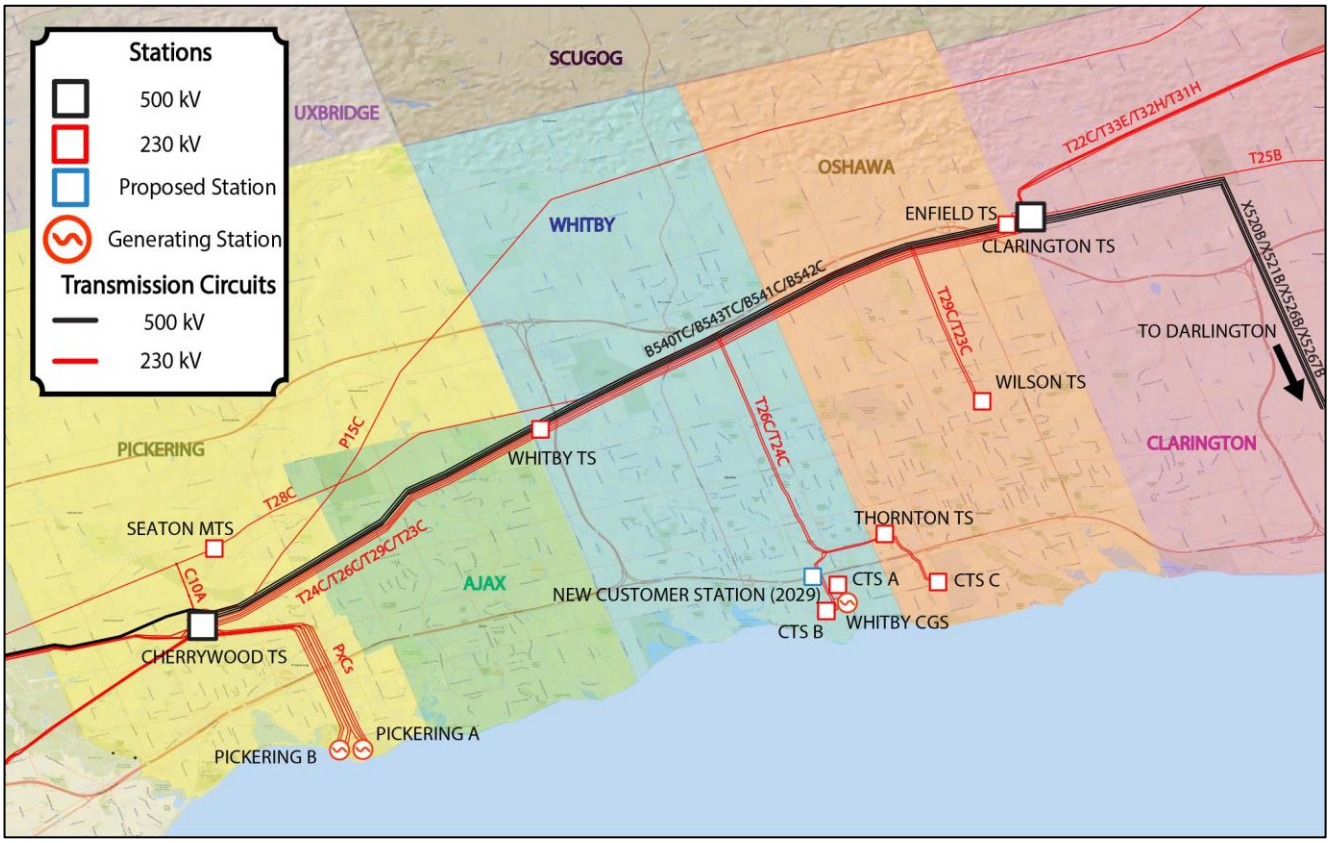
3.1 Overview of the GTA East Region

The GTA East region, shown in **Figure 1**, extends from Lake Ontario northward to the southern parts of Scugog and Uxbridge, and includes the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington within Durham Region.

With respect to Indigenous communities, this region includes:

- Alderville First Nation
- Chippewas of Beausoleil First Nation
- Chippewas of Georgina Island First Nation
- Chippewas of Rama First Nation
- Curve Lake First Nation
- Hiawatha First Nation
- Kawartha Nishnawbe
- Mississaugas of Scugog Island First Nation
- Mississaugas of the Credit First Nation
- Métis Nation of Ontario

Figure 1 | Overview of the GTA East Region

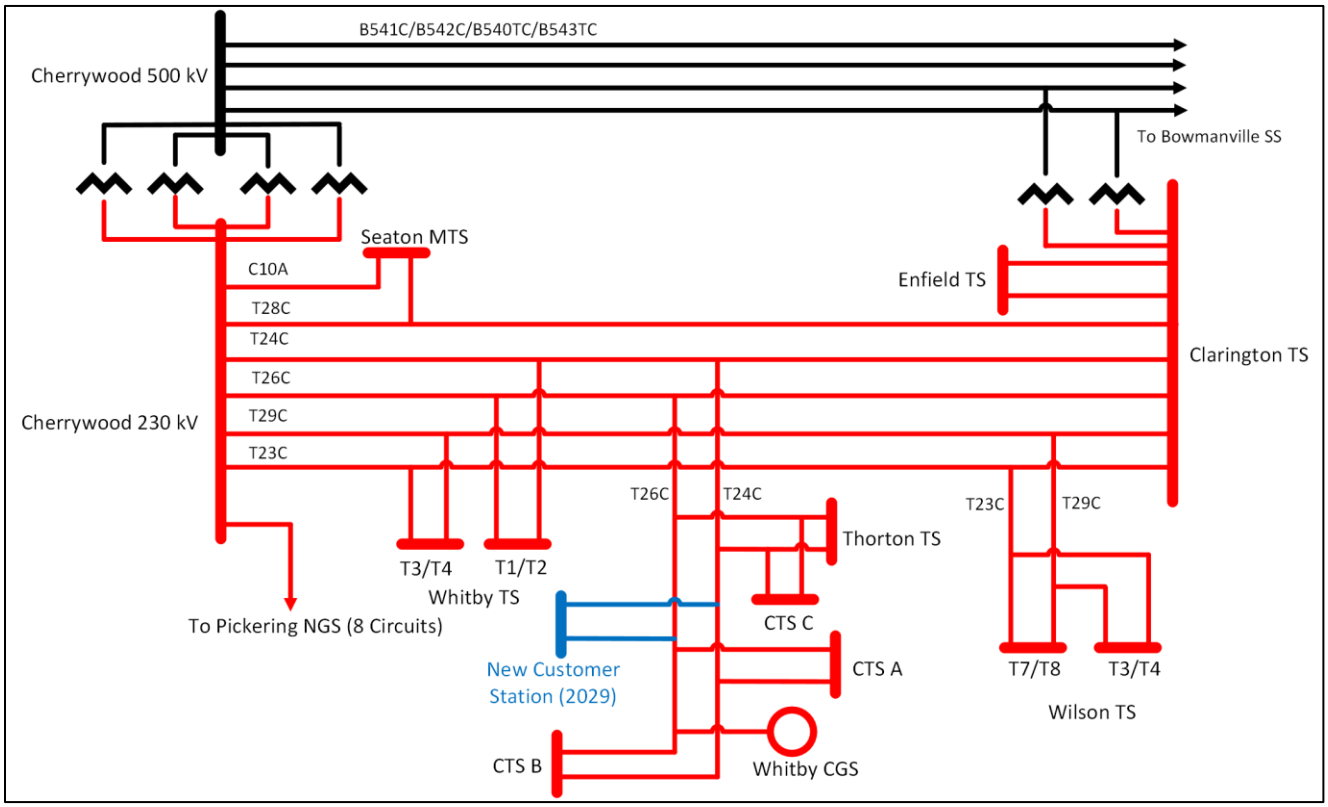


3.1.1 Electricity System Supplying GTA East Region

Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. As shown in **Figure 2**, electrical supply to the GTA East Region is provided through 500/230 kilovolt (kV) autotransformers at Cherrywood Transformer Station (TS), Clarington TS and six 230kV transmission lines connecting Cherrywood TS to Clarington TS. There are six step-down transformer stations (five Hydro One owned and one LDC owned), one Customer Station which is proposed to be in service in 2029[2], and three direct transmission connected load customers. Whitby Customer Generating Station (CGS), a 60 MW gas-fired cogeneration station, also provides a local source of supply within the region. Pickering Nuclear Generating Station (NGS) is connected to the Cherrywood TS through eight circuits, and it produces approximately 3000 MW of supply.

[2] For more information regarding new Customer Station, refer to Hydro One's 2024 GTA East Needs Assessment (Link)

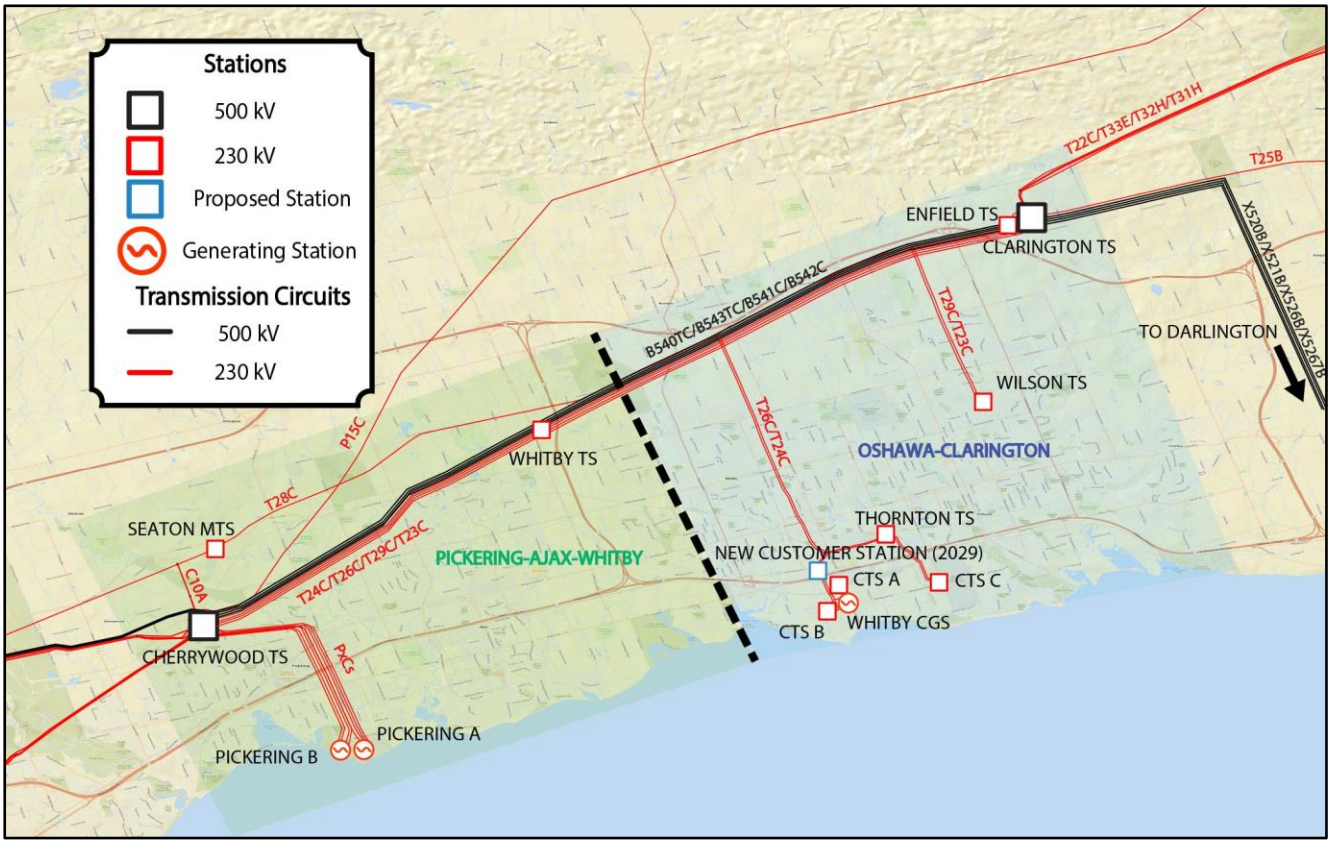
Figure 2 | Single Line Diagram of the GTA East Region



For the previous regional plans, the study team has divided GTA East Region into two sub-regions as shown in **Figure 3**:

- **Pickering-Ajax-Whitby Sub-Region** – includes the area served by Cherrywood TS, Whitby TS, and Seaton MTS and the 230kV lines connection transmission facilities in the area (includes most of the City of Pickering, Town of Ajax, and part of the Town of Whitby, and part of the Township of Uxbridge and Scugog)
- **Oshawa-Clarington Sub-Region** – includes the area served by Clarington TS, Thornton TS, Wilson TS, Enfield TS, proposed Customer Station, three customer connection station, a gas fired cogeneration station and the 230kV lines connecting the transmission facilities (includes the City of Oshawa, part of the Municipality of Clarington and part of the Township of Scugog).

Figure 3 | Sub-Regions of the GTA East Region



3.2 Previous Regional Plans

The first cycle of the regional planning process for GTA East was completed in 2016 with the publication of the Region's first IRRP[3]. This plan focused on the Pickering-Ajax-Whitby Sub-Region where it used a 20-year demand forecast and made recommendations to address near-term capacity needs. Through this regional planning cycle, Seaton Municipal Transformer Station (MTS) was recommended and implemented. Simultaneously, the first Local Plan was conducted which focused on the Oshawa-Clarington Sub-Region. This plan recommended and implemented Enfield TS to address the Wilson TS and Thornton TS station capacity needs.

The second cycle of the regional planning process was completed in 2019. During this regional planning process, a Needs Assessment[4] did not identify any needs in the area requiring regional coordination and integrated planning, resulting in the publication of the RIP[5]. Through this plan, the Technical Working Group (TWG) recommended continuing investments in existing plans, which includes refurbishing the Wilson TS and Cherrywood TS Switchyard.

[3] 2016 Pickering-Ajax-Whitby Integrated Regional Resource Plan (IRRP), IESO. (Link)
[4] 2019 GTA East Needs Assessment, Hydro One. (Link)
[5] 2019-2024 GTA East Regional Infrastructure Plan, Hydro One. (Link)

This current, third regional planning cycle started with the publication of the Needs Assessment report by Hydro One in December 2024. The needs identified in the Needs Assessment report form the basis of the analysis for this Scoping Assessment and are further discussed in the Section 4.

4. Summary of New and Updated Needs

This section briefly summarizes the new and updated needs identified in the Needs Assessment report. Please refer to the full Needs Assessment report for more details. The Needs Assessment only identified station capacity, supply capacity, load security/restoration, and asset replacement need which will be described in the following sub-sections. Note that this section documents all identified needs regardless of whether or not further regional coordination is required. Section 5 specifies the planning approach and outlines the specific needs that will be in scope for subsequent regional planning stages.

4.1 Station Capacity Needs

Station capacity refers to the ability to convert power from the transmission system down to distribution system voltages. Station capacity needs were identified at Whitby TS, Wilson TS, and Thorton TS as described in **Table 1**.

Table 1 | Station Capacity Needs

#	Station	Assessment
1	Whitby TS T1/T2	Whitby TS T1/T2 is expected to reach capacity by 2032 for winter. The Needs Assessment recommended LDC and Hydro One to proceed to local planning to address this need. The TWG will continue exploring the option of building a new TS in North Whitby area during the IRRP.
2	Thornton TS T3/T4	Thorton TS T3/T4 is expected to reach capacity by 2031 for winter and 2033 for summer. The Needs Assessment recommended further regional coordination to address this need along with the identified station capacity needs at Wilson TS T3/T4 and T7/T8 in Oshawa area.
3	Wilson TS T3/T4	Wilson TS T3/T4 is already at capacity for summer and expected to reach capacity by 2025 for winter. Hydro One has identified the replacement of Wilson TS T3/T4 with a planned in-service date of 2031. With higher ratings of new transformers, the Wilson TS T3/T4 LTR will still be exceeded. The Needs Assessment recommended further regional coordination to address this need.
4	Wilson TS T7/T8	Two transformers have been replaced in early 2024 with the largest size. Wilson TS T7/T8 is expected to reach capacity by 2032 for summer. The Needs Assessment recommended further regional coordination to address this need.

4.2 Supply Capacity Needs

Supply capacity (or "load meeting capability") refers to the ability of the electricity system to supply power to customers in the area either by generating the power locally or brining it in through the transmission system.

Supply capacity needs were identified in the Needs Assessment report for the Oshawa-Clarington area. Multiple proponents, especially large data centers, have requested to connect in the region, but it is not feasible for the existing 230kV transmission infrastructure to accommodate these loads. Due to the scale and complexity of the loads and connection, the Needs Assessment suggested further regional coordination to address this need.

4.3 Load Security and Restoration Needs

Load security describes the total amount of load interrupted following major transmission outages. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes.

Load security needs were identified at the T23C/T29C corridor. The T23C/T29C corridor is expected to exceed load security limit of 600 MW in 2032, which violates Ontario Resource and Transmission Assessment Criteria (ORTAC) standards. The Needs Assessment recommends further regional coordination to address this load security issue, especially when determining where to connect the new Transformer Station to accommodate new needs identified in Section 4.1.

Based on the 10-year forecast developed by the study team, all double-circuit corridor (T23C/T20C and T24C/T26C) loads will exceed 250 MW. The ORTAC requires that load interruption exceeding 250MW must be restored within 30 minutes. Based on the past performance data, the Needs Assessment did not recommend capital investment for load restoration at this point.

4.4 Asset Replacement Needs

The Needs Assessment identified asset replacement needs at Wilson TS and its associated Lower Voltage (LV) equipment, as shown in **Table 2**. It also provides an update on one of the plans from the second-cycle RIP, specifically the 230kV breaker replacement at Cherrywood TS, which is currently underway. The Needs Assessment did not recommend further regional coordination for these needs but advised proceeding with the plan.

Table 2 | Asset Renewal Needs

#	Station	Need Description	Recommended Plan/Update
5	Cherrywood TS	230kV Breaker Replacement	Two phases are currently underway with planned in-service dates of 2033 and 2037 respectively.
6	Wilson TS T3/T4	Transformer Replacement	Replacement of T3/T4 transformers with planned in-service date of 2031.

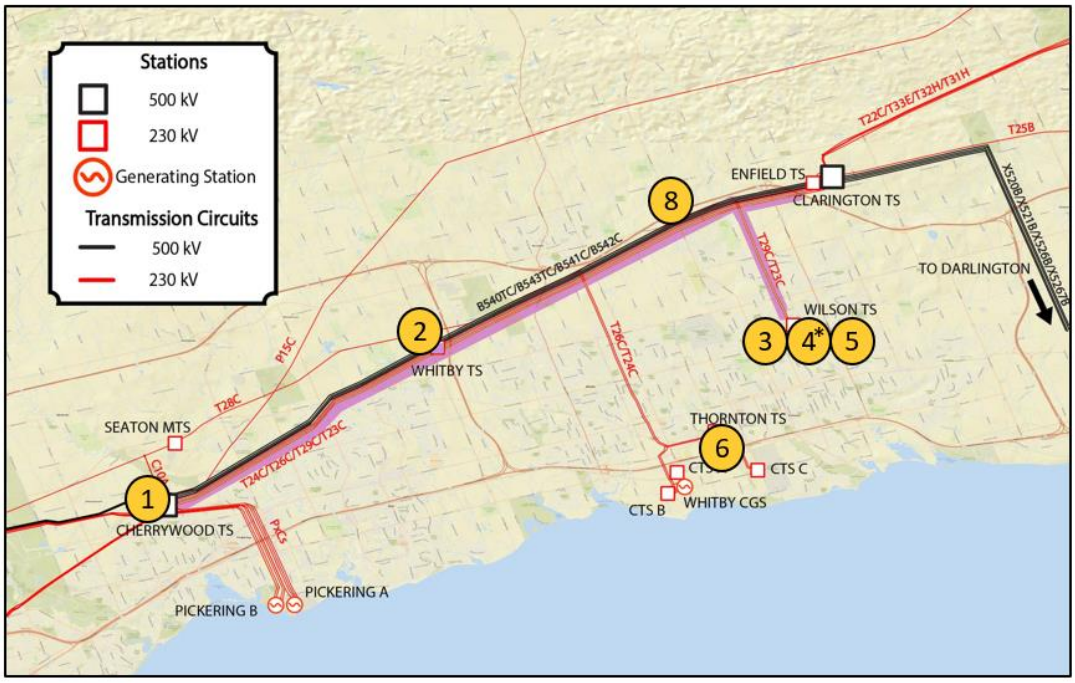
4.5 Summary of the Needs

The needs identified in the Needs Assessment are summarized in **Table 3**. Their geographical locations are shown in **Figure 4**.

Table 3 | Summary of Needs Identified from Needs Assessment

#	Need	Need Type	Timing	Need Description
1	Cherrywood TS	Asset Replacement	2033-2037	Breaker replacements, two phases currently underway with planned in-service dates of 2033 and 2037
2	Whitby TS T1/T2	Station Capacity	2032	Station overload, but there is a proposed plan for a new TS in the North Whitby area tapping to P15C and T28C
3	Wilson TS T3/T4	Asset Replacement	2031	Replacement of T3/T4 transformers with planned in-service date of 2031
4	Wilson TS T3/T4	Station Capacity	2024	Station overload, with planned transformer replacement, this need timing shifts to 2025
5	Wilson TS T7/T8	Station Capacity	2032	Station overload
6	Thorton TS T3/T4	Station Capacity	2031	Station overload
7	Oshawa-Clarington	Supply Capacity	N/A	Need for transmission reinforcement due to large load connection requests
8	T23C/T29C	Load Security	2032	This corridor exceeds the load security limit of 600 MW in 2032

Figure 4 | Geographic Location of Needs Identified in Needs Assessment



5. Regional Planning Approach

Needs identified through the Needs Assessment were reviewed during the Scoping Assessment to determine whether a Local Plan, Regional Infrastructure Plan, or Integrated Regional Resource Plan regional planning approach is most appropriate.

For the GTA East region, an IRRP is recommended. The following sections outline the selection criteria, and the scope of the recommended IRRP.

5.1 Selection Criteria

A LP process is recommended when needs:

- Are local in nature (only affecting one LDC or customer)
- Are limited investments of wires (transmission or distribution) solutions
- Do not require upstream transmission investments
- Do not require plan level community and/or stakeholder engagement and,
- Do not require other approvals such as a Leave to Construct application or Environmental Approval.

If it is determined that coordinated planning is required to address identified needs, either a RIP or an IRRP may be initiated. In general, an IRRP is initiated wherever:

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the Needs Assessment;
- Community or stakeholder engagement is required; or,
- The planning process or outcome has the potential to impact bulk system facilities

If it is determined that the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, a RIP will be selected instead.

Wires type transmission/distribution infrastructure solutions refer, but are not limited, to:

- Transmission lines
- Transformer/Switching station (SS)
- Sectionalizing devices including breakers and switches
- Reactors or compensators
- Distribution system assets

Additional solutions, including energy efficiency, generation, and other electricity initiatives can also play a significant role in addressing needs. Because these solutions are non-wires alternatives, they must be studied through an IRRP process.

5.2 Integrated Regional Resource Plan Scope of Work

The previous regional planning cycles divided the region into two sub-regions. However, this Scoping Assessment recommends a single IRRP that covers the entire GTA East region, but with a focus on issues highlighted in this section.

Note that the primary purpose of an IRRP is to study regional needs that require coordination between transmitters, distribution companies, and the IESO. The IRRP will not study bulk system needs but the findings from the IRRP will be coordinated with the South and Central bulk studies and vice-versa to ensure alignment between bulk and regional plannings[6]. Additionally, the IRRP will not specifically address new customer transmission connection request unless there is an opportunity to align with broader regional needs. While the IRRP welcomes information from project proponents to inform load forecasting and to ensure plans for regional infrastructure are adequate, individual customer connection requests may be better suited for a proponent driven Technical Feasibility Study.

The Scoping Assessment recommends that for each of the identified needs shown in **Table 4**, a range of alternatives including wires and non-wires solutions should be explored in a coordinated manner by the TWG. However, the following two needs from **Table 3** have been identified as not requiring further study:

- The work to replace the breakers at Cherrywood TS was discussed in a previous planning cycle and is currently underway.
- For the Wilson TS T3/T4 end-of-life need it was determined that a like-for-like replacement will be made as the transformers are already the largest size available for the 230/44kV voltage (75/100/125MVA). However, there are still station capacity needs that have been identified for Wilson TS and require further study, which are included in **Table 4**.

Additionally, planning work regarding a new transformer station to address the Whitby TS station capacity need has been ongoing. Elexicon and Hydro One Transmission have presented their findings to the TWG as part of the Needs Assessment process and the IRRP will further study potential options, their impact on the electricity system, and provide a clear recommendation.

Table 4 | Needs Identified in the Scoping Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
Whitby TS T1/T2	Station Capacity	2032
Wilson TS T3/T4	Station Capacity	2024
Wilson TS T7/T8	Station Capacity	2032
Thorton TS T3/T4	Station Capacity	2031

[6] South and Central Bulk Planning Engagement Page, IESO. (Link)

Facilities	Type of Need	Expected Timing
Oshawa-Clarington (T23C/T29C/T24C/T26C)	Supply Capacity	N/A
T23C/T29C	Load Security	2032

Based on discussion, the TWG agreed that an IRRP is the preferred planning approach. A Terms of Reference for the IRRP is attached in Appendix 2.

6. Conclusion and Next Steps

The Scoping Assessment concludes that a single IRRP covering the entire GTA East Region will be undertaken to address the following items as discussed according to Section 5.2.

As further technical studies and community engagement are undertaken through the IRRP, new needs may appear and be included in the scope of the IRRP. All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as discussion of any local initiatives focused on energy and/or reducing greenhouse gas (GHG) emissions, and how the IRRP can coordinate with these plans. The Terms of Reference for the GTA East IRRP can be found in Appendix 2.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CGS	Customer Generating Station
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
FIT	Feed-in-Tariff
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTR	Long-Term Rating
MTS	Municipal Transformer Station
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station
TWG	Technical Working Group

Appendix 2 – GTA East IRRP Terms of Reference

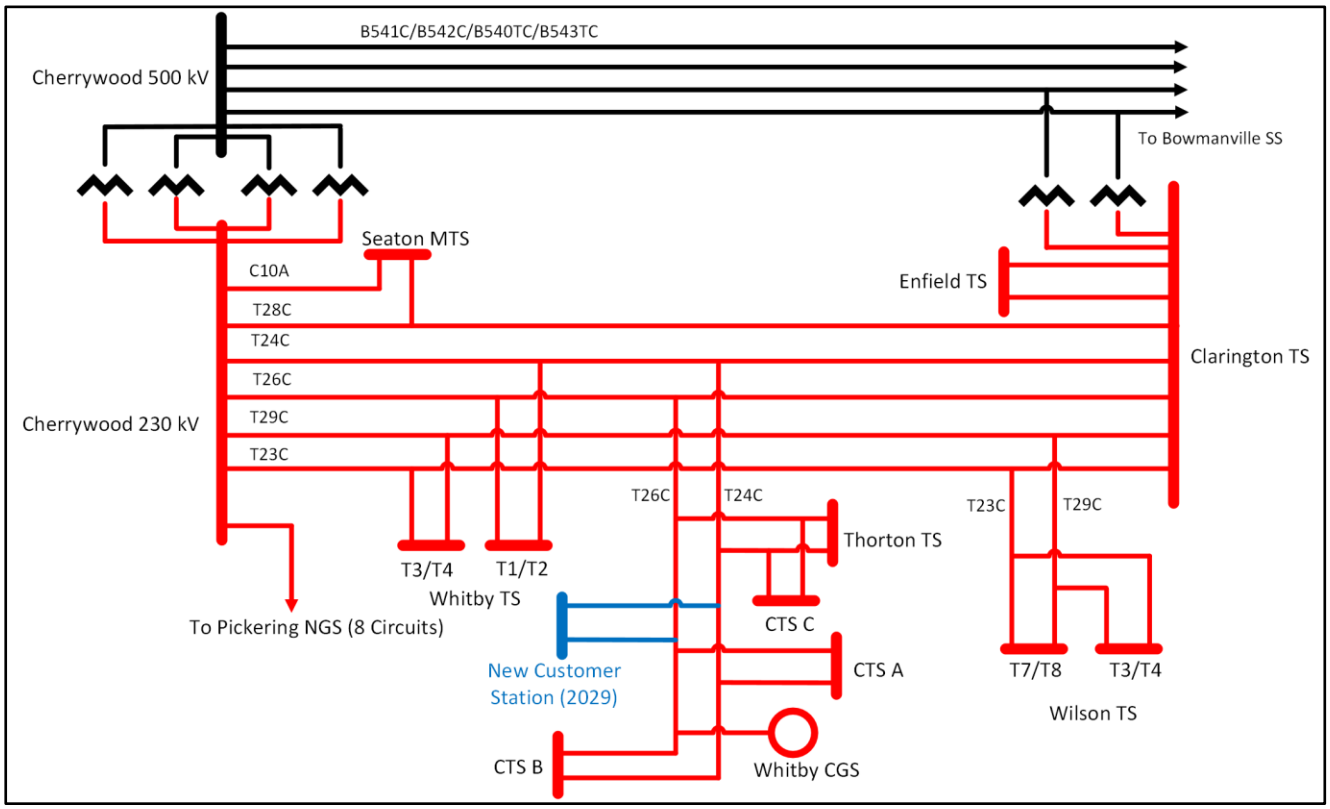
1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) of the GTA East region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

The single line diagram of the GTA East region is shown in **Figure A 1**.

Figure A 1 | Single Line Diagram for GTA East Region



2. Objectives

The GTA East IRRP will be developed based on the following objectives:

1. To assess the adequacy of electricity supply to customers in the GTA East Region over the next 20 years.
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 approach for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility 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 directions for the long-term.

3. Scope

This IRRP will develop and recommend an integrated plan to address the needs of the GTA East region. The plan is a joint initiative led by the IESO and completed by the members of the TWG - Hydro One Distribution, Hydro One Transmission, Elexicon Energy, and Oshawa PUC. The plan will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life major facilities in the area, relevant community plans, other bulk system developments, generation uptake, and will develop an integrated plan to address needs.

The scope of the GTA East IRRP includes the needs shown in **Table A 1**, as identified in the Needs Assessment.

Table A 1 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
Whitby TS T1/T2	Station Capacity	2032
Wilson TS T3/T4	Station Capacity	2024
Wilson TS T7/T8	Station Capacity	2032
Thorton TS T3/T4	Station Capacity	2031
Oshawa-Clarington (T23C/T29C/T24C/T26C)	Supply Capacity	N/A
T23C/T29C	Load Security	2032

Cherrywood TS breaker replacements will continue as planned, where two phases are currently underway with planned in-service dates of 2033 and 2037.

The GTA East Region IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe
- Examine the load meeting capability and reliability of the existing transmission system supplying the GTA East Region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of EE, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the GTA East region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

3.1 South and Central Ontario Bulk Planning Study

The Bulk Planning Study will examine the capability of the bulk system to support future generation connections and demand growth in key areas throughout the province, to enable a decarbonized power system in the future.

As the South and Central Bulk Study[7] will be conducted in parallel with regional planning in GTA East, its findings (i.e., needs and recommended solutions) will be coordinated with the GTA East IRRP, and vice-versa.

4. Data and Assumptions

The plan will consider the following data and assumptions:

Demand Data

- Historical non-coincident peak demand information
- Median and extreme weather conditions
- Gross peak demand forecast scenarios
- Forecasted regional coincident peak demand data including transmission-connected customers
- Identified potential future load customers
- Customer/load segmentation information (e.g., residential, commercial, industrial) by TS

Conservation and Demand Management

- Conservation forecasts for LDC customers, based on region's share of current energy efficiency programs

[7] South and Central Bulk Planning Engagement Page, IESO. (Link)

- Potential for CDM at transmission-connected customers' facilities

Local resources

- Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
- Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
- Future district energy plans, combined heat and power, energy storage, or other generation proposals

Relevant local and provincial plans and studies, as applicable

- LDC Distribution System Plans
- Community Energy Plans and Municipal Energy Plans
- Municipal and community policies with an impact on electricity usage
- Municipal Growth Plans
- Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion and electrification (e.g. GO train electrification)
- Pathways to Decarbonization Report
- Gatineau Transmission Corridor

Criteria, codes and other requirements

- Ontario Resource and Transmission Accessibility Criteria (ORTAC)
- NERC and NPCC reliability criteria, as applicable
- OEB Transmission System Code
- OEB Distribution System Code
- Reliability considerations, such as the frequency and duration of interruptions to customers
- Other applicable requirements

Existing system capability

- Transmission line ratings as per transmitter records
- System capability as per computer simulation results using the current IESO base cases
- Transformer station ratings (10-day LTR) as per asset owner
- Load transfer capability
- Technical and operating characteristics of local generation

End-of-life asset consideration/sustainment plans

- Transmission assets
- Distribution assets

Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Networks Inc. (Hydro One Transmission)
- Hydro One Networks Inc. (Hydro One Distribution)
- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.

5.1 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.

6. 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.

As such, the IESO, in consultation with the TWG, is committed to conducting engagement in accordance with IESO Engagement Principles throughout the development of the IRRP. The first step in engagement will consist of the development of an engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

#	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	IESO	Finalized Terms of Reference	Q1 2025
2	**Develop the planning forecast for the region**		Long-term planning forecast scenarios	Q2 2025
2.1	Establish historical non-coincident peak demand information	IESO		
2.2	Establish historical weather correction, median and extreme conditions	IESO		

#	Activity	Lead Responsibility	Deliverable(s)	Timeframe
2.3	Establish gross peak demand forecast	LDCs		
2.4	Establish existing, committed, and potential DG	IESO, LDCs		
2.5	Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
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**	LDCs/Hydro One	Load transfer capabilities under normal and emergency conditions	Q2 2025
4	**Provide and review relevant community plans, if applicable**	LDCs, communities, stakeholders, and IESO	Relevant community plans	Q2 2025
5	**Complete system studies to identify needs over a twenty-year period**	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q3-Q4 2025
5.1	Obtain base case			
5.2	Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios			
5.3	Confirm and refine the need(s) and timing/load levels			
6	**Develop options and alternatives**		Develop flexible planning options for forecast scenarios	Q4 2025 - Q1 2026
6.1	Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
6.2	Verify the LMC of the system to better determine timing of needs and support options development	IESO		

#	Activity	Lead Responsibility	Deliverable(s)	Timeframe
6.3	Develop screened-in energy efficiency options	IESO and LDCs		
6.3	Develop screened-in local generation/demand management options	IESO and LDCs		
6.4	Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
6.5	Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
6.6	Technical and economic comparison and evaluation of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
7	**Plan and undertake community and stakeholder engagement**		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Metis Nation of Ontario	Ongoing as required IRRP engagement to be launched in
7.1	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 Metis Nation of Ontario	IESO, Hydro One Transmission, and LDCs		
7.2	Develop communications materials	IESO, Hydro One Transmission, and LDCs		
7.3	Undertake community and stakeholder engagement	IESO, Hydro One		

#	Activity	Lead Responsibility	Deliverable(s)	Timeframe
		Transmission, and LDCs		
7.4	Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedure for annual review	Q1–Q2 2026
9	**Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties**	IESO	IRRP report	Q3 2026 - Sept 2026

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EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX C
GTA NORTH – NEEDS ASSESSMENT

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

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.

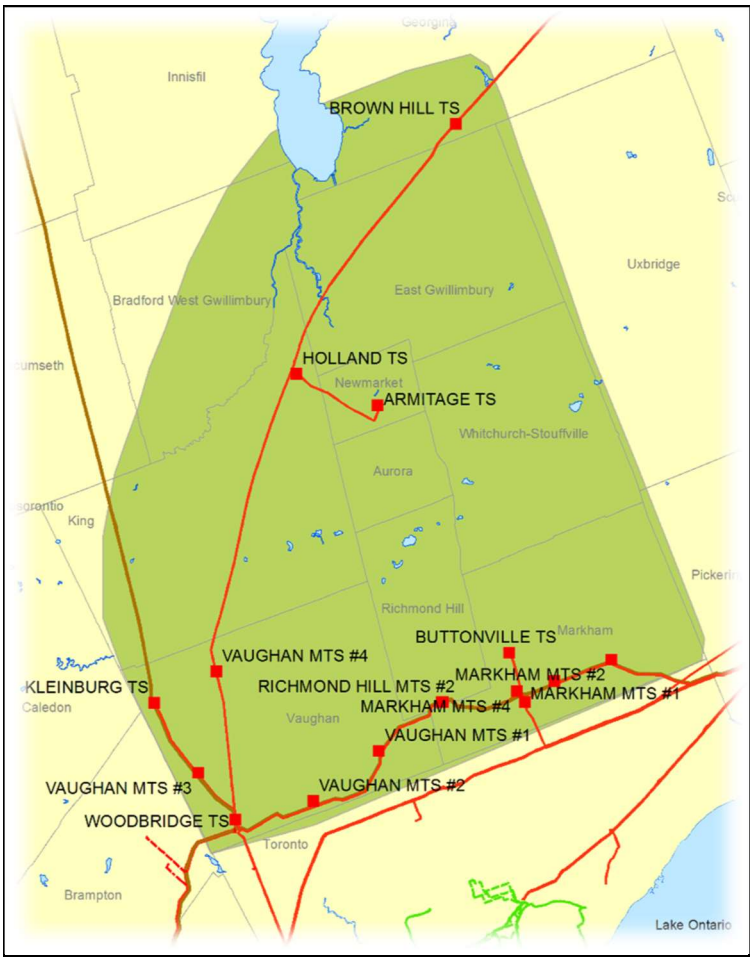


Figure 4-1: GTA North Region Map

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.

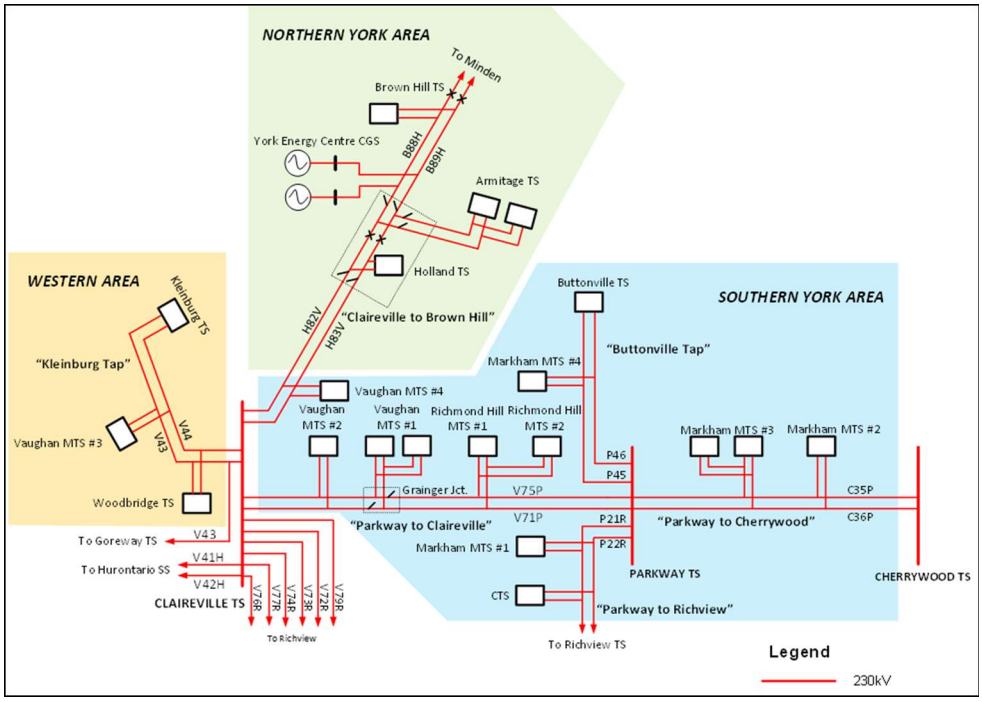


Figure 4-2: GTA North Region– Single Line Diagram

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. Load restoration following loss of the Claireville TS x Kleinburg TS 230kV circuits (V43/V44).

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. Load Restoration following loss of the Claireville TS to Holland TS circuits (H82V/H83V).

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. Load Security Need for the Parkway TS to Claireville TS 230kV double circuit Line V71P/V75P

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. Load Restoration Need for the Parkway TS to Buttonville TS 230kV double circuit Line P45/P46

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.

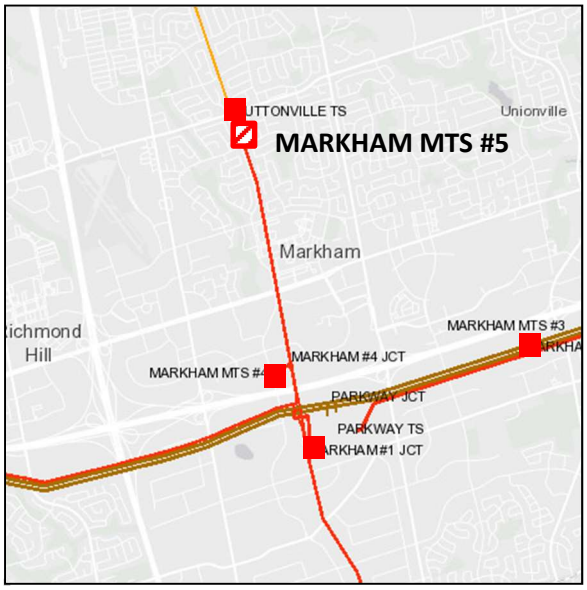


Figure 8-1: Markham MTS #5 Location

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.

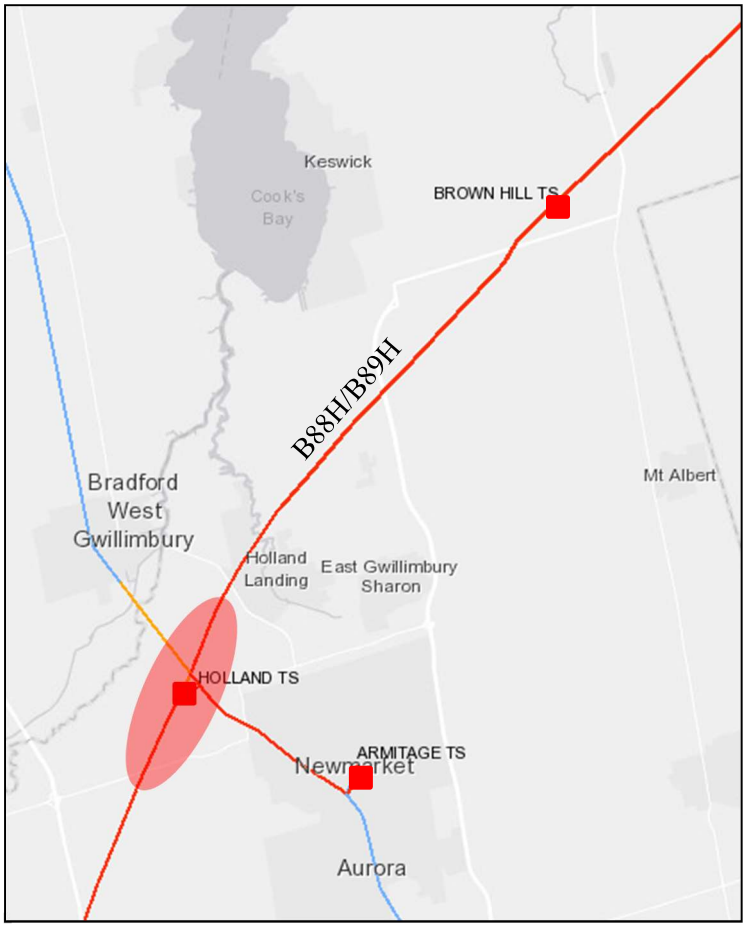


Figure-8-2 Northern York Area TS – Potential Location

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.

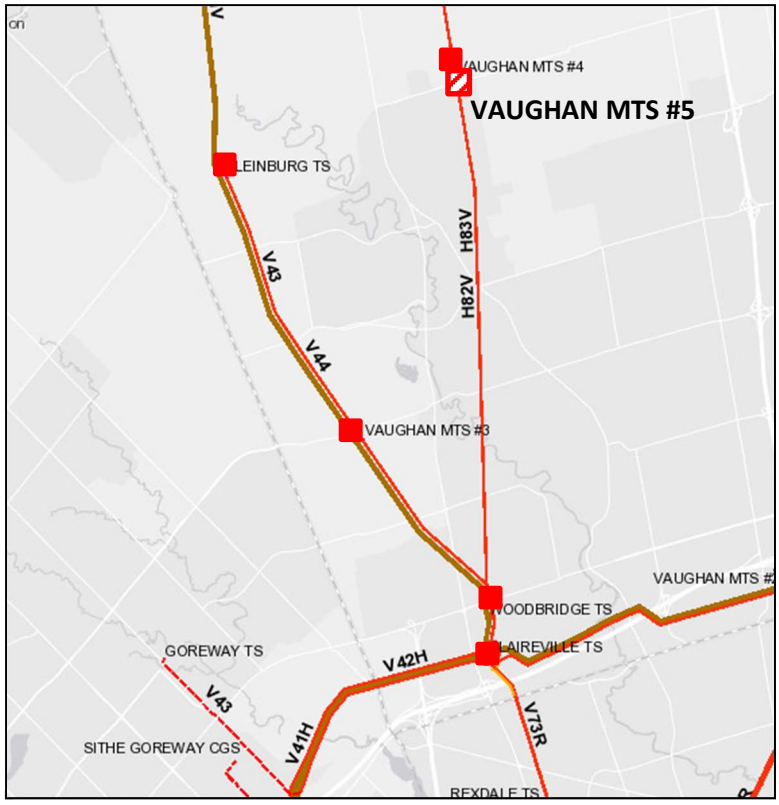


Figure-8-3 Vaughan MTS #5 Location

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.

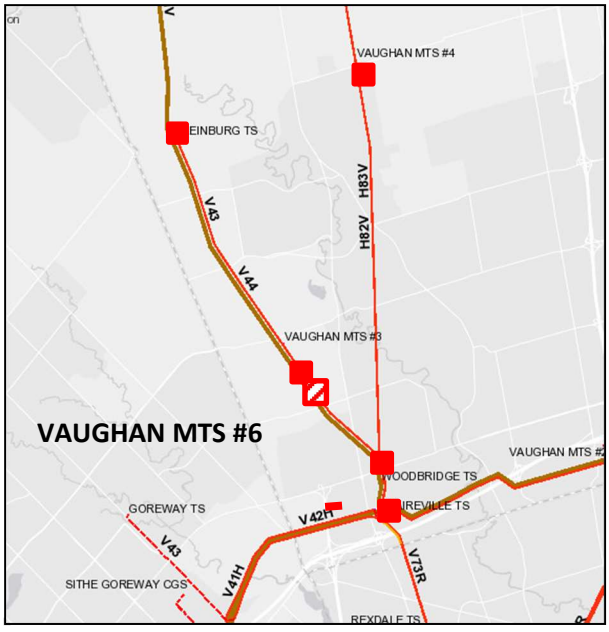


Figure-8-4 Vaughan MTS #6 Location

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.

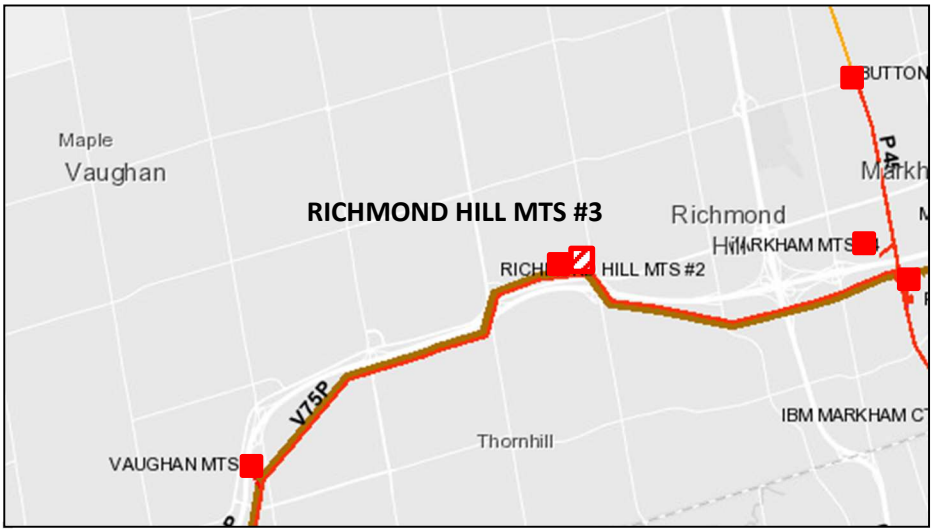


Figure-8-5 Richmond Hill MTS #3 Location

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

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX D
GTA NORTH – SCOPING ASSESSMENT



GTA North (York Region) Scoping Assessment Outcome Report

October 12, 2023

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Connecting Today.
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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 GTA North region (also known as "York Region"), and it was initiated in March 2023. Information and links to earlier products are available on the IESO webpage[1]. 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[2] was finalized on July 14, 2023 and identified needs that require further regional coordination. The Technical Working Group reviewed the nature and timing of all the needs identified in the region through the Needs Assessment process, to determine the most appropriate planning approach. It also considered provincial initiatives, including the IESO's recent Pathways to Decarbonization report and the provincial government's Powering Ontario's Growth report.

The Scoping Assessment process considers which of three potential planning approaches is most appropriate for addressing the region's needs, including: an IRRP – where both wires and non-wires options have the potential to address the needs and are considered as alternatives; a Regional Infrastructure Plan (RIP), which considers only wires (transmission and distribution) options; or a local plan undertaken by the transmitter and affected local distribution company or customer, 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 determines whether sub-regions should be defined;
- 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.

[1] GTA North (York Region) Regional Planning Webpage, IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/GTA-North

[2] Needs Assessment Report GTA North Region, Hydro One. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/GTA%20North%20Region%20NA%20Report%20Final%20July%2014%202023.pdf

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Alectra Utilities Corporation (Alectra)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd (NT Power)
- Toronto Hydro-Electric System Limited (THESL)
- Hydro One Networks Inc. (Transmission), as the lead transmitter

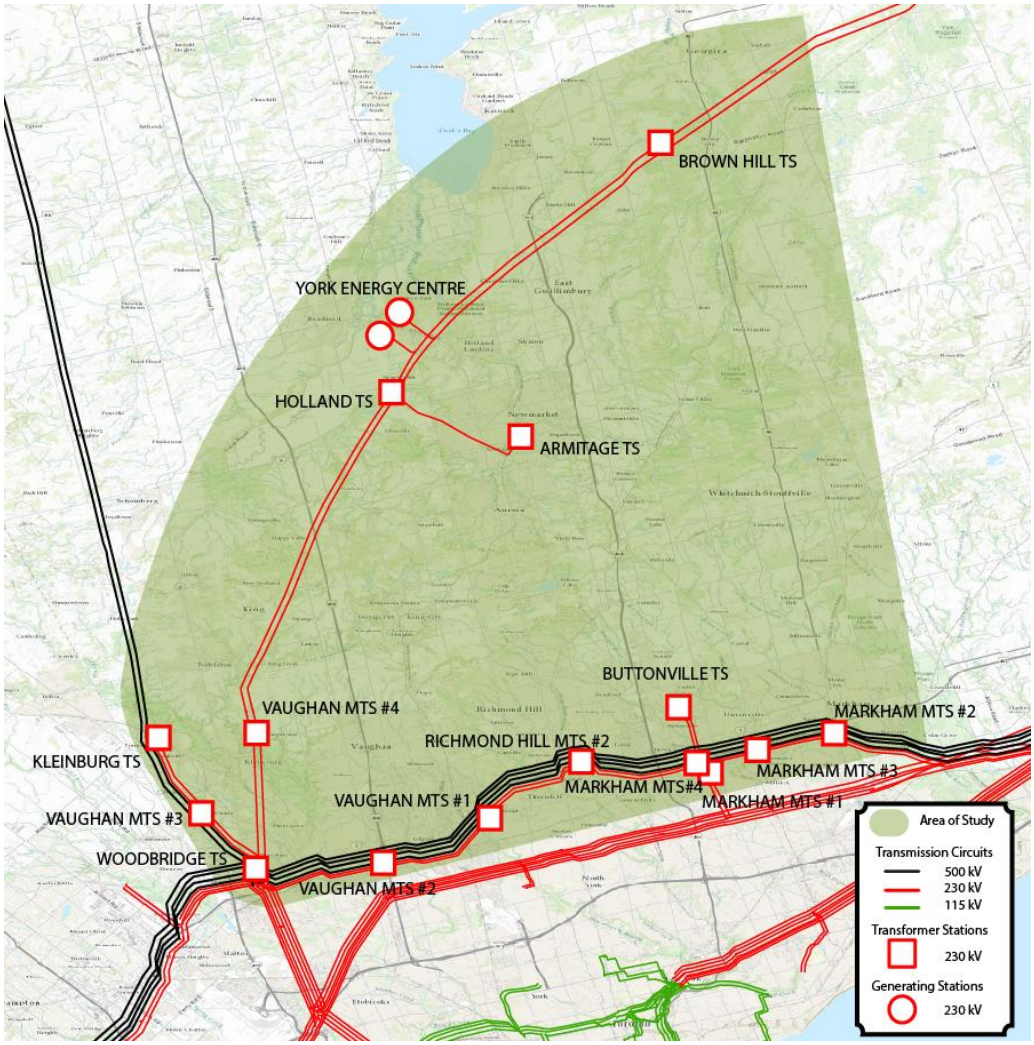
3. Categories of Needs, Analysis and Results

3.1 Overview of York Region

The GTA North Region, shown in Figure 1, roughly comprises the municipalities in the Regional municipality of York, including the Cities of Markham, Richmond Hill and Vaughan, the Towns of Aurora, East Gwillimbury, Georgina, Newmarket, Whitchurch-Stouffville, and the Township of King. Since the GTA North planning region roughly aligns with the boundaries of the Regional Municipality of York, it is commonly referred to as "York Region."

Indigenous communities including Alderville First Nation, Beausoleil First Nation, Curve Lake First Nation, Chippewas of Georgina Island First Nation, Haudenosaunee Development Institute/Hereditary Chiefs Council, Hiawatha First Nation, Kawartha Nishnawbe, Mississaugas of Scugog Island First Nation, Rama First Nation, Six Nations of the Grand River and the Mississaugas of the Credit First Nation are located in or have historical interest in the area.

Figure 1 | York Region Electricity Infrastructure



York Region is one of the fastest growing regions in Ontario. Provincial policies, including the Places to Grow Act have played a key role in facilitating and driving development in this region. Extensive urbanization in these areas over the past decade has resulted in continued increase in electricity demand. In 2022, York Region had an electricity peak demand of over 2,000 MW. Under the most recent update to the Places to Grow Act[3], significant population growth and intensification are expected to continue in York Region in the coming decades.

At the same time, many municipalities and communities in York Region are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy uses using community-based energy solutions, such as energy storage, combined heat and power and renewable energy resources.

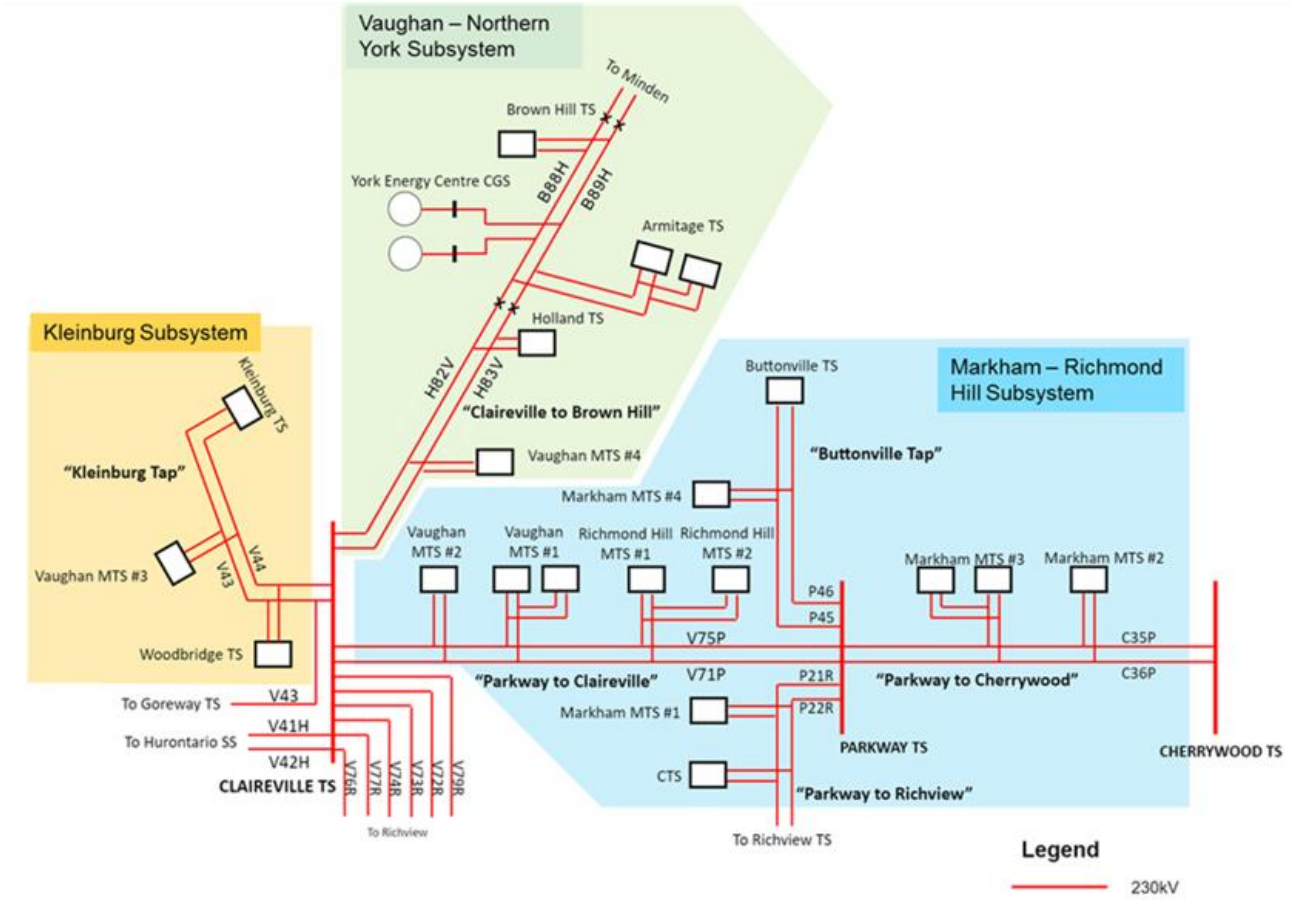
[3] A Place to Grow. Growth Plan for the Greater Golden Horseshoe. Office Consolidation 2020 https://files.ontario.ca/mmah-place-to-grow-office-consolidation-en-2020-08-28.pdf

3.1.1 Electricity System Supplying York Region

The electricity system supplying York Region consists of a high voltage (230 kV) network of transmission lines, shown in Figure 2. In addition to delivering power to this area, this network also serves as a pathway for power to flow between northern and southern Ontario as well as across the GTA.

York Energy Centre (YEC), a 393 MW natural gas-fired generating station, also provides a local source of supply within the region.

Figure 2 | Single Line Diagram of York Region



Power from the 230 kV network is delivered to communities and customers through 16 transformer stations located throughout the region that supply low-voltage (<50 kV) distribution networks and, in some cases, large individual customers. In York Region, the low-voltage distribution systems that deliver power to homes and businesses are managed and operated by four local distribution companies (LDCs): Alectra, NT Power, THESL, and Hydro One Distribution.

For the purpose of regional planning, this 230kV network is broken down into three subsystems, as shown in Figure 2:

- **Kleinburg Subsystem (V44/V43) -** This subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, as well as some areas of Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.
- **Vaughan-Northern York Subsystem (B88H/B89H, H82V/H83V)** - This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and the Chippewas of Georgina Island). YEC is connected to these 230 kV circuits. This subsystem also serves as a pathway for power to flow between northern and southern Ontario.
- **Markham-Richmond Hill Subsystem (V75P/V71P, P45/P46, P21R/P22R, C35P/C36P)** - This subsystem consists of 12 step-down transformer stations that are located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem also serves as a pathway for power to flow across the GTA along the Parkway Belt/Highway 407 transmission corridor.

3.2 Previous Regional Plans

The first cycle of the regional planning process for York Region was completed in 2016 with the publication of the Region's first Integrated Regional Resource Plan (IRRP)[4]. This plan focused on ensuring there was adequate supply to support near-term growth in the Vaughan area and on minimizing the impact of supply interruptions under major outage conditions. It recommended a number of projects to support near-term growth and to maximize the use of the existing system, including the installation of a new transformer station in Vaughan and new switching equipment at Holland transformer station and on the Parkway Belt/Highway 407 corridor.

The second cycle of regional planning was completed in 2020[5]. This IRRP mainly focused on medium and long-term system and station capacity needs. It explored multiple alternatives to increase supply capacity to York Region in the long term. As most of the needs occurred in the long-term timeframe, this plan recommended actions to preserve options and that they be revisited in the third cycle of regional planning.

[4] Available upon request to engagement@ieso.ca.

[5] 2020 York Region IRRP, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/York/York-IRRP-20200228.ashx

3.3 Needs Identified

3.3.1 Needs Identified in the Needs Assessment Phase of the Current Planning Cycle

For this third cycle of regional planning, Hydro One's Needs Assessment Report 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 York Region based on a new 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated transmission asset condition information, and updated conservation and demand management (CDM) and distributed generation (DG) forecasts provided by the IESO.

Some of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 1). However, most of the identified needs were determined to require a significant amount of planning, have a shared impact with other system assets or needs, or have the potential to be met with a combination of wires and non-wires alternatives. Therefore, the Needs Assessment concluded that these needs require further coordination (see Table 2).

Table 1 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Woodbridge TS	End of life replacement of transformer T5
2	Toubner TS	Build new station in Markham[6]
3	Vaughan MTS #6	Build new station in Vaughan[4]

[6] This new station is for a single, large, industrial customer. Upstream effects of the new station on the 230 kV network will be studied in this cycle of regional planning.

Table 2 | Needs Identified in the Needs Assessment as Requiring Coordination

Need #	Location of Need	Need Type	Need Description
1	Kleinburg	Station Capacity	Significant new load is forecast to connect at the 44kV bus in the 2023-2024 period, exceeding its capacity.
2	Markham	Station Capacity	Markham area stations are expected to exceed their capacities by 2028
3	Buttonville Tap transmission corridor	System Capacity	Circuits supplying Markham MTS #4 and Buttonville TS are expected to exceed their capacities by 2028
4	Northern York Region	Station Capacity	Northern York region is expected to reach the area's stations' capacity by 2027
5	Vaughan	Station Capacity	Vaughan area stations are expected to exceed their capacities by 2030
6	Richmond Hill	Station Capacity	Richmond Hill area stations are expected to exceed their capacities by 2032
7	Claireville to Brown Hill transmission corridor	System Capacity	Loading on the Claireville TS x Brown Hill TS corridor is expected to exceed its capacity by the early 2030s.
8	Kleinburg Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance
9	Claireville to Brown Hill transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
10	Buttonville Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.

Need #	Location of Need	Need Type	Need Description
11	Parkway to Claireville transmission corridor	Load Security	The loss of this line can result in an interruption to over 600 MW of customer load, which is more than permitted by planning criteria

3.3.2 Determination of Study Scope

The Technical Working Group (TWG) has discussed the identified needs in York 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 implications on the upstream bulk power system
- The opportunity to explore effects of a high electrification scenario.

In general, the more complex a set of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected as the preferred regional planning approach. If the needs are relatively straightforward, there are few feasible alternatives to address them, and solutions 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 TWG agreed that for each of the identified needs requiring coordination, a range of alternatives including wires and non-wires solutions should be assessed.

The TWG agreed that an IRRP should be undertaken to further assess the needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the York Region IRRP is attached in Appendix B.

The TWG has also determined that, as the identified needs span all areas of York Region, and there may be alternatives that address multiple needs across the region, there is no benefit to defining sub-regions for separate study within this IRRP process. Therefore, the recommended IRRP scope covers York Region in its entirety. Additionally, several needs were identified which do not require further coordinated planning (see Table 1), 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.

3.3.3 Pathways to Decarbonization and Powering Ontario's Growth

In December 2022, the IESO published its Pathways to Decarbonization Report[7]. 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 Greenhouse Gas (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 processes

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."

In the provincial government's "Powering Ontario's Growth" report[8], it is recognized that *"growth to date has been met by existing transmission lines, energy efficiency programs and strategically located generation assets"* and recognizes the challenge of *"future demand growth and a shift away from natural gas electricity generation"*.

Accordingly, the York Region IRRP will evaluate a scenario in which YEC, a local gas-fired generation plant, is phased out. The Pathways to Decarbonization report had previously identified that this could not be achieved within the timelines considered by the 2035 Moratorium scenario, so the IRRP will include identification of required system investments needed to accommodate this phase-out, and an estimated timeline for how quickly this could be accomplished.

Consideration will also be given to a separate "high electrification" demand forecast that would examine and evaluate the needs that arise on the electricity system in York Region under a more aggressive decarbonisation scenario and provide recommendations on near-term actions to facilitate this transition.

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[7] Pathways to Decarbonization, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.ashx

[8] Powering Ontario's Growth, Province of Ontario. https://www.ontario.ca/page/powering-ontarios-growth

A summary of planning scenarios for inclusion in the IRRP is provided in Table 3, below:

Table 3 | Summary of Planning Scenarios

Scenario	Demand Forecast	Generation Assumptions	Notes
1a	Basecase	Continued operation of York Energy Centre	Basecase Scenario. Needs and recommendations will form the main deliverables of the IRRP
1b	Basecase	Phase out of York Energy Centre	Identify incremental needs and recommended options resulting from York Energy Centre phase out
2	High Electrification	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from transition to net zero energy system

3.3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook[9] (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 York Region, its findings (i.e. needs and recommended solutions) will be coordinated with the York Region IRRP, and vice-versa.

[9] 2022 Annual Planning Outlook. IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/2022-Annual-Planning-Outlook.ashx

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- An IRRP is to be undertaken for York Region;
- The IRRP Working Group will include the IESO, Alectra, NT Power, Hydro One Distribution, and Hydro One Transmission. Other LDCs in the region will be informed of any needs or solutions that may affect their facilities or customers;
- The IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- Given the significant scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required.

An IRRP was recommended on the basis of the scale of load growth anticipated, potential for diverse types of solutions (including wires and non wires), and long term uncertainty associated with regional development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

All IRRPs include opportunities for engagement with local communities and stakeholders, including 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 other similar products. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the York Region 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
LMC	Load Meeting Capability
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 – York Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

The GTA North Region (York Region) is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) Regional Planning Process. Since the geographical boundaries of GTA North Region roughly encompass the Regional Municipality of York, this planning region is often referred to as York Region.

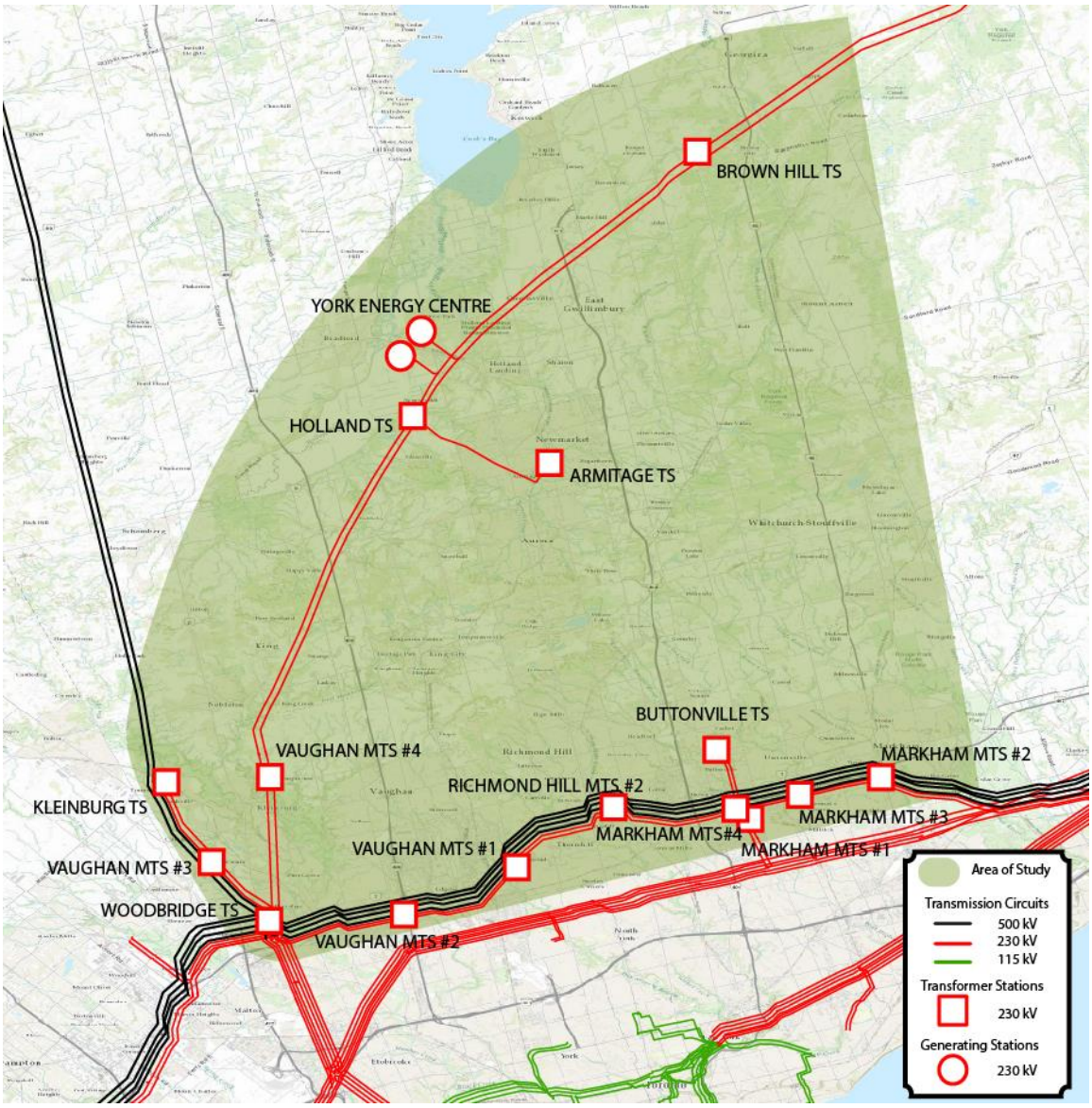
These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for York Region.

1.1 GTA North Region (York Region)

York Region, shown in Figure 3, roughly comprises the municipalities in the Regional municipality of York, including the Cities of Markham, Richmond Hill and Vaughan, the Towns of Aurora, East Gwillimbury, Georgina, Newmarket, Whitchurch-Stouffville, and the Township of King.

Indigenous communities including Alderville First Nation, Beausoleil First Nation, Curve Lake First Nation, Chippewas of Georgina Island First Nation, Haudenosaunee Development Institute/Hereditary Chiefs Council, Hiawatha First Nation, Kawartha Nishnawbe, Mississaugas of Scugog Island First Nation, Rama First Nation, Six Nations of the Grand River and the Mississaugas of the Credit First Nation are located in or have historical interest in the area.

Figure 3 | York Region Electricity Infrastructure



1.2 Background

In July 2023, Hydro One completed the Needs Assessment Report[10] for York Region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP was recommended on the basis of the scale of load growth anticipated, potential for diverse types of solutions (including wires and non wires), and long term uncertainty associated with regional 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 that provides electricity supply to York Region over the next 20 years.
2. Account for 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 identified needs.
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, preparatory 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 York Region. The plan is a joint initiative involving the IESO, Alectra, NT Power, Hydro One Distribution, and Hydro One Transmission[11] 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 York Region IRRP includes the following needs, that were identified in the Needs Assessment as requiring coordination:

[10] Hydro One: GTA North Needs Assessment Report, July 2023. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/gtanorth/Documents/GTA%20North%20Region%20NA%20Report%20Final%20July%2014%202023.pdf

[11] A small portion of Toronto Hydro's service area is also supplied by feeders from some stations in York Region. Toronto Hydro 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.

Table 4 | Needs Identified in the Needs Assessment as Requiring Coordination

Need #	Location of Need	Need Type	Need Description
1	Kleinburg	Station Capacity	Significant new load is forecast to connect at the 44kV bus in the 2023-2024 period, exceeding its capacity.
2	Markham	Station Capacity	Markham area stations are expected to exceed their capacities by 2028
3	Buttonville Tap transmission corridor	System Capacity	Circuits supplying Markham MTS #4 and Buttonville TS are expected to exceed their capacities by 2028
4	Northern York Region	Station Capacity	Northern York region is expected to reach the area's stations' capacity by 2027
5	Vaughan	Station Capacity	Vaughan area stations are expected to exceed their capacities by 2030
6	Richmond Hill	Station Capacity	Richmond Hill area stations are expected to exceed their capacities by 2032
7	Claireville to Brown Hill transmission corridor	System Capacity	Loading on the Claireville TS x Brown Hill TS corridor is expected to exceed its capacity by the early 2030s.
8	Kleinburg Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance
9	Claireville to Brown Hill transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.
10	Buttonville Tap transmission corridor	Load Restoration	Inability to restore customer loads within the timelines established by planning criteria following a major system disturbance.

Need #	Location of Need	Need Type	Need Description
11	Parkway to Claireville transmission corridor	Load Security	The loss of this line can result in an interruption to over 600 MW of customer load, which is more than permitted by planning criteria

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 Pathways to Decarbonization and Powering Ontario's Growth

In December 2022, the IESO published its Pathways to Decarbonization Report[12]. 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 Greenhouse Gas (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 processes

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."

In the provincial government's "Powering Ontario's Growth" report[13], it is recognized that *"growth to date has been met by existing transmission lines, energy efficiency programs and strategically located generation assets"* and recognizes the challenge of *"future demand growth and a shift away from natural gas electricity generation"*.

[12] Pathways to Decarbonization, IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.ashx

[13] Powering Ontario's Growth, Province of Ontario. https://www.ontario.ca/page/powering-ontarios-growth

Accordingly, the York Region IRRP will evaluate a scenario in which YEC, a local gas-fired generation plant, is phased out. The Pathways to Decarbonization report had previously identified that this could not be achieved within the timelines considered by the 2035 Moratorium scenario, so the IRRP will include identification of required system investments needed to accommodate this phase-out, and an estimated timeline for how quickly this could be accomplished.

Consideration will also be given to a separate "high electrification" demand forecast that would examine and evaluate the needs that arise on the electricity system in York Region under a more aggressive decarbonisation scenario and provide recommendations on near-term actions to facilitate this transition.

A summary of planning scenarios for inclusion in the IRRP is provided in Table 5, below:

Table 5 | Summary of Planning Scenarios

Scenario	Demand Forecast	Generation Assumptions	Notes
1a	Basecase	Continued operation of York Energy Centre	Basecase Scenario. Needs and recommendations will form the main deliverables of the IRRP
1b	Basecase	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from York Energy Centre phase out
2	High Electrification	Phase out of York Energy Centre	Identify incremental needs and recommend options resulting from transition to net zero energy system

3.3 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook[14] (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 York Region, its findings (i.e. needs and recommended solutions) will be coordinated with the York Region IRRP, and vice-versa.

[14] 2022 Annual Planning Outlook. IESO. https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/2022-Annual-Planning-Outlook.ashx

4. Activities

The IRRP process will consist of the activities listed below. The activities and anticipated timelines are summarized in Table 6 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 scenarios 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 two electricity demand forecasts for York Region:
    a. The first, a "business as usual" forecast, should account for all municipalities' and LDCs' committed long-term policy goals and plans, taking into account local and provincial policy goals, commitments, and climate change action plans. This is the primary forecast which will be used to identify needs, preferred options, and recommendations.
    b. The second, a high electrification forecast, will represent the impacts of a net zero energy system by 2050, consistent with the Pathways to Decarbonization report. This forecast will be used to evaluate the incremental needs and develop recommendations to accommodate a net zero target.
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 and the YEC phase out 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 York Region 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 York Region 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.
        i. This will include studying a scenario where transmission-connected gas generation is phased out per the timelines in the Pathways to Decarbonization report.
    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 5 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
    - Municipal policies with an impact on electricity usage
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Yonge subway extension), and transit electrification (e.g. GO train electrification)
    - Pathways to Decarbonization and Powering Ontario's Growth reports

- 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)*
- Alectra Utilities Corporation (Alectra)
- Hydro One Networks Inc. (Distribution)
- Newmarket-Tay Power Distribution Ltd
- Hydro One Networks Inc. (Transmission)

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 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 York Region 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 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 6 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	October 2023
2. Develop the planning forecast scenarios for the region		Long-term planning forecast scenarios	Q4 2023 – Q1 2024
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	LDCs		
d. Establish existing, committed, and potential DG	IESO, LDCs		
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	LDCs / Hydro One Transmission	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	LDCs, 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	Q2 – Q3 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q3 – Q4 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the load meeting capability (LMC) of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and LDCs		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and LDCs		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and LDCs		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and LDCs		
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 Q4 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 LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and LDCs		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and LDCs		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and LDCs		
8. Develop 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 2025
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	April 2025

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EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX E
GTA NORTH -
INTEGRATED REGIONAL RESOURCE PLAN

GTA North (York Region) Integrated Regional Resource Plan

October 10, 2025

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-Level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
eDSM	Electricity Demand Side Management
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

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Appendix A. Overview of the Regional Planning Process

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Executive Summary

The GTA North (York Region) Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the GTA North Region over a 20-year period, from 2024 to 2043. The GTA North Region is located in southern Ontario and is defined by electrical infrastructure boundaries, not municipal, yet roughly includes the municipalities of Aurora, East Gwillimbury, Georgina, King, Markham, Newmarket, Richmond Hill, Vaughan, Whitchurch-Stouffville, and parts of Simcoe County, including Bradford-West Gwillimbury. Because these municipalities primarily fall within York Region, the terms "GTA North Region" and "York Region" are used interchangeably in this study.

For the purposes of this IRRP, the region is often divided into four electrical subsystems: Northern York, Kleinburg, Southern Vaughan-Richmond Hill, and Markham and Area. These subsystems reflect the configuration of the transmission system and the location of major step-down transformer stations and other points of system supply. The IRRP focuses on identifying and addressing electricity needs in each of these subsystems, while also coordinating with broader bulk system planning and other coordinated planning efforts, including regional planning in GTA West and South Georgian Bay-Muskoka, and corridor identification and preservation initiatives.

The Region of York is growing rapidly, with a population of 1.26 million in 2024, and is expected to grow to over 2 million by 2051. Existing infrastructure supplying York Region is insufficient to meet anticipated growth in electricity demand. Some sections of northern York in particular are already experiencing challenges in connecting new customer loads. Investing in new transmission infrastructure would have a positive impact on the region, especially increasing the ability for new loads to connect, and maintaining the reliability of existing customers throughout York Region.

The electricity demand forecast for York Region shows significant growth over the planning horizon, driven by residential intensification, commercial development (including large energy-intensive customers), and electrification trends (such as electric vehicles and heat pumps). Summer peak demand is expected to nearly double by 2043, while winter peaks could potentially triple depending on the pace of electrification. While the region has historically been summer-peaking, winter peaks could become more limiting by the early-2030s. Given the uncertainty associated with long-term growth forecasts, particularly with respect to winter peaks that rely on new customer behaviour and technological availability, this study has placed a greater emphasis on managing uncertainty and risk in demand forecasts. In practice, only summer peak forecasts have been used to make recommendations which require immediate action. For longer term needs, dates associated with summer peaks have been the primary driver for planning during this cycle. The impacts of higher potential winter peaks have been considered and will continue to be monitored through the Annual Working Group to determine the need to trigger long term system reinforcements.

To identify near-, medium-, and long-term needs, the Technical Working Group assessed station capacity, supply capacity, reliability, and load security needs across the region. A combination of wires and non-wires solutions were evaluated, with a number of recommendations made to address near-term needs. Options for addressing longer-term needs are also proposed, but do not yet require action, except to preserve long-term viability of the solution options. Non-wires alternatives (NWAs) such as targeted electricity demand-side management (eDSM) and distributed energy resources

(DERs) have been recommended to help manage near-term reliability risks and potentially defer longer-term infrastructure requirements.

Additional consideration has also been given to long term impacts of reduced reliance on York Energy Centre, following its contract expiry in 2035. This includes evaluation of the impact of the loss of supply on the local system, and potential solutions which may need to be pursued if this facility is no longer available.

The study has also considered points of coordination with an ongoing bulk planning initiative, the South and Central Bulk Plan, which is studying bulk system needs and potential upgrades with a notional 2035 focus. A second, longer-term bulk planning study, expected to be initiated in 2026 with a focus on bulk system needs into the 2040s, will similarly consider potential impact of bulk enhancements on regional supply. Both studies have the potential to affect longer-term needs and feasibility of solutions available to in the area, particularly for needs emerging post 2035 or 2040.

Engagement was a key component of this IRRP. The IESO engaged with municipalities, Indigenous communities, stakeholders, and the public throughout the planning process. Feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

The Technical Working Group will continue to monitor growth, electrification trends, and large customer connections across the region. The group will meet regularly to track progress, assess changing conditions, and update the plan as needed. If underlying assumptions change significantly, the IRRP may be amended, or a new planning cycle initiated ahead of the standard five-year schedule mandated by the Ontario Energy Board.

Summary of Recommendations

Near-term recommendations emerging from this plan will provide increased station and system capacity across the region and allow for anticipated load growth to be reliably met into the 2030s. Immediate action is recommended to implement the following:

Table 1| Summary of Near-Term Recommendations

Project	Need	Need Timing	Expected In-Service
Additional targeted incremental eDSM to manage demand and ease pressure on the system	Station and Supply Capacity in Northern York, Markham, Richmond Hill, and Whitchurch-Stouffville	Ongoing	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity in Northern York	Immediate	2026
Develop Northern York TS #1	Station Capacity in Northern York	Immediate	2030
Develop Markham MTS #5	Station Capacity in Markham	2029	2028/2029

Project	Need	Need Timing	Expected In-Service
Develop Richmond Hill MTS #3	Station Capacity in Richmond Hill	2030	2030
Install new breakers along Parkway to Claireville corridor	Load Security in Vaughan and Richmond Hill	Immediate	2028/2029
Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5 (in phases)	Supply Capacity in Markham	2029	2029
Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line)	Supply Capacity in Northern York	2030	2031/2032
Develop/preserve viability of long-term capacity options through corridor identification and preservation initiatives	Station and Supply Capacity	Ongoing	Ongoing

The Technical Working Group will continue to monitor and may recommend action based on revised forecasts and demand growth for these medium- to long-term needs and recommendations:

Table 2| Summary of Medium- to Long Term Recommendations

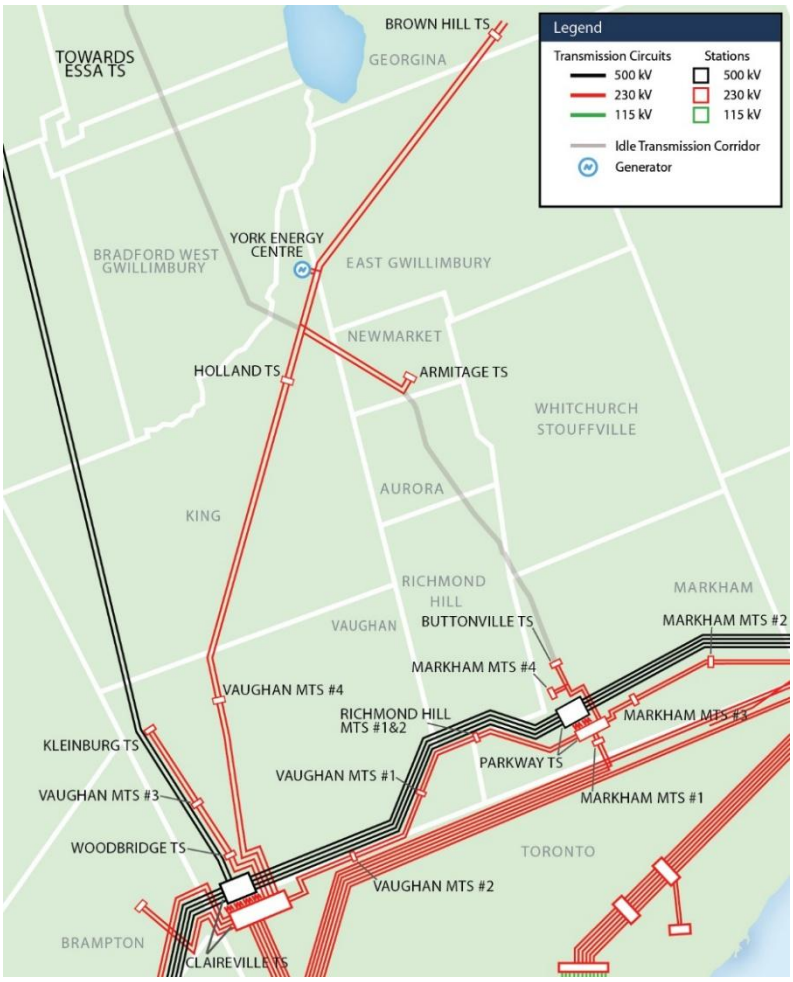
Project	Need	Need Timing	Expected In-Service
Develop Vaughan MTS #5	Station Capacity in Vaughan	2033	2033
Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6	Station Capacity in Markham, Richmond Hill, and Whitchurch-Stouffville	2034	2034
Monitor future electricity needs and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station	Station and Supply Capacity in Northern York	2035	2035

1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses electricity needs for the GTA North Regional Planning area ("GTA North" or "York Region") between 2025 and 2043. This report was prepared by the Independent Electricity System Operator (IESO) on behalf of the York Region Technical Working Group comprising the IESO, Alectra Utilities Corporation (Alectra), Newmarket-Tay Power Distribution Ltd. (NT Power), Hydro One Networks Inc. (Hydro One Distribution), and Hydro One Networks Inc. (Hydro One Transmission).

In Ontario, planning to meet the electrical supply and reliability needs of a local 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 GTA North Region, shown in Figure 1, roughly corresponds with the municipal boundaries of York Region. For the purposes of this plan, GTA North and York Region can be used interchangeably.

Figure 1| Overview of the GTA North (York) Region



Development of the GTA North (York Region) IRRP was initiated in October 2023, following the publication of the Needs Assessment report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment identified the area's needs should be further assessed through an IRRP. The Technical Working Group was then formed to gather data, identify near-, medium-, and long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2
- The process and methodology used to develop the plan are discussed in Section 3
- The background for electricity planning in the region and the study scope is discussed in Section 4
- The development of the demand forecast, including electricity Demand Side Management (eDSM) and distributed generation assumptions, are described in Section 5
- Electricity needs in the region are presented in Section 6
- Alternatives and recommendations for meeting needs are addressed in Section 7
- Linkages to the South and Central Bulk Study is outlined Section 8
- A summary of engagement activities is provided in Section 9, and
- The conclusion is provided in Section 10.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of York Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of different options to address the region's needs in consideration of reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from communities and stakeholders.

2.1 Status of Projects from Previous IRRP Cycles

Following the previous cycle of regional planning, which concluded with the 2nd Cycle RIP report, several projects were recommended that have now been completed or are presently underway. The status of these projects is summarized in Table 3.

Table 3| Needs Identified in the Previous Cycle with Revised In-Service Date

Project	Need	Expected In-Service
Collect Information on future NWAs and opportunities in York Region to inform the next IRRP	Station and Supply Capacity	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity	2026
Develop Markham MTS #5	Station Capacity	Expected in Service Date in 2028/2029
Reconductor Circuit P45/46 from Parkway to Markham MTS #4	Supply Capacity	Expected in Service Date in 2029
Develop Northern York TS #1	Station Capacity	Expected in Service Date in 2030
Develop/Preserve Viability of Long-term Capacity Options	Station and Supply Capacity	Ongoing

2.2 Plan for Near-Term Needs (2026-2030)

The near-term plan consists of several recommendations to enable load growth and maintain reliability. Many of these needs are immediate, and based on today's peak demand, while others are based on strong anticipated load growth over the next five years. Implementation should be initiated immediately to ensure required in service dates can be met.

Additional targeted incremental eDSM to manage demand and ease pressure on the system. As an interim measure, eDSM may be considered to manage shortfalls where the infrastructure solution is not expected to be in service in time to meet existing or anticipated needs. eDSM also has the potential to defer the need for additional infrastructure investments anticipated to be required in the medium- to long-term.

Reconfigure York Energy Centre (YEC) Station Service Supply. Upgrading the station supply arrangement for YEC would allow for this facility to remain operational for a wider range of transmission outage conditions. This would have an immediate reliability benefit for local customers and improve the ability to supply load in the area. Cost and in-service timelines will be evaluated following more detailed site-specific analysis.

Develop Northern York TS #1. The need for additional station capacity in Northern York is immediate. Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Markham TS #5. The need for additional station capacity for Markham area was identified in the previous IRRP and reaffirmed with the latest demand forecast to be required by 2029. Alectra has identified a suitable location for the next Markham MTS #5 near the existing Buttonville TS on the P45/46 circuits, and this project is currently under development. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Richmond Hill MTS #3. The need for additional station capacity in Richmond Hill is expected by 2030, triggered by new development applications in proximity to the planned Yonge subway extension. Alectra has identified a suitable location for the next Richmond Hill MTS #3, and this project is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. Typical development costs for these types of stations, including real estate, are generally $60 million.

Install new breakers along Parkway to Claireville corridor. The existing V71/75P transmission corridor between Claireville TS and Parkway TS are currently loaded at over 600 MW during summer peak, with demand having exceeded 730 MW in 2025. This violates applicable security criteria, and loading is expected to worsen following the connection and loading of Richmond Hill MTS #3 in 2030 and Vaughan MTS #5 in 2033. Estimated costs are $30-35 million.

Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5. Connection and loading of the new Markham MTS #5 is expected to trigger thermal needs on P45/46. Reconductoring of the existing lines will enable full loading of this station, which comes into service in 2028/2029. The cost of reconductoring the entire facility is estimated at $14, though there are opportunities to carry out this work on a phased basis.

Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line). A new, six-km double circuit 230kV transmission line is proposed adjacent to the planned Highway 413 in Vaughan. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4 along the H82/83V circuits. It would enable the connection and full loading of the next Northern York TS #1 step down station. The cost of this transmission is estimated at $40 million, with an estimated in-service date of 2031-2032. Operation of this facility will require coordination with bulk system upgrades at Kleinburg TS, as under development in the ongoing Bulk System Plan for South & Central Ontario (see Section 8).

2.3 Plan for Medium to Long-Term Needs (2031-2040)

While most recommended actions from this plan are concerned with addressing near term needs (within the next five years), the sections below outline potential medium- to long-term recommendations beyond that horizon. These recommendations, including their targeted in-service dates, are subject to change and will be continuously re-evaluated as planning progresses, based on new information and actual load growth. Early identification of these plans is important to ensure ongoing engagement with potentially affected communities, coordination with broader regional and bulk system planning, and to enable timely implementation when required. It is recommended that the Working Group finalize a long-term adaptive pathway[1] for each subsystem following the completion of this cycle of regional planning.

Develop Vaughan MTS #5. The need for additional station capacity in downtown Vaughan is expected in 2033, triggered by intensified development in the Vaughan Metropolitan Centre (VMC). Alectra is in the process of evaluating potential locations for the next Vaughan MTS #5. The ultimate connection point will likely be along the V71/75V circuits, between the existing Vaughan MTS #1 and the Richmond Hill MTSs. Typical development costs for these types of stations, including real estate, are generally $60 million.

Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6. The need for additional station capacity in the areas of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville is expected to trigger the need for the development of two new step-down stations, Markham MTS #6 and Northern York TS #2, in the mid 2030s. In order to supply these stations, an approximate 7-km extension of the existing P45/46 circuits is recommended into northern Markham, along an existing, idle transmission right of way. Costs of this transmission could range from $45 million to $175 million, depending on the technology selected during the project scoping and environmental assessment process (e.g., overhead versus underground). This solution would also require development of a new transmission tap to remove Markham MTS #4 from P45/46 supply. The preferred location to supply this station would be the C35/36P circuits, with a likely additional cost of $9 million.

[1] Adaptation pathways are sequences of actions, which can be implemented progressively, depending on future dynamics and uncertain variables.

Monitor future electricity needs in northern York and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station. Longer-term station capacity needs will likely trigger additional transmission upgrades in Northern York including, at a minimum, a new switching station in the vicinity of Holland Marsh junction to coincide with the development of Northern York TS #3 in the mid 2030s. Switching stations typically cost $200-250 million, though it would also have bulk system benefits. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of additional infrastructure in the area. The exact nature of options and recommendations will continue to be evaluated and will be informed by ongoing bulk system studies.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a local area – defined by common electricity supply infrastructure – over the near, medium, and long term periods. The result is a plan aimed at ensuring cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. 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 and determines if there are electricity needs requiring regional coordination;
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 proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. The IESO also carries out bulk system planning and Local Distribution Companies are responsible for distribution system planning. There are inherent linkages in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

3.2 GTA North IRRP Development

The process to develop the GTA North (York) Region IRRP was initiated in October 2023, following the publications of the Needs Assessment Report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment recommended that the needs identified for GTA North Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4 Background and Study Scope

This is the third cycle of regional planning for the GTA North (York) Region. This Region is located in southern Ontario and includes all or part of the following cities, towns and townships:

Aurora	Bradford West Gwillimbury	East Gwillimbury	Georgina
King	Markham	Newmarket	Richmond Hill
Simcoe County	Vaughan	Whitchurch-Stouffville	

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries. This Region also includes several Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use:

Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Métis Nation of Ontario.

Following a Needs Assessment in March 2018 and a Scoping Assessment in August 2018, an IRRP and subsequent RIP were initiated and published in February 2020 and October 2020, concluding the second planning cycle for the Region.

This IRRP develops and recommends options to meet the electricity needs of the GTA North (York) Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, eDSM, distributed energy resources (DERs) transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The GTA North (York) Region covers a large portion of the transmission system in both the Toronto and Essa IESO electrical zones. As all the transmission facilities in the region are included in the scope of this study, it has often been broken up into four subsystems:

- **Northern York Subsystem (B88H/B89H, H82V/H83V) Subsystem**

  This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and the Chippewas of Georgina Island). York Energy Centre is connected to these 230 kV circuits. This subsystem also serves as a pathway for power to flow between northern and southern Ontario.

- **Kleinburg (V44/V43) Subsystem**

  This subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, as well as some areas of Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.

- **Southern Vaughan-Richmond Hill Subsystem (V75P/V71P, P21R/P22R)**

  This subsystem consists of four step-down transformer stations that supply the southern parts of urban communities in the Markham, Richmond Hill and Vaughan areas.

- **Markham and Area Subsystem (P45/P46, C35P/C36P)**

  This subsystem consists of 6 step-down transformer stations that are located in urban communities primarily in the Markham. This subsystem also serves as a pathway for power to flow across the GTA along the Parkway Belt/Highway 407 transmission corridor.

The Northern York subsystem consists of the following stations:

Brown Hill TS Armitage TS Holland TS Vaughan MTS #4

The Kleinburg subsystem consists of the following stations:

Kleinburg TS Vaughan MTS #3 Woodbridge TS

The Southern Vaughan-Richmond Hill subsystem consists of the following stations:

Vaughan MTS #1 Vaughan MTS #2 Richmond Hill MTS #1 Richmond Hill MTS #2

The Markham and Area subsystem consists of the following stations:

Buttonville TS Markham MTS #1 Markham MTS #2 Markham MTS #3 Markham MTS #4

The GTA North (York) IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over the 2024-2043 timeframe (as described in Section 5);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and the performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying the criteria and standards from ORTAC, NPCC, and NERC.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and LDCs.

- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near-, medium-, and long-term needs; and communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the GTA North (York) Region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of eDSM and DG. The LDCs in the region provided both a winter and summer 20-year forecast that incorporates organic growth and growth associated with drivers like electrification (e.g., heating load and electric vehicles).

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum.

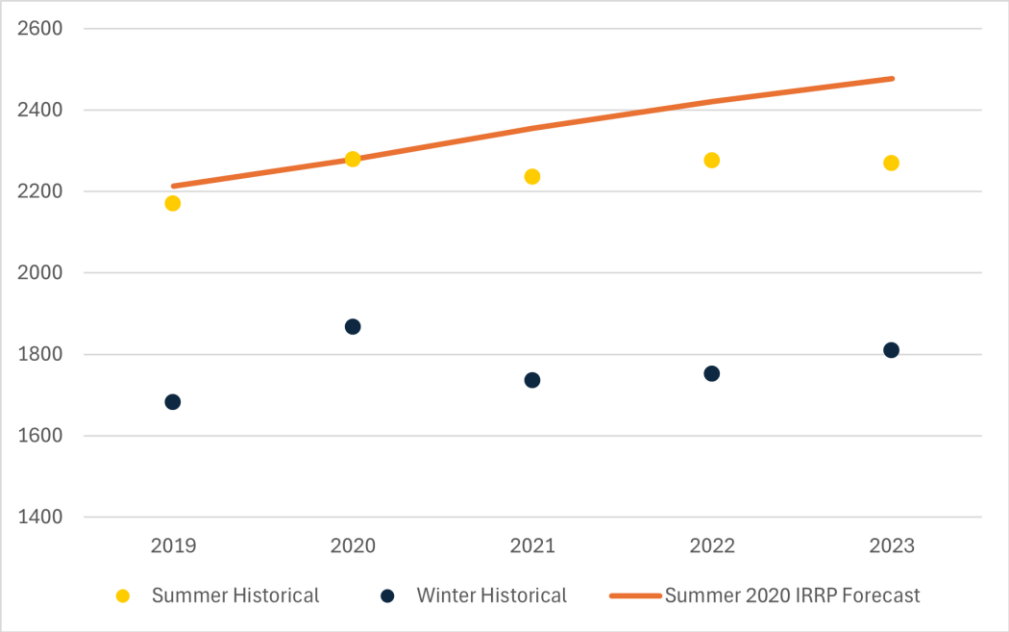
The regional planning process also considered non-coincident peaks which refers to each station's individual peak, regardless of whether these peaks occur at different times. Non-coincident peaks are used to understand the potential needs of the stations.

5.1 Historical Demand

Peak electricity demand within GTA North has historically occurred in the summer season. Figure 2, below, shows both the winter and summer coincident gross normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for the GTA North region. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand, as they are more appropriate for evaluating growth trends. For context, Figure 2 also includes the summer peak demand forecast for the same years from the 2020 IRRP.

The gross weather-corrected demand for the GTA North region has averaged 2,245 MW in the summer and 1769 MW in the winter over the last five years preceding the IRRP start date (2019-2023).

Figure 2| Summer and Winter Historical Weather-Corrected Coincident Peak

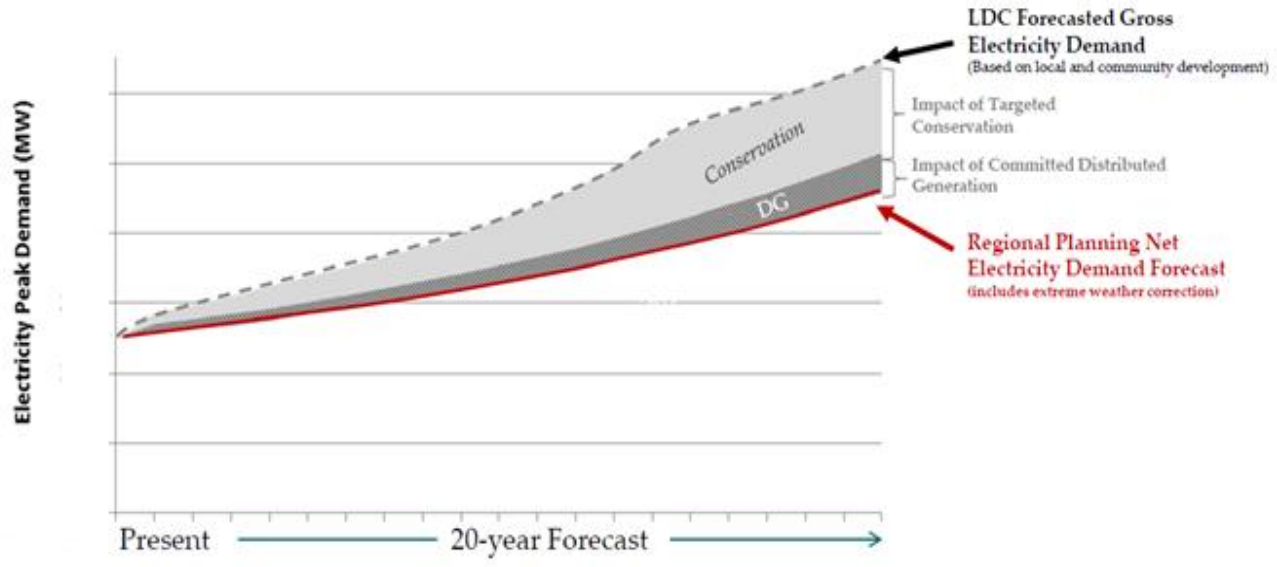


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast is illustrated in Figure 3. A gross demand forecast, which assumes the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), was developed by the LDCs. This forecast was then adjusted to reflect the expected impact of extreme weather conditions to produce a reference forecast for planning assessments. Extreme weather conditions, as defined by the IESO, assume the worst observed weather over the previous 30 years. The forecast was then modified to reflect the expected peak demand impacts of provincial demand side management programs and DG contracted through previous provincial programs, such as renewable Feed-In Tariff (FIT) and microFIT standard offer programs. This net demand forecast was used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The load forecast methodology is also informed by the Load Forecast Guideline for regional planning, which was formalized by the OEB's Regional Planning Process Advisory Group.

Figure 3| Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

LDCs are responsible for preparing the gross demand forecast as they have the most direct understanding of future local demand growth and drivers, informed by involvement with their customers, connection applicants, municipalities and the communities which they serve. Gross demand forecasts were prepared by the participating LDCs at the station level, or at the station bus level for multi-bus stations. The gross demand forecast generally accounts for increases in demand from new or intensified development, plus known connection applications. In addition, when producing the gross demand forecast, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). More details are provided in Appendix B.

The LDCs' forecasts considered the appropriate municipal plans for their service territories. The LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural conservation), but not for the impact of future DG or new demand side management activities (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions (e.g. median weather, expected 1 in 2 years), and provided station level loading at the time of the regional peak.

The IESO typically carries out demand forecasting at the provincial level, which is more applicable for bulk system analysis than regional. More details on the LDC load forecast assumptions can be found in Appendix B.

5.4 Contribution of Electricity demand Side Management

Electricity demand side management (eDSM, formerly Conservation and Demand Management or CDM) is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak demand and has become an integral component of provincial and regional planning. Electricity savings from demand side management is achieved

through a mix of efficiency codes and standards, as well as eDSM program-related activities. These approaches complement each other to maximize results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (e.g., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities was based on the IESO's 2024 Annual Planning Outlook eDSM savings forecast informed by the then current 2021-2024 Conservation and Demand Management (CDM) Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs assumed to be consistent with 2021-2024 framework savings levels. Through the 2021-2024 CDM Framework the IESO centrally delivered programs under the Save on Energy brand s to serve business and residential customers, as well as Indigenous communities. Following finalization of the IRRP's demand forecast, the Ontario government provided the IESO with the directive for the 2025-2036 Electricity Demand Side Management Framework, which expands the scale and scope of the Save on Energy programs, including launch of the Home Renovations Saving program for residential customers and new incentives for rooftop solar for both residential and business customers. Higher savings targets under the new framework may impact the timing or reduce the magnitude of identified needs.

Figure 4 and Figure 5 show the estimated total yearly reduction to the demand forecast due to demand side management (from codes, standards, and eDSM programs). Additional details are provided in Appendix B.

Figure 4| Summer Peak Demand Reduction Due to Demand Side Management

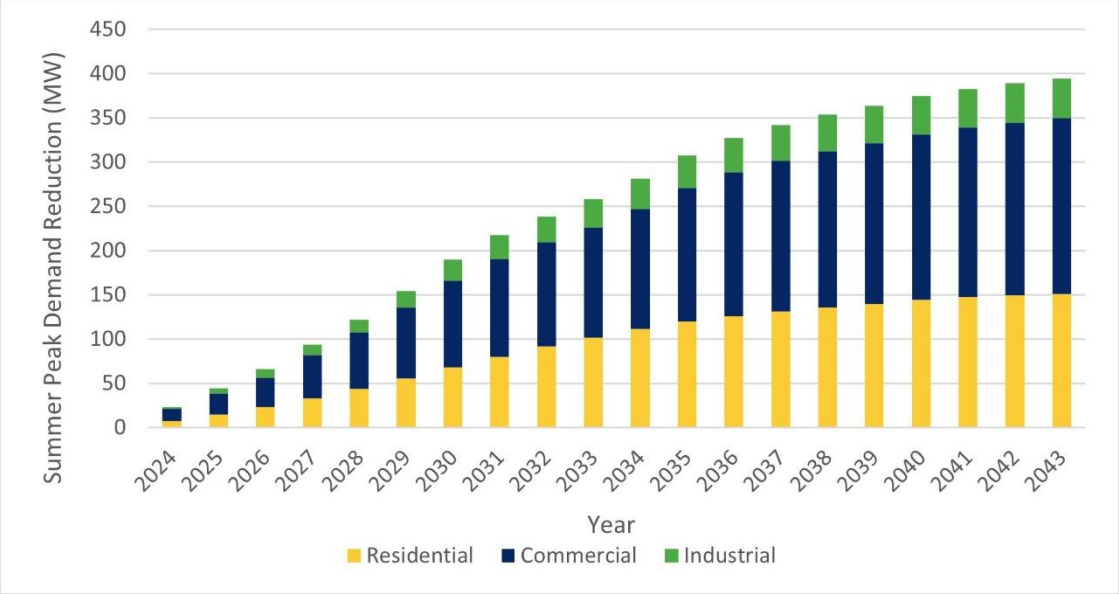
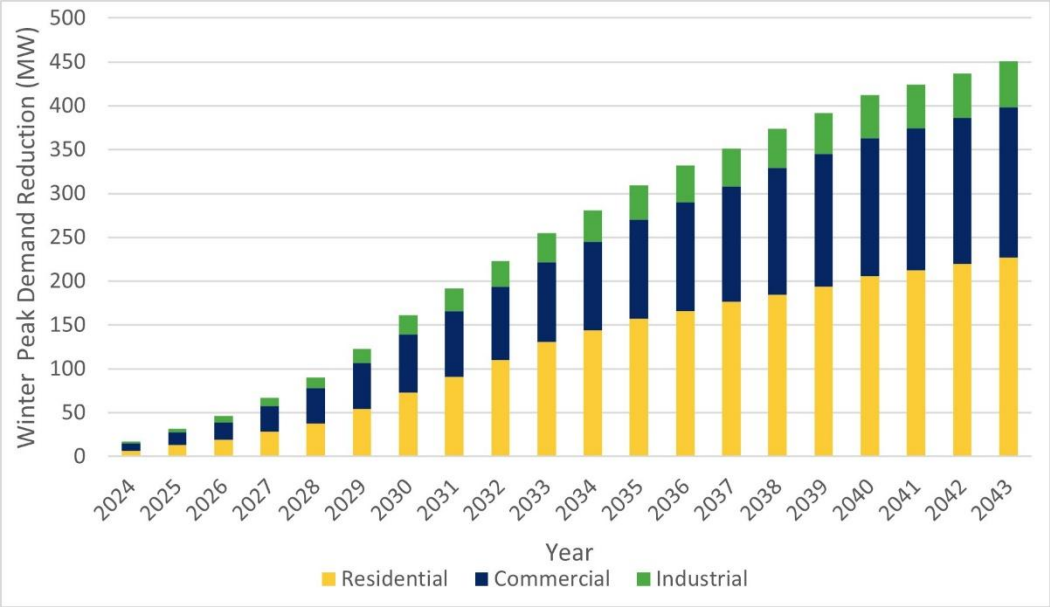


Figure 5| Winter Peak Demand Reduction Due to Demand Side Management

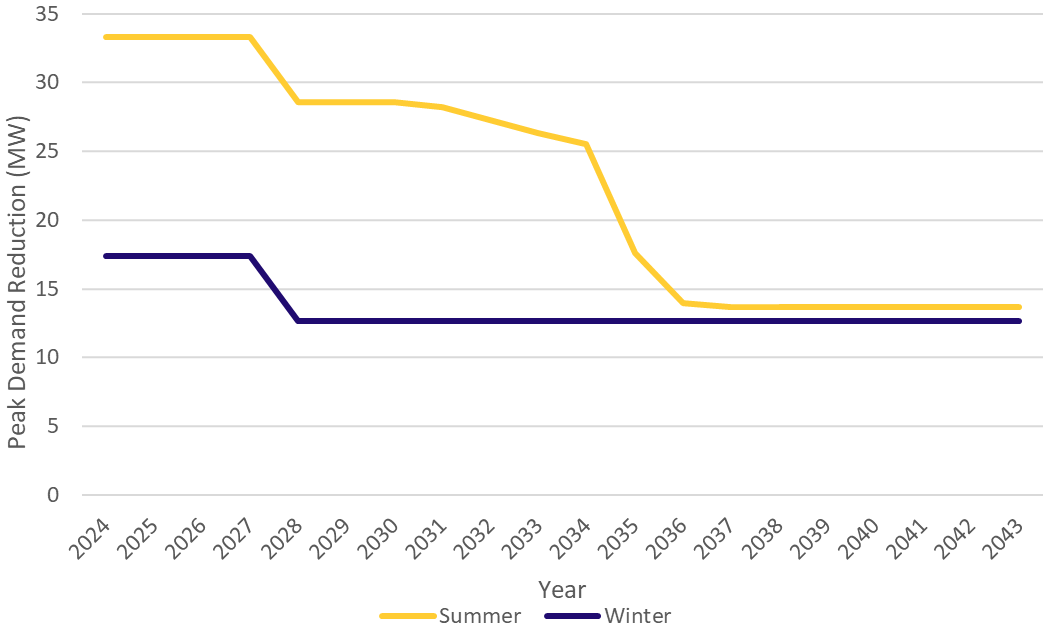


5.5 Contribution of Distributed Energy Resources to the Forecast

In addition to demand side management programs (which can include behind the meter DG), DG is forecasted to offset peak-demand requirements. The introduction of Ontario's FIT and microFIT Programs increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in Appendix B. The total contracted installed DG capacity in the GTA North Region is composed of a mix of renewable and non-renewable sources.

Figure 6 shows the estimated impact of DG on the GTA North Region demand forecast. The forecasted impact declines as existing FIT and microFIT contracted facilities reach the end of their contract terms throughout the late 2020s and into the mid-2030s.

Figure 6| Peak Demand Reduction Due to Distributed Energy Resources



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs driven by more than one station.

The planning forecast is produced from two main steps: adjusting for extreme weather and converting to a net forecast.

The first step is to adjust the coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather. Two separate weather scenarios were prepared; one for extreme summer conditions, and one for extreme winter conditions.

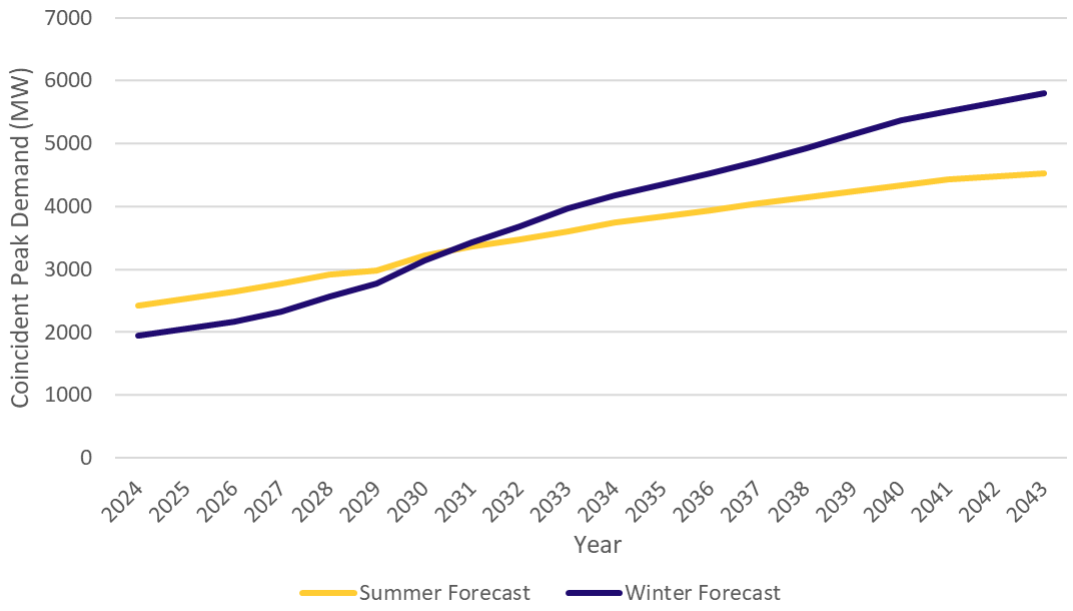
Historically, York Region has experienced its highest loading conditions during summer months, driven by air conditioning loads. This is consistent with overall provincial peak conditions, which often occur on the same day and on similar, late afternoon hours as York Region. However, the expected adoption of electrified heating, namely heat-pumps, is forecast to significantly increase winter demand over the coming decades. While there is uncertainty around the rate of uptake, technology types, and operational decisions, a winter demand forecast was also developed to study the impact of higher winter peak growth rates. Both summer and winter peak forecasts were considered in this IRRP.

The last step is to adjust the resulting coincident gross extreme weather forecast for the impact of DG and demand side management. This is done by subtracting the forecasted DG and electricity demand side management (as described in the above Sections) from the coincident gross extreme weather forecast. This results in a coincident net extreme weather forecast, which is the "planning" forecast used to identify needs. Separate impacts were calculated based on typical summer and

winter contributions of the load modifying resources during the peak hours, based on technology type.

The coincident net extreme weather forecasts ("planning" forecasts) for GTA North Region are shown in Figure 7.

Figure 7| GTA North Region Net Extreme Weather Coincident Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for various collections of stations were developed to better assess the potential for non-wire alternatives to address needs. These profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section 7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Additional details on how load profiles were created can be found in Appendix C. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes through an Annual Working Group Meeting and as part of implementation of the plan.

5.8 Uncertainty in the Demand Forecast

The forecast for GTA North considers various growth drivers that each have an associated degree of uncertainty. The uncertainty in the regional planning process is managed through a flexible and adaptive approach that emphasizes monitoring, scenario analysis, and preserving future options. Development is only triggered when specific conditions are met within the designated development window, ensuring that investments are made based on clear and timely signals.

Based on the current forecast, the possibility of significantly higher winter growth rates may drive winter conditions to become more "limiting", or determine station capacity need dates, within the 2030s. This is in spite of winter ratings for transmission lines and stations being higher in winter than in the summer.

However, these winter forecasts also carry higher uncertainty due to factors like technology adoption and operational decisions, making them less reliable for immediate investment planning. Unlike summer peaks, which are largely informed by existing customer behaviour and technologies (notably widely used air conditioning), winter peaks assume continuous shifting of behaviour through adoption of electric heating and phase-out of existing gas heating. The adoption of electric heating is currently mainly driven through various level of government policies, economic incentives, and customer preferences. Due to the challenges with assuming how policy and technology will evolve over 20 years, the longer-term winter forecasts (2031-2043), have a greater level of uncertainty associated with them. They are considered in this IRRP for determining measures to preserve future options, but emphasis was placed on summer needs when determining timing of the required reinforcements.

Summer peak demand was used as a more certain foundation for guiding investment decisions, while actual winter demand trends will continue to be closely monitored to inform future adjustments. This strategy lays the groundwork for the plan to evolve cycle-to-cycle as clearer patterns emerge.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of established power system reliability standards and criteria (IESO ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards), the Technical Working Group identified electricity needs in the near-term, medium-, and long-term timeframes. Near-term needs are expected to emerge within 5 years, and/or where immediate action is required. Medium- and Long-term needs are expected to emerge more than 5 years out, and immediate actions are not generally required, unless to preserve future options.

These needs are categorized according to the following:

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during periods of peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, e.g., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the load meeting capability (LMC) of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using industry standard power system simulations.

Asset Replacement Needs are identified by the transmitter, informed by asset condition assessments, based on a range of considerations such as equipment deterioration due to age, weathering, heat stress or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement needs identified in the near-term timeframe would typically reflect condition-based information, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium- or long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

Load Security and Load Restoration Needs describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power

to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements for Ontario are described in Section 7 of the ORTAC.

Technical study results for the GTA North IRRP can be found in Appendix E. The needs identified are discussed in the following sections and are shown in the proceeding sections.

6.2 Near-Term Needs (2026-2030)

6.2.1 Station Capacity Needs

Step-down station capacity needs are determined by comparing the station peak demand forecast to the facility's LTR. In many cases, need dates can be deferred by transferring load at a station expected to reach or exceed its LTR to another nearby station that has available capacity. Feasible load transfers are already assumed in the station-level demand forecast based on input from LDC members of the Technical Working Group about the transfer capabilities and typical loading practices.

Stations will typically have a lower LTR for summer months than for winter months, as colder ambient temperatures allow more power to flow through equipment without overheating transformers and other station equipment. When a station reaches its annual peak during summer months, this becomes the only forecast scenario which requires study, as it is the most limiting condition. When stations reach their peak during winter months, however, both summer and winter forecasts should be considered as the higher winter loading may be offset with higher ratings, and either season could ultimately be the more "limiting" scenario.

When a step-down station's capacity is reached (summer or winter), and after feasible load transfers are accounted for, options for addressing the need include reducing peak demand in the supply area (i.e.., through EE or DERs) or building new step-down transformer capacity to serve incremental growth.

Typically, where there is sustained new urban growth and development in an area, measures to reduce the peak demand cannot defer or avoid the need for new station capacity indefinitely. Planning recommendations are informed by comparing the cost of these measures to the value of deferring construction of a new or expanded station.

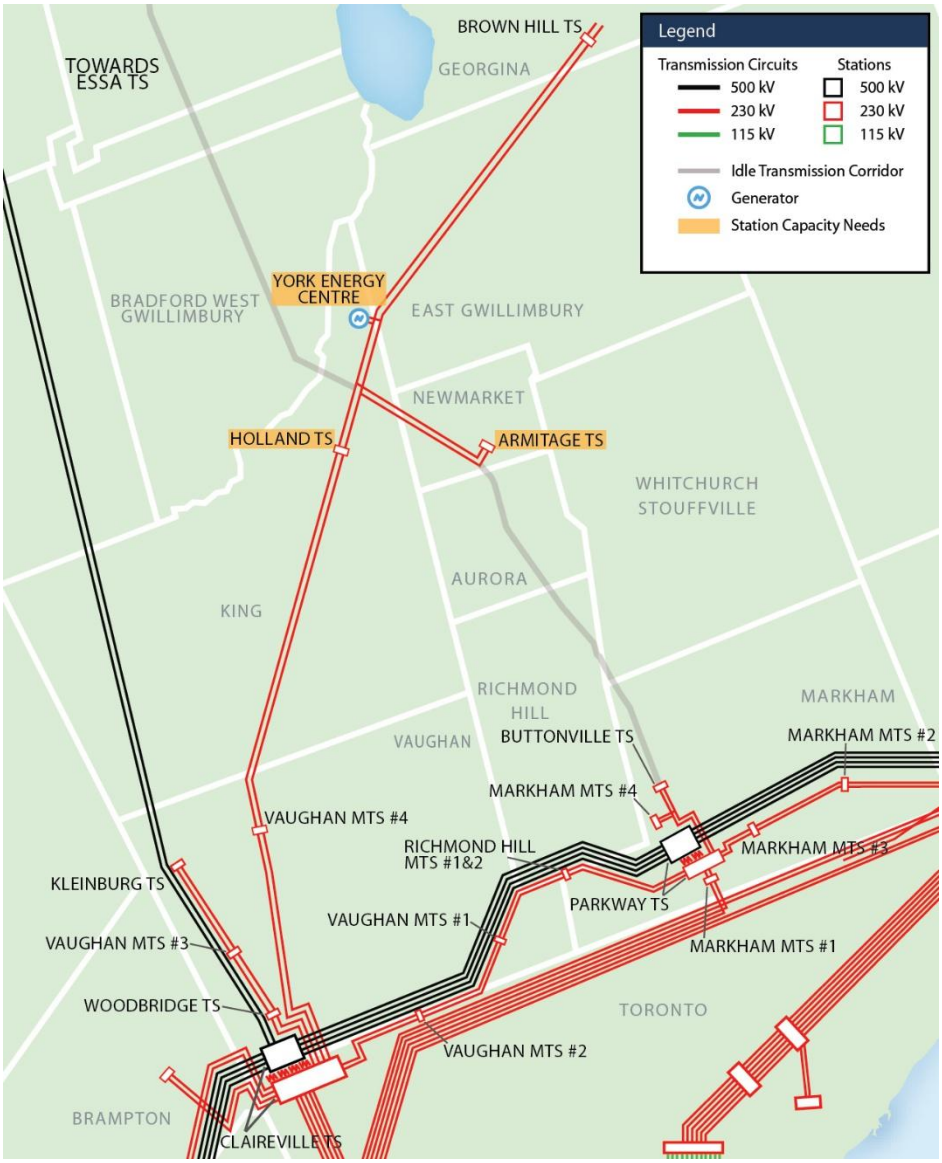
Before a new step-down station can be built, a suitable location must be identified. Stations must be connected to a part of the broader transmission system with enough incremental capacity available to reliably supply the station load. The station must also be located close enough to the anticipated customer demand to ensure that the distribution network is capable of supplying customers reliably.

Additional information on specific station capacity needs anticipated in GTA North in the near term are provided in the sections that follow.

6.2.1.1 Northern York

Northern York Region[2] electrical service territory is currently supplied by four step-down stations. Armitage TS and Holland TS are located in proximity to Newmarket and Holland Marsh, respectively, while Brown Hill TS is located further north, near Georgina, and Kleinburg TS further south, at the border between Caledon and Vaughan. Recent load growth within northern York has been served through Armitage TS and Holland TS, and forecast growth continues to be concentrated in the areas supplied by these two stations.

Figure 8| Northern York Station Needs



Although electrical service territories do not correspond directly to municipal boundaries, Armitage TS and Holland TS generally supply Newmarket, Aurora, East Gwillimbury, and parts of Bradford-West Gwillimbury, King Township, and Whitchurch-Stouffville.

[2] Term is used to refer to areas served by electrical infrastructure in the northern half of the North GTA planning area. While this roughly aligns with northern York Region, it is also inclusive of parts of neighbouring municipalities such as Bradford West Gwillimbury (county of Simcoe)

Brown Hill TS, being further north and east, supplies mainly rural areas with lower anticipated growth rates, though there is potential for longer term growth within its service territory, primarily Georgina and East Gwillimbury.

Kleinburg TS primarily serves loads in and around Bolton, as well as some rural loads throughout King township and Caledon. Supply options to meet growth in the Kleinburg TS service area, primarily concentrated in Bolton and Caledon, are currently being studied in the GTA West IRRP, though outcomes have been factored into system models used in this study.

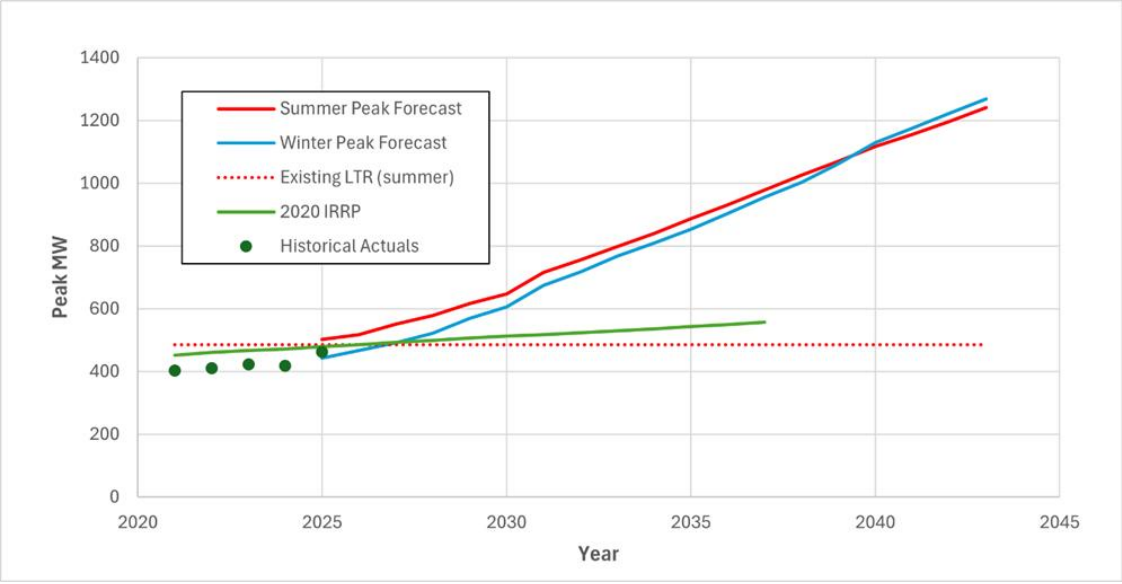
Of the four existing step-down stations, all but Brown Hill TS are currently loaded close to the maximum capability. Due to the distance between Brown Hill TS and the Armitage TS and Holland TS service territory, Brown Hill TS is not a suitable facility for transferring excess load without incurring significant distribution costs. The combined station capacity need in Northern York is summarized in Table 4. There is an immediate need to supply an additional 16 MW of demand and thus need increases to 750 MW by the end of the study forecast period.

Table 4| Northern York Station Capacity Needs

Stations	Timing	2025	2035	2043
Holland TS Armitage TS	Immediate	16 MW	400 MW	755 MW

The combined summer peak demand forecast of the approximate Armitage TS and Holland TS service territory is shown in Figure 9 along with their combined maximum rated station capacity. Also shown for comparison is the demand forecast from the 2020 York IRRP.

Figure 9| Northern York Demand Forecast

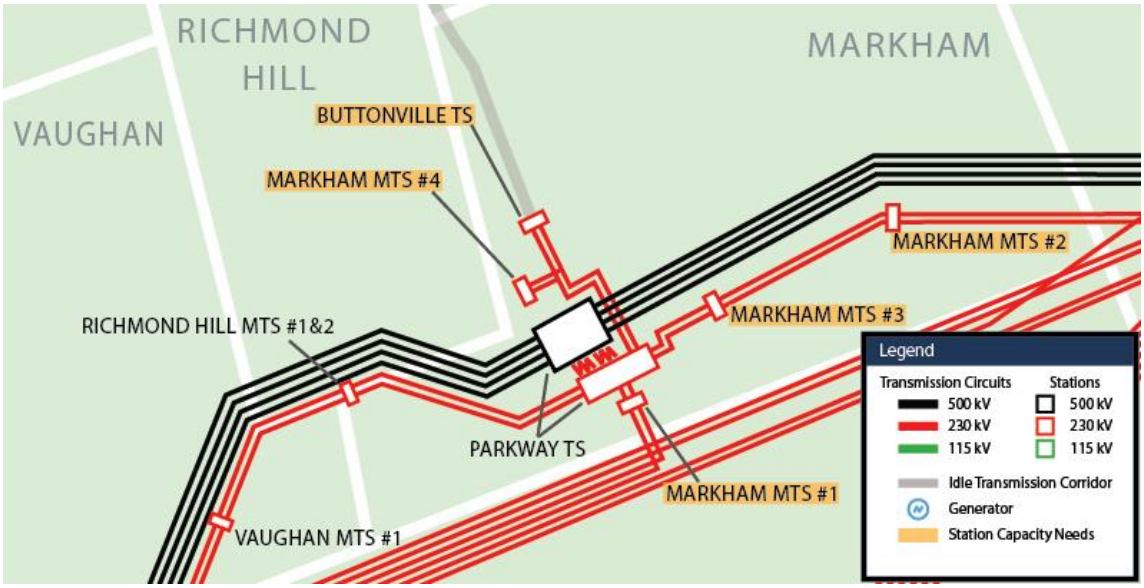


The previous IRRP had identified Northern York as having station capacity needs emerging in 2027. The development of Northern York TS #1 was recommended to address this need with a targeted in-service date of 2027, and a connection point in the vicinity of the existing Holland TS. However, based on revised demand forecasts, the need has been advanced and is now considered immediate.

6.2.1.2 Markham

Due to the ability to transfer loads between their southern stations, Alectra has typically alternated construction and loading of new stations between Markham and Vaughan to serve loads within their southern York service territory (roughly aligned with Vaughan, Richmond Hill, and Markham).

Figure 10| Markham and Area Station Needs



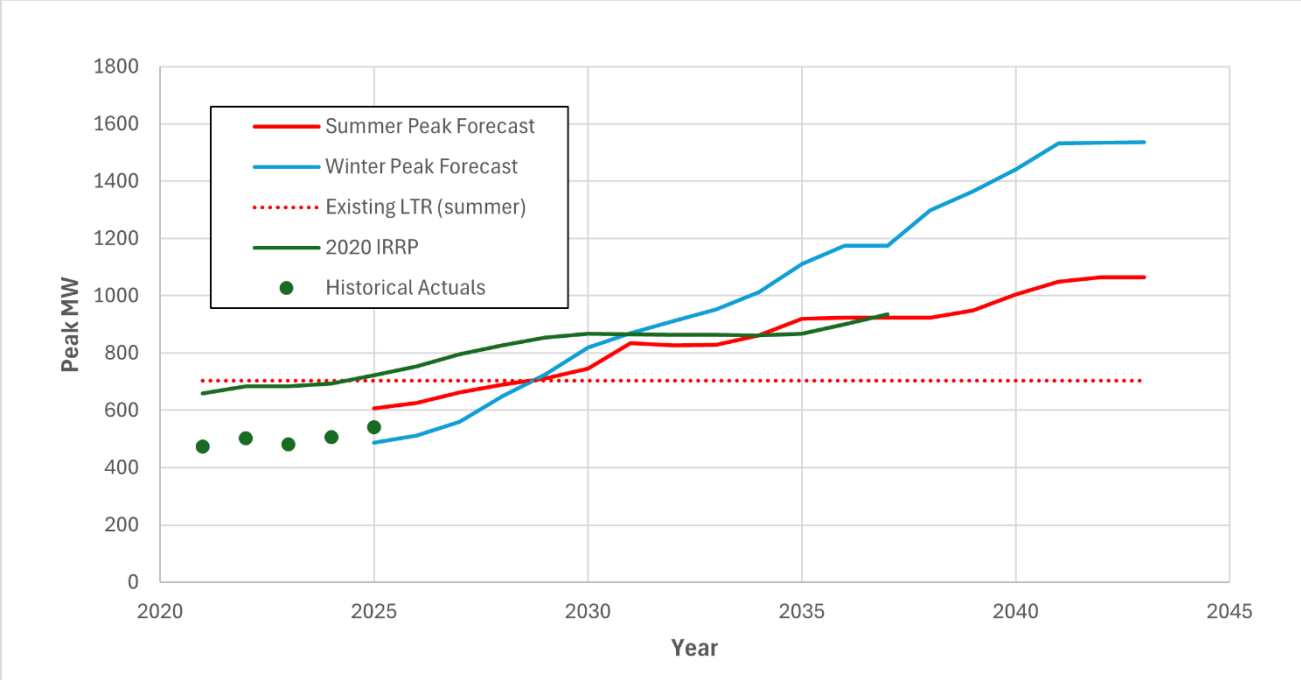
The last stations placed in service for southern York Alectra customers was Vaughan MTS #4 in 2018, preceded by Markham MTS #4 in 2011. Both of these stations had been located along the two possible transmission sections which span north from the main transmission supply path along the southern border of York region (adjacent to Highway 407). This had been done to meet the challenge of connecting increasingly northern development despite a transmission system that remains concentrated to the south.

Table 5| Markham and Area Station Capacity Needs

Stations	Timing	2025	2035	2043
Markham MTSs	Near-term	0 MW	241 MW	426 MW

The combined summer peak demand forecasts of Markham area stations (including Markham MTS #1, #2, #3, #4, and Buttonville TS) are shown in Figure 11, below, along with their combined maximum rated station capacity. Also shown for comparison is the equivalent demand forecast from the 2020 York IRRP.

Figure 11| Markham and Area Demand Forecast



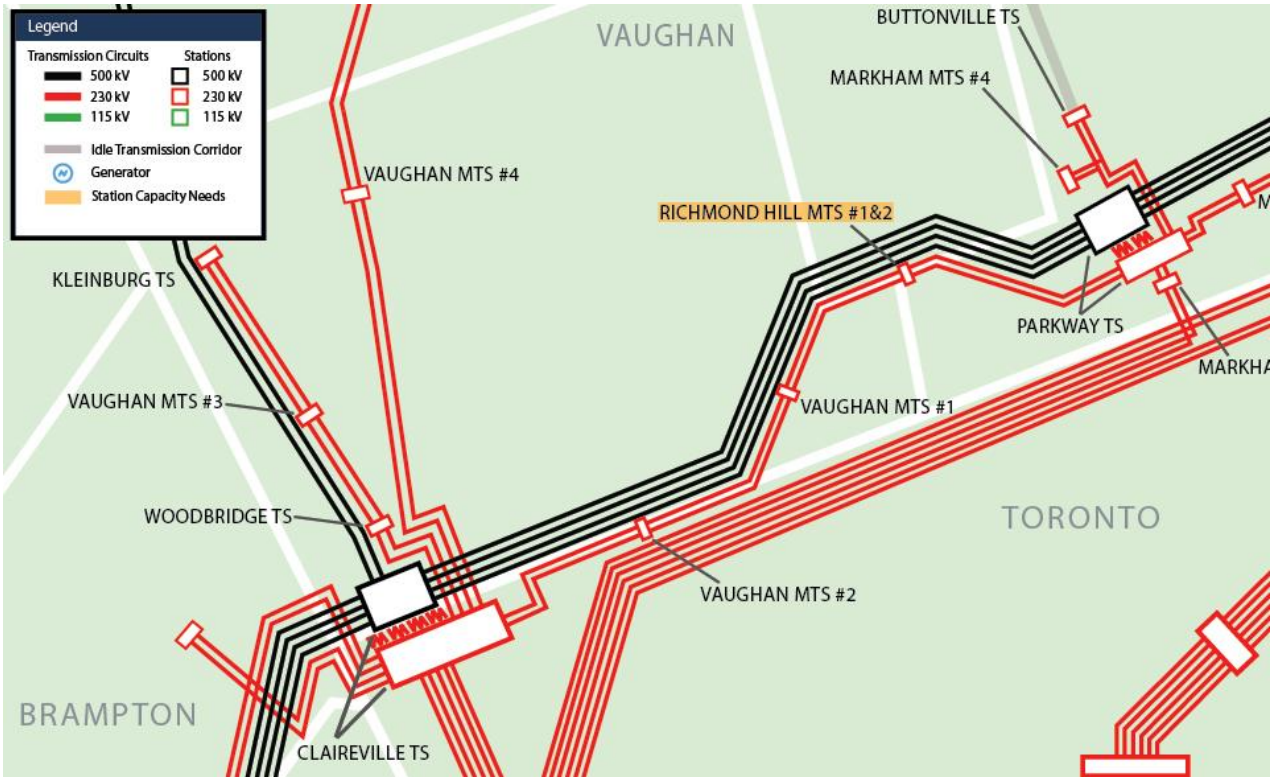
Periods of the forecast which show a relatively flat profile indicate the years in which incremental growth is expected to be met through allocation to a future Vaughan area station, resulting in no incremental growth being applied to Markham area stations. The next Vaughan area station is not expected to be required until the early 2030s (See section 7.4.1.1).

In addition to meeting total supply capacity needs of customers, addressing stations needs will also require consideration of the suitable location to site future stations, to ensure proximity to end use customers. Locating step down stations too far from customers can result in lower customer reliability and power quality, and additional distribution costs to run feeders to connect customers. Finding suitable locations to site stations to serve southern York customer loads has been increasingly challenging in recent years, as limited transmission paths exist north of the southern border.

6.2.1.3 Richmond Hill

Richmond Hill is currently the site of two step-down stations, Richmond Hill MTS #1, and Richmond Hill MTS #2. Both stations have been loaded to capacity for most of the past few summers, with new load growth in Richmond Hill supplied via load transfers to stations in Vaughan or Markham.

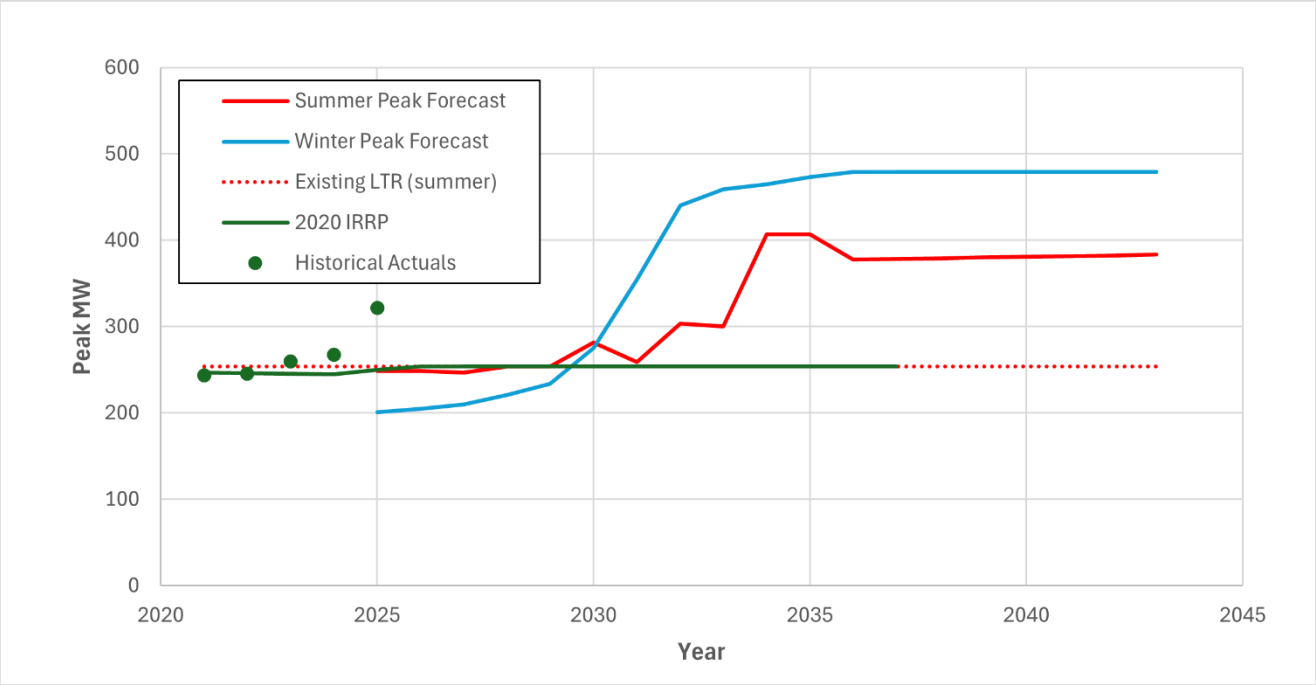
Figure 12| Richmond Hill Station Capacity Needs



Although Richmond Hill has been managing similar complexities of providing supply to increasingly northern development, a new area of intensification is emerging in the southern part of this municipality. The area, roughly corresponding to the Richmond Hill Centre (RHC) Urban Growth Centre, is the result of the planned extension of the Yonge subway into Richmond Hill and Markham. Significant, intensified development, with associated electrical demand, is anticipated in the vicinity of these new development zones.

Figure 13 shows the relatively steady loading at the existing Richmond Hill stations in recent years, and the expected impact of new growth over the coming years in the surrounding area. Growth anticipated around the new subway extension has been included in this grouped area, while growth further north (better served through northern stations in Markham and Vaughan) has not been included. Note a large jump in actual peak demand for the summer of 2025 is the result of load transfers supplied by Richmond Hill TSs during emergency conditions. The irregular loading of the summer forecast is the result of anticipated load shifting as new stations come online.

Figure 13| Richmond Hill Demand Forecast



The need for a new step-down station in Richmond Hill was not identified in the previous IRRP published in 2020. Instead, this new need is in direct response to new, intensified development in proximity to the planned Yonge subway extension. The anticipated need date for additional station capacity is 2030.

6.2.2 Supply Capacity Needs

Supply capacity needs are often described in terms of a system's Load Meeting Capability (LMC), which is the maximum amount of demand that can be supplied by a transmission circuit or group of circuits, before specific system criteria are violated. Where the demand forecast is expected to exceed the LMC, mitigation measures will be required. These can vary from lowering load to at or below the system LMC (through NWA or similar measures), upgrading the system to a higher LMC, or, depending on the type of criteria, arming load rejection (to automatically disconnect loads during a contingency to keep total demand below the LMC).

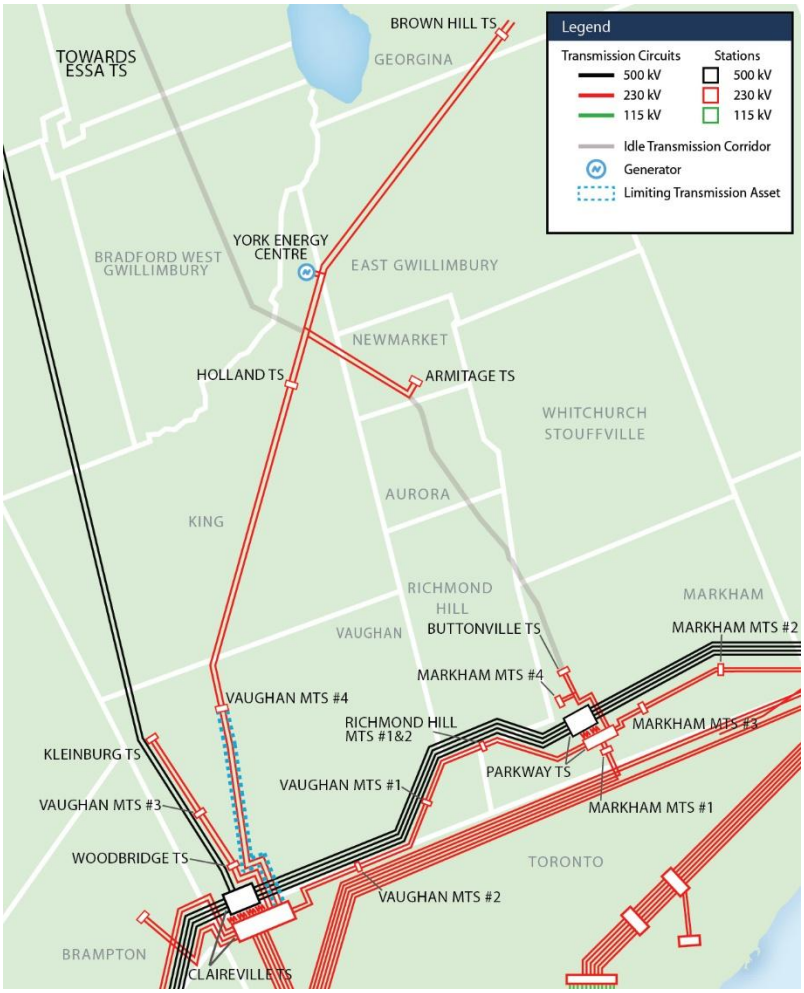
Supply capacity needs are determined based on the system performance following the simulation of standard criteria or "contingency events" during peak demand conditions. The loss of a single transmission element is referred to as an N-1 event, while simultaneous loss of 2 elements is N-2. Following N-2 events, the criteria allow for customer load loss up to a certain amount in order to keep loading on the remaining transmission facilities within acceptable limits. These "load rejection", or LR events, represent lower reliability for customers, but only in the event of a major transmission outage occurring during peak loading conditions. Although a certain amount of LR is permitted in these cases, it is not a preferred outcome, particularly when designing solutions to fully address

system needs. As a result, this study distinguishes between needs and solutions required to meet N-2 conditions both with and without LR. No load loss is permitted following N-1 contingencies.

6.2.2.1 Northern York

The Northern York electrical region is primarily supplied by one double-circuit 230 kV transmission line, which transfers power stepped down from the bulk 500 kV network at Claireville TS, and transports it northward to supply the step-down stations of Northern York. The line also directly supplies large customer connections and will supply a planned Go Transit power traction station. A second supply source connected to these 230 kV circuits is the York Energy Centre (YEC) peaker plant. This 400 MW gas-powered facility generates power when local demand exceeds the ability of the existing transmission line to reliably supply local needs and can also be dispatched to ensure provincial resource adequacy in high-demand periods. Due to its ability to rapidly respond to sudden changes in demand, YEC is useful for balancing output from intermittent energy sources, or to respond quickly following system contingencies and outages.

Figure 14| Northern York Supply Capacity Needs



There are two main double-element contingencies that result in the thermal overload on H82/83V based on the current demand forecast.

- The loss of T1B breaker at Holland TS causes the simultaneous loss of H83V and the York Energy Centre from service as YEC's stations service is supplied from Holland TS. Due to the loss of YEC's station service, approximately 400 MW of capacity is also lost. Due to these conditions, the companion circuit, H82V becomes overloaded in 2025.[3] Note that the recently commissioned Battery Energy Storage System (BESS) at YEC remains in service during this outage and improves the LMC of the system by approximately 50 MW.
- A breaker failure at L82L88 at Holland TS simultaneously removes circuits H82V and B88H from service. While this does not remove YEC from service, under normal operating conditions it will remove the G1 unit, and up to ~200 MW of generation. The BESS unit, which is connected through the G1 yard, would also be removed from service during this contingency. At peak demand, due to these conditions, the companion circuit, H82V would become overloaded in 2027.[4]

Additional Needs in Northern York – Under and Over Voltage

Undervoltage

In the event of the simultaneous loss of H82V + H83V, this sub-system becomes radially supplied from the north, via Minden TS through B88/89H. Due to the length of B88/89H, especially in high load conditions, the subsystem's voltage drops to unacceptable levels. With the loss of H82/83V, York Energy Centre is unable to provide voltage support due the station supply coming from Holland TS (which is lost by configuration following this contingency).

In addition to unacceptably low voltage levels within York region, under high load conditions this contingency would cause overloads on sections of the M6E circuits running between Essa TS and Minden TS, as this becomes one of the few remaining routes for power to flow into northern York.

The YEC BESS is not removed from service by this contingency, and while it does help provide support, it is not sufficient to address voltage needs in Northern York or overloads on M6E. Based on the current forecast, this need materializes in 2025.[5]

Overvoltage

The simultaneous loss of B88H and B89H removes Armitage TS, Brown Hill TS, and YEC from service, and leaves a lightly loaded radial circuit from Minden TS supplying the relatively smaller load centres at Beaverton TS and Lindsay TS. Due to the length of the circuits from Minden TS towards Northern York, especially in lighter load conditions, the subsystem is like to experience an unacceptable increase in voltage. This is further exacerbated by the presence of the use of capacitor banks at Beaverton TS and Lindsay TS, which help support low voltage conditions when the full system is in service and voltages are at risk of running low. This need had been identified within the last IRRP. Although actions have not yet been taken to fully address it, unacceptably high voltages haves not been observed within the area

[3] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

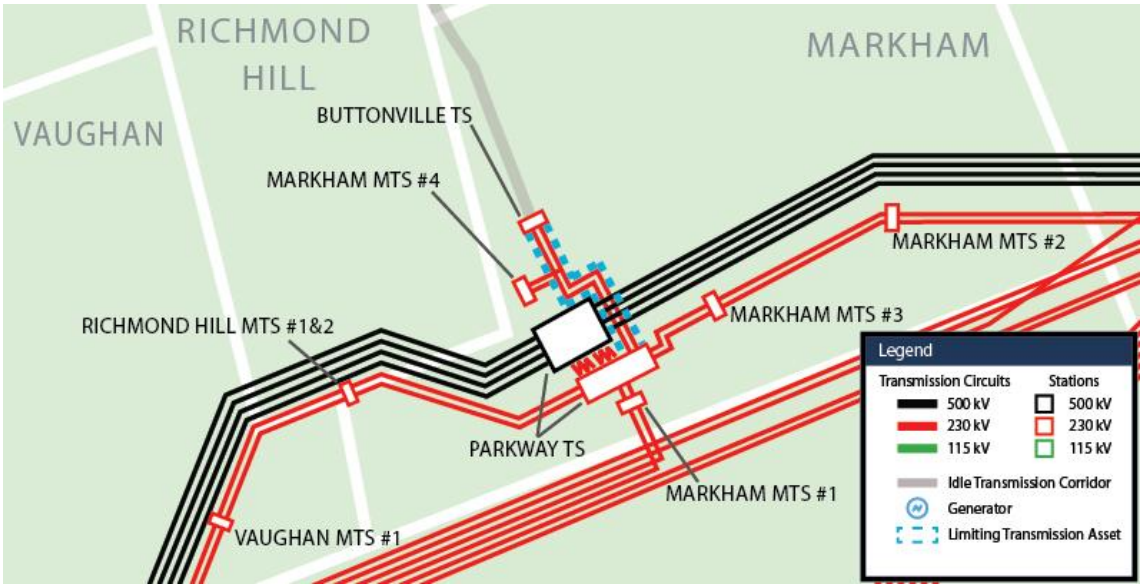
[4] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

[5] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

6.2.2.2 Markham and Area (Parkway-Buttonville)

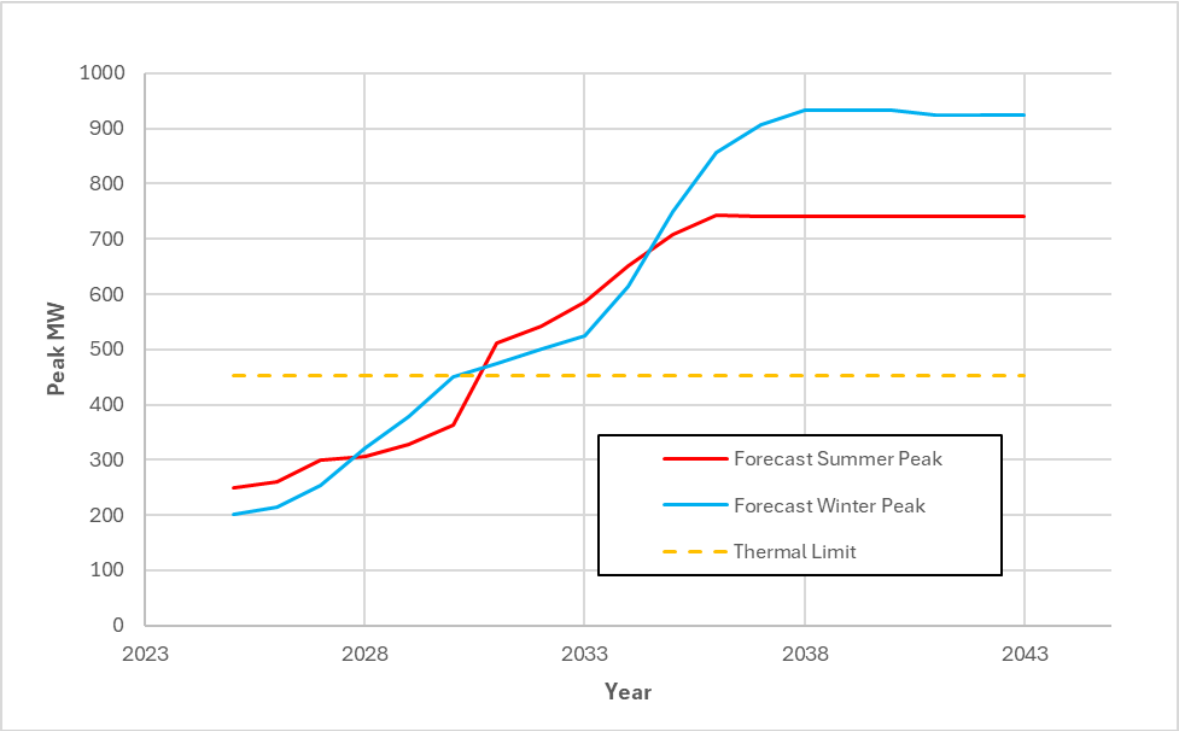
The Parkway – Buttonville radial circuit is a two circuit (P45/46), 230 kV transmission tap which currently stretches approximately 6 km north of Parkway TS into Markham region. Power stepped down from the bulk 500 kV system at Parkway TS and flows north to supply two step-down stations, Markham MTS #4 and Buttonville TS.

Figure 15| Parkway-Buttonville Supply Capacity Needs



As the only existing northern link into Markham region, this circuit is expected to be loaded with a new step-down station, Markham MTS #5, recommended in the previous IRRP. The maximum loading on this circuit is approximately 450 MW and is based on the thermal limit of the companion circuit when one of either P45 or P46 is out of service. The forecast load to be served by this circuit is shown in the graph below, along with the existing transmission thermal limit:

Figure 16| P45/46 loading forecast for southern section, and Thermal Limit



The existing transmission circuits are roughly sufficient for serving both existing stations to their summer LTR, plus an additional 133 MW from a new step-down station. Based on the planned in-service date of Markham MTS #5, and loading rate, this need is expected to be reached in 2031.

6.2.3 Load Security and Load Restoration Needs

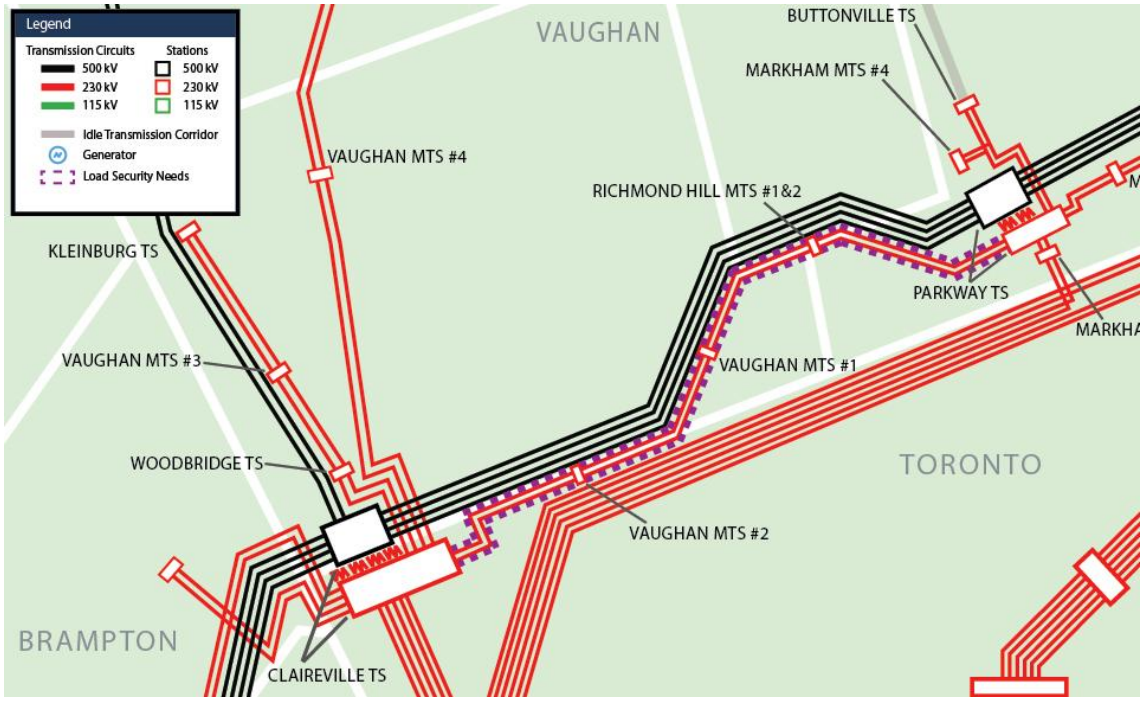
Load Security and Load Restoration needs refer to the level of reliability customers can expect when major contingencies occur. Security refers to the maximum amount of load which can be simultaneously lost following any of the defined planning contingency types as specified in ORTAC. In general, no more than 600 MW is permitted to be lost after an N-2 contingency through a combination of loss by configuration (from loss of supply to a station), or Load Rejection (automatically tripped load to keep remaining facilities within their applicable loading limits). Load Restoration refers to how quickly load can be reconnected after a major transmission outage. It can be determined by factors such as the distribution network's ability to transfer loads to other nearby stations, remoteness, and the nature of the interruption/equipment affected (e.g., overhead versus underground facilities) York Region typically performs well for restoration, given Alectra's meshed distribution network, the proximity of Hydro One crews and equipment to the GTA, and the mainly overhead transmission system. Due to good historical performance, no restoration needs have been identified in this area which require actions to be taken at this time. Security needs are outlined below.

6.2.3.1 Southern Vaughan/Richmond Hill (Parkway-Claireville) Security Needs

The Parkway to Claireville circuits are a double 230 kV transmission line which spans between Claireville TS and Parkway TS, roughly adjacent to Highway 407, along the southern border of Vaughan, Richmond Hill, and western Markham. Supply is provided from the bulk network at both ends of this corridor, as Claireville TS and Parkway TS both have autotransformer connections to supply the 230 kV system from the 500 kV system.

Five municipal step-down stations are connected to the corridor today (Vaughan MTS #1, Vaughan MTS #1E, Vaughan MTS #2, Richmond Hill MTS #1, and Richmond Hill MTS #2). When all stations are fully loaded to their LTRs, up to 713 MW can be supplied at once, with the 600 MW security limit frequently being exceeded. These load levels were exceeded during the recent 2025 summer peak, when total loads reached 734 MW due to load transfers from neighbouring stations to address a separate distribution outage.

Figure 17| Parkway to Claireville circuits (V71/75P)



This corridor has previously been flagged as being at risk of violating security limits. In previous regional plans, it was recommended that remote operated switching facilities be installed along this corridor. These have since come into service and allow approximately half the load along this corridor to be restored in a short amount of time in the event of an N-2 contingency removing the entire corridor from service. Although this does not eliminate the risk of losing over 600 MW, it was determined that this solution would substantially address customer reliability needs, at a relatively low cost, while improving operational flexibility.

However, the present-day security need is expected to worsen when the planned Richmond Hill MTS #3 comes into service, tentatively scheduled for 2030. When all stations are fully loaded up to their LTRs, up to 866 MW could potentially be at risk of interruption in the event of a N-2 contingency occurring during summer peak.

Table 6| Parkway to Claireville Load Security Needs

Infrastructure	Timing	2025	2035	2043
Parkway to Claireville 230 kV	Immediate	94 MW	293 MW	359 MW

This represents a significant increase in the potential violation of security criteria for the area. The application of security criteria has also recently been amended through a revision to ORTAC, placing greater urgency on the need to address outstanding security needs, and only consider exemptions (as had been in place) as a temporary measure. Both the increases in demand forecasts and changes to security criteria, now require this security need to be treated as urgent.

6.3 Medium- and Long-Term Needs (2031-2040)

This section outlines longer term needs (expected to arise in 5+ years timeline), where development actions are not yet required to be undertaken. However, actions may still be required to preserve options, for instance, in the identification and preservation of land to accommodate future facilities. This is particularly the case for needs anticipated within the 5 to 10 year timeframe (medium- term needs).

GTA North is expected to be a winter-peaking region by early 2030s. As discussed in Section 5.8, demand forecasts associated with winter peaks carry a level of uncertainty as they are associated with customer behaviours and the rate of adoption of electric heating. Understanding where future needs are expected to emerge will influence planning on the transmission system to ensure upgrades can be made in time to allow for reliable connection.

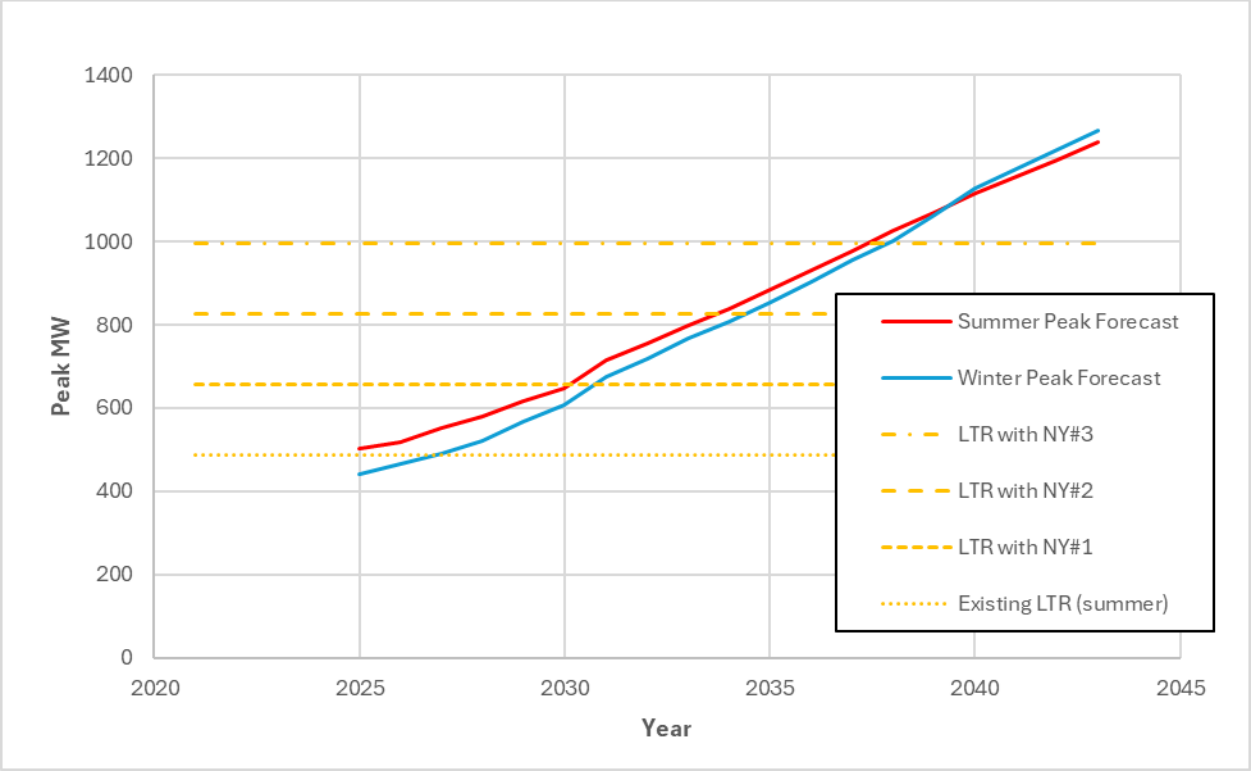
6.3.1 Station Capacity Needs

The need for step-down stations beyond the next five years is predominantly based on longer-term municipal growth forecasts and is subject to change as actual connection requests and development occurs. In particular, sudden large connection requests for major commercial customers (such as data centres) could significantly advance need dates. Longer-term step-down station needs may also need to account for winter loading conditions.

6.3.1.1 Northern York

Northern York Region is expected to continue to see significant increases in electrical demand over the next 5-15 years, driven by new development, large customer loads, and electrification of transportation and home heating. After the planned development of the future Northern York TS #1, whose need was described section 6.2.1.1, growth is expected to continue throughout the area. The graph below shows the incremental long-term challenges of meeting station capacity needs when both summer and winter needs are considered:

Figure 18| Northern York station capacity limits

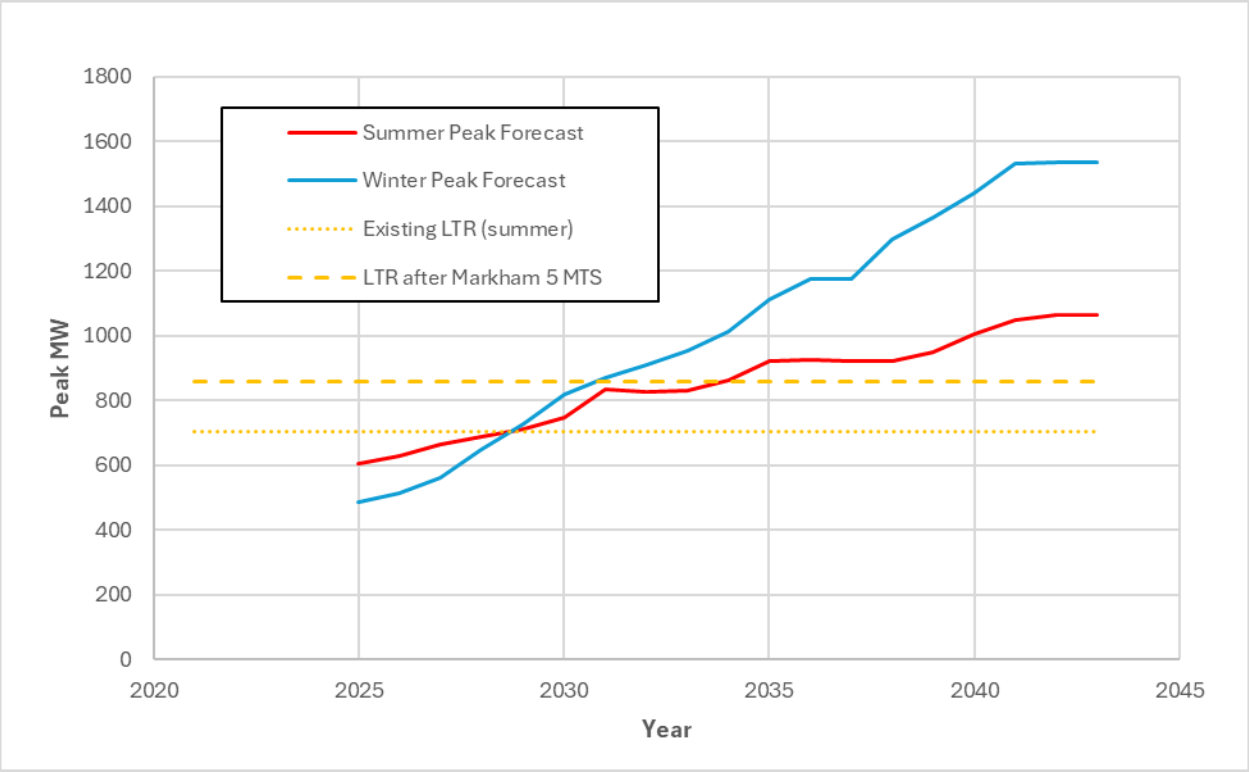


Need-dates for the second new station will depend on actual growth rates. Given the size of northern York regional, there may also be challenges associated with serving growth in the Whitchurch-Stouffville area from the future Northern York TS #1 (expected to be located over 20 km away, in King). As a result, a second new station to serve Northern York (notionally Northern York TS #2) is recommended to be located in closer proximity to eastern York load centres. In the longer term, current growth rates suggest new Northern York step-down stations may be triggered roughly every four or five years for summer-peaking conditions, or more frequently if winter-peak demand growth conditions emerge as per the forecast.

6.3.1.2 Markham

Long-term growth throughout the Alectra service territory of southern York is expected to continue at an aggressive pace in the longer term. Based on the existing summer peak forecast, and assuming the near-term need for capacity is met through Markham MTS #5, additional step-down capacity would be required in 2034.

Figure 19| Markham supplying stations, and station capacity limits



Factors such as DER uptake, pace of electrification, and residential and commercial development rates can all affect the actual need date.

As described in section 6.2.1.2, finding locations suitable for new step-down stations to meet forecast load growth in Markham has been challenging in recent years, as the existing bulk transmission system runs roughly along Highway 407 in the area, with only a 3 km extension northward. Solutions to meet near term stations capacity needs generally only consider connections to the existing transmission system as new transmission cannot be developed in less than five years. However, for longer term station needs, consideration can be given to connection points along new transmission if no feasible connection points exist from either a capacity perspective or geographic proximity. Based on concerns expressed by LDCs with serving anticipated growth centres throughout northern Markham (and northern Richmond Hill) from the existing network, siting Markham MTS #6 cannot be accomplished without new transmission in order to site the step-down capacity closer to the anticipated growth.

6.3.1.3 Vaughan

Similar to the near-term needs identified in southern Richmond Hill (described in section 6.2.1.3), there is a longer term need to provide step-down station capacity in southern Vaughan. This is directly the result of new major commercial and residential development and intensification from the Vaughan Metropolitan Centre (VMC) Urban Growth Centre. As a result, the need is not linked to remaining capacity at other nearby stations, but to the intensified demand associated with growth in this pocket. The current anticipated need date is 2033, and while this is just outside the 5-year horizon defined as near term, work is ongoing by Alectra to find suitable land and begin development to meet the targeted in-service date. The notional Vaughan MTS #5 is likely to seek connection to the existing V71/75P circuits, as these transmission facilities are near the anticipated VMC growth area. This would exacerbate existing security needs along V71/75P corridor. This would exacerbate existing security needs along V71/75P corridor.

6.3.2 Supply Capacity Needs

Supply capacity needs emerging in the longer term are generally a result of either higher loading requirements due to new step-down stations or impacts on local supply capacity resulting from potential phase out of local generators as contracts expire. System conditions can also be impacted by planned changes to the bulk system, with implications for both system needs and available solutions.

6.3.2.1 Northern York

Capacity needs for supplying incremental load growth in the near term were described in section 6.2.2.16.2.1.1, and roughly correspond to the amount of supply required to enable the connection and full loading of one additional step down station, notionally Northern York TS #1, in addition to incremental loading to bring existing stations up to their full summer LTR, and additional loads associated with electrification of Go Transit. Assuming recommendations to address these needs are put into service, additional needs will begin to emerge in the long term based on two main drivers: Continued incremental load growth associated with an additional new step-down station in Northern York and the potential retirement of York Energy Centre.

Accommodating further step-down stations in Northern York

As described in section 6.3.1.1, ongoing load growth in Northern York Region is expected to trigger the need for new step-down stations roughly every four years (summer peaking) or potentially as often as every three years (assuming high electrified heating and winter growth scenario) in the longer term.

Measures to address near term needs will be sufficient to meet the need for Northern York TS #1, while the assumed location for future Northern York TS #2 is eastward, outside of the electrical system defined as Northern York. Assuming the next station is once again sited in this area, needs should be evaluated on the assumption that additional station loading emerges in roughly the mid 2030s.

Given uncertainty with long-term growth rates, and the risk of sudden, large surges in customer demand from new development or electrification, the local system should be designed to be capable of supplying the full load of this future station, before permitting its connection. The exact nature of needs emerging from this station would depend on its connection location, as well as system changes which may be required to address the potential phase out of YEC.

At a minimum, adding this future station would trigger security needs regardless of whether it is connected on the H82/83V circuits (same protection zone as Vaughan MTS #4, Holland TS, and future Northern York TS #1), or B88/89H circuits (Armitage TS and Brown Hill TS). Seeking exemptions to security needs is not desirable in this area, given the existing operational challenges for managing this system, including maintaining adequate voltage and finding suitable windows for regular outages for maintenance.

Both scenarios, where YEC (or similar-sized generation) would remain in service, or new transmission is added to provide supply from elsewhere in the system, contribute unique challenges to the operation of this system. With the addition of potential security violations, new sectionalization should be considered a mandatory starting point to accommodate a future station. The manner of this sectionalization will ultimately influence the maximum system capability (LMC).

These options are described in more detail in section 7.4.3.4.

Considering a Potential Future without YEC

The York Energy Centre (YEC) currently serves roughly 400 MW of peak summer demand for Northern York, reducing the amount which needs to be supplied into the area from elsewhere. This facility was originally sited in Northern York specifically to offset the need for new transmission and has successfully managed the ability for the area to grow without new transmission since 2012. The contract for YEC is currently set to expire in 2035, and if it is removed from service, would represent an immediate 400 MW shortfall to local capacity to meet the area's peak demand. This 400 MW shortfall would be in addition to incremental needs from regular customer growth.

Even after the incremental upgrades recommended in section 7.3.2.2 are implemented, there would be a significant mismatch between local demand and the ability of the system to provide reliable supply. Where options to address near term needs considered measures such as reconductoring, bypassing limiting sections, and NWAs, options to meet needs of 400 MW or more are generally

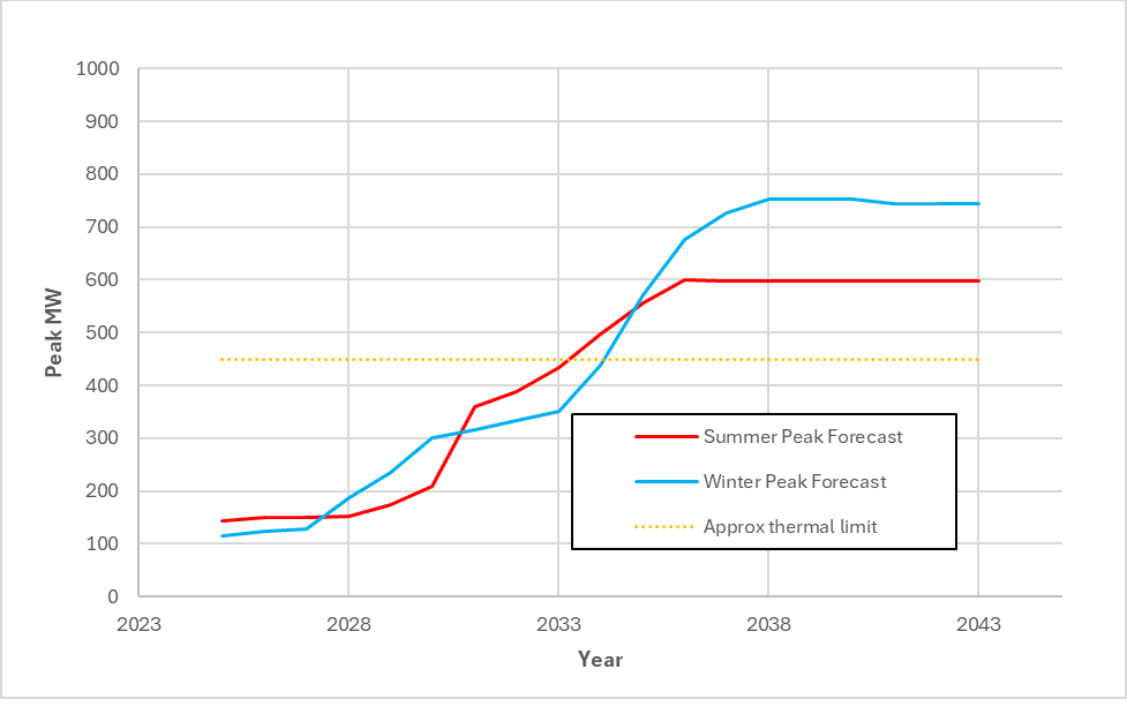
limited to new transmission lines (typically ~600 MW or more of new capacity), or local generation of a similar size and operational characteristics as what had been phased out. These options are explored in greater detail in section 7.4.3.3. If YEC were phased out without a major new supply source, it would severely affect reliability for existing customers and likely limit the ability to connect any incremental load within northern York.

6.3.2.2 Parkway-Buttonville

Capacity needs associated with the Parkway-Buttonville pocket arising in the near term were described in section 6.2.2.2, and emerge along the southern end of the P45/46 circuits, between Parkway TS and Markham MTS #4. In the longer term, demand for additional step-down stations to supply growing loads in Northern Markham, Northern Richmond Hill, and the eastern section of Northern York (including Whitchurch-Stouffville), is expected to further load this corridor. This will trigger similar thermal needs on the remaining northern section of P45/46, between Markham MTS #4 and present-day Buttonville TS. These needs are expected to be triggered when the total load of Buttonville TS, Markham MTS #5, (future) Markham MTS #6, and (future) Northern York TS #2 reach approximately 450 MW, although actual LMC could vary depending on future station, circuit and customer load characteristics. This is in addition to security needs described in section 6.3.3.1, below.

The graph below shows the impact this will have on anticipated need dates for further upgrades, under anticipated summer peak conditions, and a potential higher growth winter peak scenario.

Figure 20|Circuit loading on northern section of P45/46 circuits (Markham MTS #4 to Buttonville), and thermal limit



Note that total summer load is expected to plateau in the mid to late 2030s, as stations reach their individual LTR, and incremental growth is instead supplied by stations in neighbouring systems. This profile could change if future stations are instead located within this supply pocket.

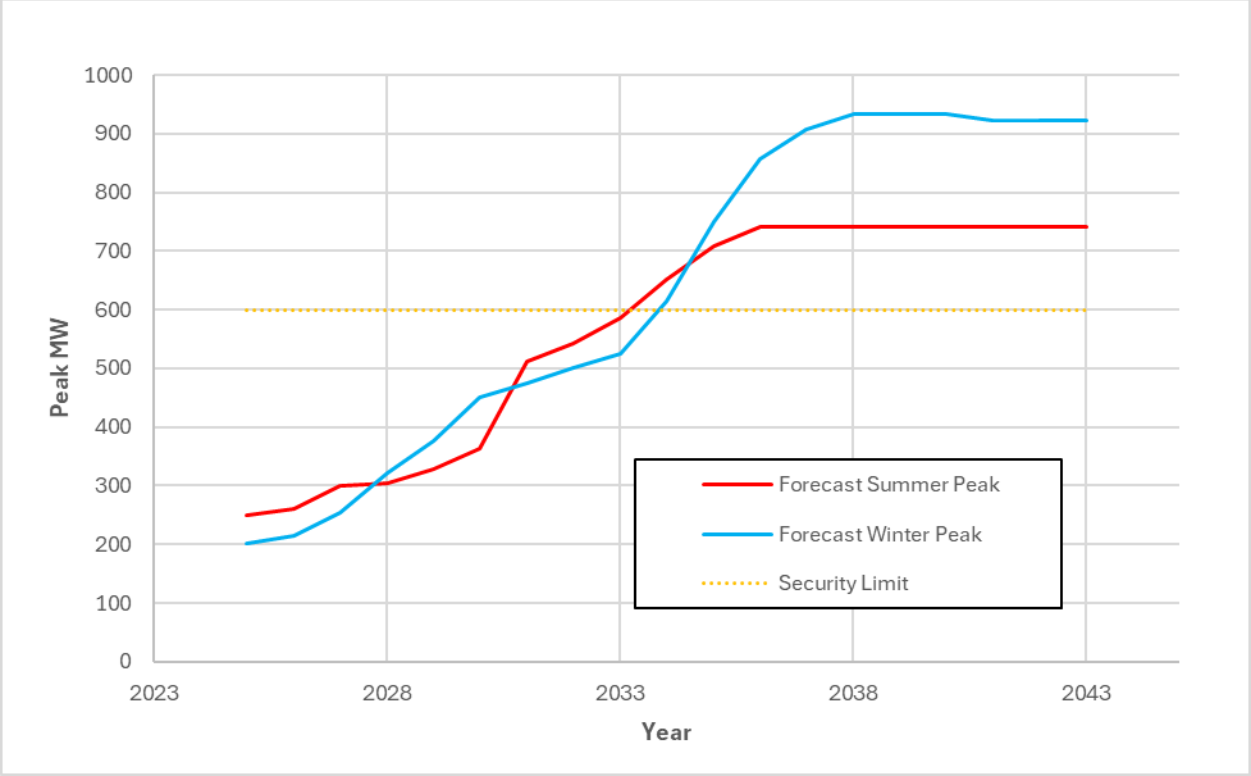
6.3.3 Load Security and Load Restoration Needs

New load security needs have the potential to emerge in the longer term as load growth increases the areas supplying over 600 MW during peak conditions. This becomes more severe when higher growth winter peak scenarios are considered. In many cases, load growth can trigger both capacity needs as well as security needs, with common solution often able to address both. The conditions under which security needs are triggered, and whether they are expected to be addressed through other initiatives, is described below.

6.3.3.1 Markham and Area (Parkway-Buttonville)

The demand forecast for this load pocket load is expected to exceed 600 MW in 2034 (both summer and winter peak forecast) which would violate applicable load security criteria. The graph in Figure 21 below shows the applicable loading, which accounts for all P45/46 connected stations (this is different from Figure 20, above, which only considered load north of Markham MTS #4):

Figure 21 | Full circuit loading on P45/46 circuits, and security limit



This assumes that the need for future step-down stations (either Markham MTS #6 or Northern York TS #2) is triggered, and transmission is available to enable their connection via a Parkway-Buttonville transmission extension. These options are described in sections 7.4.2.1, 7.4.2.2 and 7.4.2.3 and, are preconditions for triggering this security need. Note that this security need is in addition to thermal needs which are triggered in the same approximate time and are described in section 6.3.2.2. Separate solutions are required for each.

6.3.3.2 Kleinburg Radial Tap

The Kleinburg Radial tap refers to the pair of 230 kV circuits, V43 and V44, which span northwest from Claireville TS. These circuits currently supply Woodbridge TS, Vaughan MTS #3, and Kleinburg TS, with plans underway to develop a new step-down station, Vaughan MTS #6, to supply commercial loads in the area. Under normal operating conditions, part of the southern end of this corridor also partially supplies the neighbouring Goreway TS, in Brampton.

Peak demand for the Kleinburg radial pocket is expected to exceed 600 MW in summer 2029, and potentially in winter as soon as 2030. Recommendations to address supply capacity needs for Northern York are expected to address these security needs as well. Details on these proposed solutions are provided in section 7.3.2.2.

6.3.3.3 Parkway-Claireville

Based on the near-term need for an additional station to serve southern Richmond Hill (notionally Richmond Hill MTS #3), and a longer-term need for an additional step-down station to serve southern Vaughan (notionally Vaughan MTS #5), the Parkway to Claireville corridor could potentially be exposed to interruption of approximately 960 MW of peak demand. This would assume all stations are loaded to their LTR, and an N-2 contingency occurring during summer peak. In the event of winter peaks emerging in the longer term, this security risk could approach 1200 MW.

Although the security limit is exceeded today, it is unlikely that a similar exemption would be approved as additional stations seek connection. Load losses of these magnitudes, especially without comparable generation tripped from loss of the same circuits, can introduce significant challenges for balance of supply and demand at the broader bulk level. Updates to applicable security criteria in ORTAC have also introduced a requirement to pursue a permanent solution for load security needs and to only consider exemptions as a temporary measure to avoid delaying the connection of new customer loads.

Near-term recommendation outlined in section 7.3.3.1 are expected to also address this longer-term need.

6.4 Post-2040 System Considerations

Near the end of the planning horizon considered in this IRRP (2040 and beyond), identifying specific needs and developing options to address them becomes more challenging. There is, however, time to study options in subsequent planning cycles.

Understanding needs requires detailed assumptions about anticipated customer demand, seasonal peaks, and hourly profiles on a geographic basis. Given the potential for very high growth rates resulting from electrification, major new large commercial/industrial load centres, in addition to more typical growth rates associated with organic population and employment growth, predicting actual demand this far out cannot be accomplished with sufficient confidence.

The demand forecasts for summer peak, which relies more closely on existing customer behaviour and more modest electrified technology uptake, currently forecasts up to 2,100 MW of demand growth throughout York region over the next 20 years, of which roughly 1,500 MW is accounted for in this IRRP through new step-down stations and associated system upgrades to supply them. If a higher growth winter forecast is used, with more aggressive assumptions related to electrified heating in particular, up to 3,400 MW of demand growth is possible in the same time frame, with approximately 2,200 MW accounted for in this IRRP.

Supplying growth at the higher end of these projections would require greater consideration of the impact on the broader bulk electrical network. Typically, regional planning assumes the bulk system is a static source of power with sufficient ability to supply any required level of local demand. This assumption becomes challenged when considering levels of demand with the potential to affect provincial interface flows, and approach loading limits on what is typically much higher rated bulk equipment. Additionally, a future scenario where extreme demand growth is observed throughout York region would likely mean similar levels of extreme growth are emerging throughout the province, which would trigger the need for significant upgrades on the bulk system as a whole.

The combination of local demand driving bulk system needs, and assumption that bulk upgrades are required throughout the province, means that planning under this long-term high growth scenarios require close coordination between regional and bulk system plans.

Long-term bulk planning is currently underway through the development of the South and Central Bulk Plan, which considers transmission needs out to 2035, in addition to accommodating several planned changes to the provincial supply portfolio. The York IRRP has been carried out in close coordination with this plan, with implications for system assumptions and options available. These points of coordination are highlighted in the following section when options are described in greater detail.

7 Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in York Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included feasibility, cost, lead time, system benefits, and consistency potential options for addressing longer-term needs in the area.

There are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new or reinforce transmission or distribution systems. These are commonly referred to as "wire" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to manage the peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include alternatives such as local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or eDSM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wire options. Subsequently, Section 0 to Section 7.4 present the options that were ultimately developed and evaluated to the address near- and longer-term needs, respectively. Opportunities for NWAs are highlighted in their relevant options sections, with additional details provided in section 7.5.

7.1 Options Considered in IRRPs

Both wire and non-wire options are considered in regional planning, although some options may be more suitable for specific need types and characteristics. When evaluating non-wire options such as generation, local distributed energy resources, or energy storage, additional work is required to understand these specific need characteristics, including creation of hourly load profiles, as described in Section 5.7. The suitable technology types and capacities are determined by examining "unserved energy" profiles, representing the hourly demand above the existing LMC. The load profile indicates duration, frequency, magnitude, and total energy associated with each need.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. In contrast, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a generation option for local needs identified by the regional plan. Energy storage, solar generation, and wind generation were considered for generation options.

New eDSM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already

included in the load forecast, as discussed in the Section 5.4. As part of this framework and the new 2025-2036 framework, the IESO has flexibility to deliver new programs or offer regional incentive adders for existing province-wide programs to help address regional and/or local system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted. (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. At time of IRRP publication, the Ontario Energy Board is currently considering a proposal from the IESO and the Local Distribution Company community to enhance this existing mechanism to better enable IESO-LDC collaboration and co-funding of eDSM initiatives that provide both local and provincial system benefits. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wire and non-wire options, the upfront capital and operating costs are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission line infrastructure). The net present value (in 2025 CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around cost estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. Costs are typically further refined over the course of project development work. The IESO continues to participate in the Technical Working Group during the RIP and will revisit a recommendation if estimates change significantly. Furthermore, smaller scale demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

The list of assumptions made in the economic analysis is found in Appendix F.

7.2 Screening Options

As described in the previous section, an array of options is developed to meet identified needs during an IRRP, and each option is then evaluated to determine which are feasible and successfully address all needs. Final recommendations are typically made for those which are the most cost effective, although increasingly a wider range of factors are considered, including community preferences, flexibility, or providing some degree of reliability and demand forecast uncertainty risk mitigation. This process is complemented by stakeholder engagement and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 22 and further discussed in the next sections for the identified needs.

More details on the steps and inputs used in the screening mechanism can be found in Appendix C, and a summary of the options screening results for York Region is provided in Table 7**Error! Reference source not found.** for station capacity needs, and in Table 8| for supply capacity needs.

Figure 22|IRRP NWAs Screening Mechanism

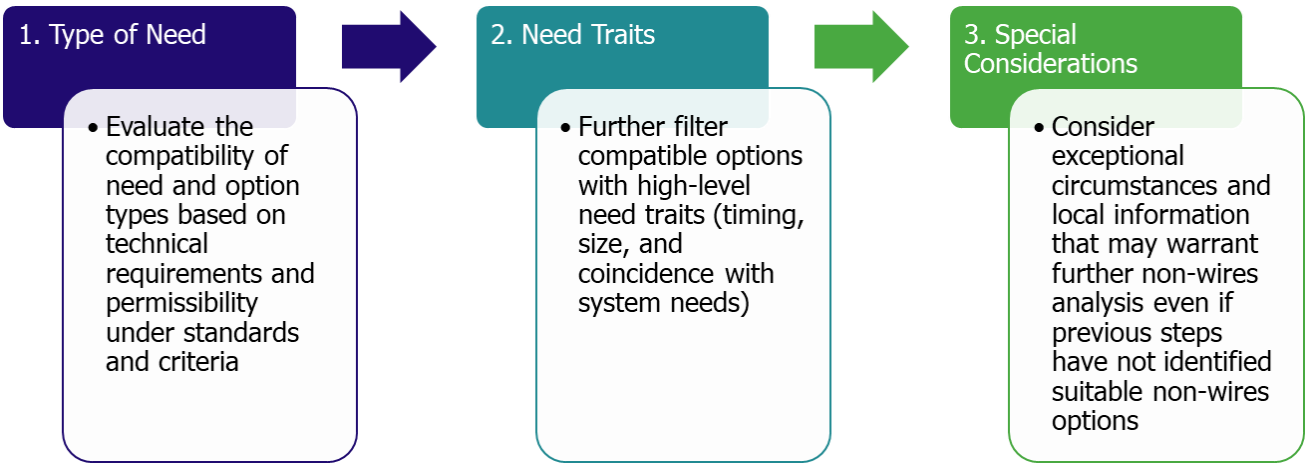


Table 7| Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity: All Subregions	• Operational measures • eDSM • Distributed generation • Wires options	• Demand response – due to magnitude and timing of need

Table 8| Options Screening Results for Supply Capacity Needs

Need	Screened In	Screened Out
Supply Capacity: Parkway TS to Buttonville TS Claireville TS to Brown Hill TS	• Operational measures • eDSM • Distributed generation • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of need

7.3 Options and Recommendations for Addressing Near-Term Needs

The following sections describe recommendations for addressing near-term needs. Unless stated otherwise, implementation is recommended to proceed immediately to ensure upgrades can be in place to address expected need dates. Where options are not expected to be in place in time, alternative measures have been highlighted to help address short term needs.

7.3.1 Options for Addressing Station Capacity Needs

The need for three step-down stations has been identified in the near term. Work should continue to identify and secure appropriate land and proceed with station development.

7.3.1.1 Northern York TS #1

The need for a new step-down station to serve growing customer demand in Northern York Region is immediate. However, the timeline for design, approval, and construction of this type of infrastructure typically spans around 4-5 years. As a result, this station is not expected to come into service any earlier than 2029.

Several approaches are recommended in the interim to manage growing customer demands before the infrastructure solution can come into service:

1. Additional electricity demand side management should be targeted in northern York region, to assist in ensuring some capacity remains available for growth of existing customer loads. Additionally, lowering peak demand through incremental eDSM would reduce the risk of Load Rejection in the event of an outage during peak load conditions, thereby improving customer reliability. Programming targeting the areas of Newmarket, Aurora, East Gwillimbury, and West Gwillimbury would be the most effective at deferring these step-down station needs.
2. Hydro One Distribution is investigating options to transfer additional loads at the boundary between the Holland TS/Armitage TS service territory and neighbouring Brown Hill TS service territory. Although large scale transfers are unlikely to be feasible given the distances between these stations, small service territory adjustments at the boundary may be effective to manage growth in the near term and still provide longer term reliability benefit due to enhanced restoration capability. Enhancing restoration capability ensures this interim measure remains cost effective by providing enduring customer benefit, even once the future station comes into service.
3. New, load connections have to seek connection through other Northern York stations with remaining capacity. It should be noted, however, that this may incur larger distribution related costs as new feeder lines may be required to cover long distances. The nearest step-down station with significant remaining or unallocated capacity is Brown Hill TS, which is located approximately 15 km northeast from the preferred location of Northern York TS #1. Until connection costs are brought down with a nearer connection point, this may delay Northern York's ability to connect new large load customers.

Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 Million[6].

For the purposes of this study, the new step-down station was modelled as connecting to the H82/83V circuits, which exacerbates the existing supply needs for this corridor, as described in section 6.2.2.1. Measures to address these needs are described and recommendations made in section 7.3.2.2. Timelines to address these needs should not interfere with the immediate development of the step-down station, as incremental needs can be met on an interim basis through the arming of load rejection through the existing Remedial Action Scheme (RAS) for Northern York Region.

7.3.1.2 Markham MTS #5

Based on existing peak demand and forecast near-term growth, the need for the next Markham area station is anticipated by 2029. Alectra has identified a suitable location for the next Markham MTS #5, and this project is currently under development. Based on recommendation from the previous IRRP, Markham MTS #5 is planned for connection near the existing Buttonville TS, supplied from the P45/46 circuits. The expected in-service date of this station is 2028-2029. Typical development costs for these types of stations, including real estate, are generally $60 Million. Supplying the full rated capacity of this station and the existing Buttonville TS and Markham MTS #4 will require supply capacity increases to the southern section of P45/46 circuits, further described in section 7.3.2.3.

7.3.1.3 Richmond Hill MTS #3

As described in section 6.2.1.3, significant development pressure in the vicinity of the Richmond Hill Centre Urban Growth Centre will require additional step-down station capacity by 2030 to reliably supply new and intensified customer demand. The area of intensification to be supplied by this new station is roughly bounded by Yonge St to the west, Steeles Ave to the south, 16th Ave to the north and Leslie St to the east. Alectra has identified a suitable location for the next step-down station to supply this forecasted growth, Richmond Hill MTS #3, which is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. The expected in-service date of this station is 2030. Typical development costs for these types of stations, including real estate, are generally $60 Million.

Once connected, loading up this new station will exacerbate existing security needs along the corridor. Although an exemption to security criteria is in place today, continued load growth on this corridor, as anticipated through the connection of Richmond Hill MTS #3 in the near term and Vaughan MTS #5 in the longer term, will require a wires solution to be put in place to address security needs. This is further described in section 7.3.3.1.

[6] Actual costs can vary depending on factors such as land costs and equipment ratings

7.3.2 Options for Addressing Supply Capacity Needs

In some cases, measures to address capacity needs will also have the benefit of addressing security needs. Where a proposed solution addresses both sets of needs, it is discussed in the sections below.

7.3.2.1 York Energy Centre Station Service

When operating, the York Energy Centre (YEC) injects power through its transmission connection point along the B88/89H circuits. However, the station service (power used to run station equipment), is normally supplied through a distribution connection from Holland TS, which is connected to the H82/83V circuits to the south of YEC. These two sets of circuits, B88/89H and H82/83V, are connected through a set of breakers that were installed in 2017, several years after YEC came into service. This created a condition where the loss of H82/83V will remove Holland TS, and subsequently YEC, from service without interrupting supply to B88/89H. This creates potential capacity and voltage related needs for the local system (described in section 6.2.2.1), which would not be as severe if YEC remained in service.

Changing the station supply arrangement for YEC would allow for YEC to remain operational under the loss of H82/83V, and the loss of the T1B breaker at Holland TS (current worst-case N-2 contingency). The impact of resolving the YEC station service issue would result in an increase of approximately 90MW in the LMC from the worst-case contingency.

There are different potential ways in which YEC station service could be addressed including:

- Installing second step-down transformer via the B89H tap point, allowing for station service to be drawn under regular operating conditions from B89H as well as the existing supply available from B88H, or;
- Installing a potential automatic station service transfer arrangement to allow for automatic transfer between the Holland TS distribution service and B88H supply points during a contingency.

The ultimate preferred service arrangement should be determined based on deeper engineering study of the cost and technical feasibility of different possible arrangements. It is recommended that the station owner work with the connecting transmitter, Hydro One, to identify and implement this system upgrade. The final configuration should allow for uninterrupted operation of YEC under all applicable N-1 and N-2 transmission planning contingencies affecting H82/83V, as well as all N-1 contingencies affecting either B88H or B89H.

Although cost estimates for this upgrade are not yet available, alternatives to provide to similar level of reliability would be orders of magnitude more costly and disruptive than the proposed station service work, and either require new transmission to create redundant supply paths into the area, or the construction of a similar sized generation facility (~400 MW) to provide redundant supply. By contrast, all anticipated upgrade options could be accommodated entirely within the existing station boundary.

In addition to improving reliability for the local area, this will allow YEC to remain operational under a wider range of system conditions, which in turn improves power and ancillary service availability for the province as a whole.

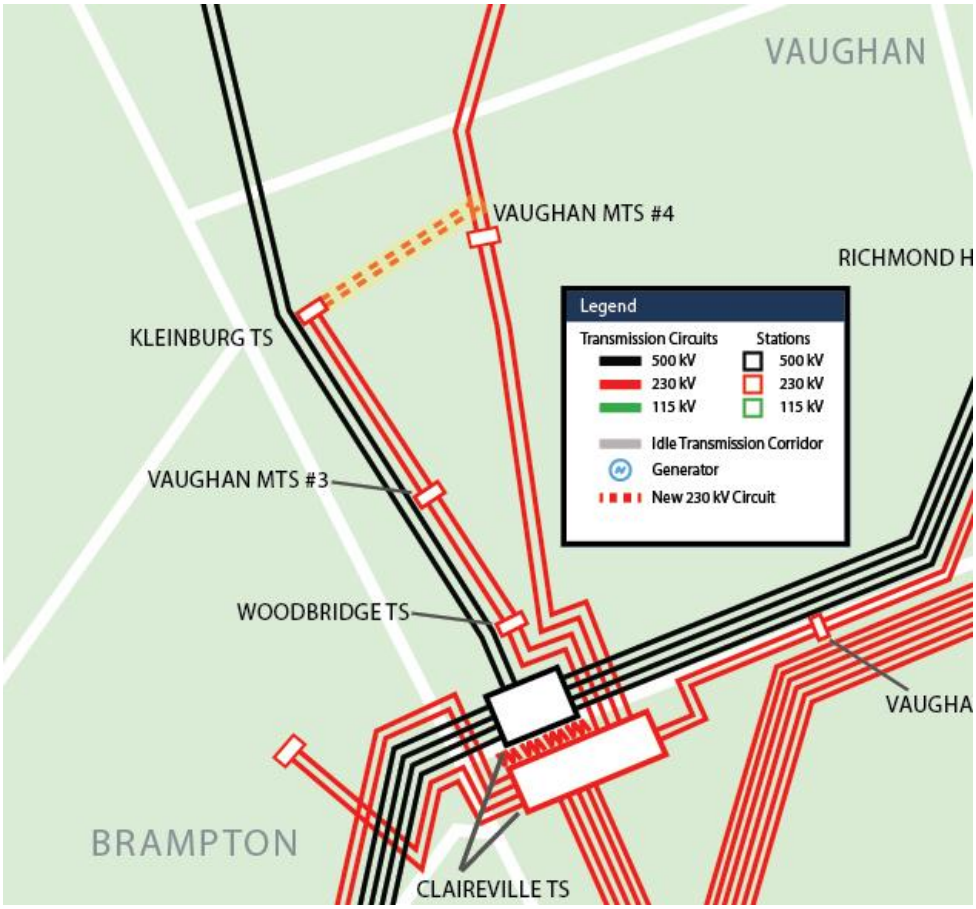
Consideration of new regulatory or contractual mechanisms may be required to finance this type of system upgrade. There is no existing mechanism for costs incurred by the station owner to be reimbursed, and it also does not fit within the existing competitive procurement streams.

Addressing this station service issue will have an immediate benefit to local customer reliability by lowering exposure to Load Rejection (LR) events, and allowing the local system to accommodate some of the additional load growth associated with the connection and loading of Northern York TS #1. Additional technical details of this analysis are included in Appendix E.

7.3.2.2 Kleinburg-Kirby Transmission Link

After addressing the York Energy Centre (YEC) station service issue (see section, 7.3.2.1), the next most limiting contingency affecting Northern York is triggered by thermal violations of the southernmost section of circuits H82/83V, which span from Claireville TS to Vaughan MTS #4. Due to a narrow transmission corridor, and close proximity to development along this route, this section is not a good candidate for reconductoring to increase capacity of the line. Instead, a new transmission route is proposed to bypass this limiting section and improve supply capacity into Northern York. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4. The notional location of the facilities is shown in Figure 23.

Figure 23| Potential Kleinburg – Kirby location



Creating this bypass would reduce the amount of power that would have to flow north from Claireville TS to Vaughan MTS #4 to reach stations further to the north. The impact on LMC depends on where new stations are ultimately located in Northern York, and the balance of demand between them, however this upgrade is expected to allow for the connection and full loading of Northern York TS #1.

The long-term need for this corridor to supply Northern York, as well as northern Peel and Halton regions, had previously been identified through the regional planning process. Additionally, the Ministry of Transportation (MTO), dealing with similar growth and intensification needs from a transportation perspective, has been working to develop the proposed Highway 413 in the same general area. More information on MTO's process is available on the project website, linked here. In accordance with the Provincial Policy Statement, which recognizes the value of co-locating linear infrastructure from a land use perspective, the IESO and Ministry of Energy and Mines have been working for over a decade to identify and preserve land in the same general vicinity as the proposed highway. This new transmission corridor would roughly parallel Highway 413, with minor deviations where required to connect with specific transmission supply points or avoid areas unsuitable for transmission. The final route, when fully built, would provide a transmission route connecting a future Milton TS to Kleinburg TS. This line would connect with the extension further east to the H82/83V

circuits in Vaughan, at a point north of Vaughan MTS #4, close to the intersection of Kipling and Kirby Rd. This proposed transmission line is referred to as the Kleinburg to Kirby link.

As an initial configuration, a double-circuit 230 kV is envisioned along this route. In the longer term, a second double-circuit line could potentially be required to further reinforce and create a separate redundant supply path to serve the southern sections of H82/83V, if additional step-down stations are required in the vicinity of the existing Vaughan MTS #4. The initial 6 km double-circuit 230 kV Kleinburg to Kirby link is estimated to cost $40 million and would likely take 6-7 years from project initiation until in service date (timelines aligned with Bulk Kleinburg TS build out, described in section 8.1). This assumes a steel lattice tower design and does not account for any additional land costs.

7.3.2.3 Reconductoring P45/46

As described in section 6.3.2.2, thermal limits of the existing P45/46 circuits are expected to be exceeded following the loss of the companion circuit when total loading on the stations supplied by these circuits (Markham MTS #4, Buttonville TS, and the future Markham MTS #5) exceeds approximately 450 MW.

Based on a review by Hydro One, it is technically feasible to upgrade the limiting conductors along this transmission corridor. Reconductoring the section between Parkway TS and Markham MTS #4 would allow the P45/46 corridor to support the full LTR at Markham MTS #4, Buttonville TS, and the future Markham MTS #5. The estimated cost would be $4.3 million.

Based on current forecasts, the need date for this upgrade is approximately 2031. However, there is value in advancing this work to coincide with the planned in-service date of Markham MTS #5 (2028-2029) for two reasons. First, once connected, there may be value in utilizing new step-down station assets at a quicker rate, such as when transferring loads during an outage on a neighbouring station, or to make more efficient use of distribution assets closer to actual customer loads. For that reason, it may not be efficient to curtail load at this station once it is connected. The second reason deals with operational and logistic challenges of managing reconductoring work. Typically, one of the conductors being upgraded would need to be taken out of service for long periods of time, limiting supply capacity of the system for weeks, or even months at a time. This timing of work will need to be carefully planned to coincide with periods of time when demand is expected to be lower. However, the longer the work is delayed, the more challenging it can be to carry out, as available windows for taking these types of long outages become shorter.

Hydro One, with the IESO, should determine a preferred window for carrying out this work as part of the RIP process.

7.3.3 Options for Addressing Load Security Needs

The sections below describe preferred solutions to address load security needs. In the past, LDCs and transmitters have had the option of jointly applying for exemptions to security criteria, where the cost of upgrades is expected to exceed customer benefit. Although the IESO has typically granted these exemptions, revisions to applicable criteria now only permit exemptions as a temporary, or stop gap measure, where longer term solutions may take additional time to implement.

7.3.3.1 V71/75P Circuit Breakers

As described in sections 6.2.1.3 and 6.3.1.3, security limits are exceeded along the V71/75P circuits today, and this is expected to worsen once Richmond Hill MTS #3 connects, and in the longer term Vaughan MTS #5. Although an exemption to security criteria is in place today, it is not anticipated that it will continue to apply as revisions to security criteria now require longer term plans to address needs to be in place. Additionally, the scale of the security need has surpassed 730 MW during the most recent 2025 summer peak, and rapid anticipated load growth from new stations on the corridor is (linked to existing urban development plans). As a result, there is an immediate need to address load security for stations supplied by these circuits.

Existing switching facilities along this corridor allow for the partial restoration of load following the loss of two transmission elements, but they do not prevent the full load along the corridor from being lost immediately following a double contingency affecting both circuits. By adding inline breakers near the midpoint of the V71/75P circuits, a contingency affecting both circuits would only cause the loss of roughly half of the connected stations, significantly reducing the amount of load interrupted. The exact amount of load lost would depend both on the placement of the breakers, and the future connection points of Richmond Hill MTS #3 and Vaughan MTS #5. A suitable location for these breakers would be one where the simultaneous loss of the V71/75P circuits at a single point along the corridor (i.e., a credible common tower contingency) would not interrupt more than 600 MW of load.

Given the proposed connection point for Richmond Hill MTS #3, one notional option would be to locate these breakers along the 6 km stretch between present day Vaughan MTS #1, and Richmond Hill MTS #1. When Richmond Hill MTS #3 is connected, and all six stations on the corridor are fully loaded to their summer LTRs, this would expose a maximum of 459 MW to interruption for a common tower double-circuit contingency. Assuming the future Vaughan MTS #5 is connected east of these breakers, along the same section as the Richmond Hill MTSs #1, #2, and #3, the longer-term maximum interruptible load would be 560 MW, still within acceptable security limits. An ideal location for these breakers would therefore be between present day Vaughan MTS #1 and the future Vaughan MTS #5.

Identifying the exact location for the future breakers will require detailed review of the existing transmission corridor, both to find an area where they can be accommodated without requiring additional land acquisition and ensure development work can be undertaken without disrupting operation of any existing facilities. The Working Group recommends that Hydro One identify a preferred location for connecting in line breakers along V71/75P within the scope of the upcoming York RIP and then proceed to implement this project. Typical costs for this type of infrastructure range from $30 million to 35 million and take approximately three to four years to develop. As the V71/75P circuits are owned and operated by Hydro One, it is not a suitable candidate for competitive procurement.

7.4 Options for Longer-Term Needs

Longer term options to address needs throughout York Region will be informed by actual demand growth, location of future step-down stations, and longer-term local generation supply availability. The following sections describe potential outcomes based on best available estimates of how these factors will evolve. Unless stated specifically, actions are generally not required at this time, unless it is to preserve longer term options.

7.4.1 Options to Address Southern Vaughan, Richmond Hill, and Markham Needs

The area served by stations connected to the V71/75P circuits roughly aligns with Southern Vaughan, Richmond Hill, and Markham. Security needs exist today, though are managed through exemptions to applicable criteria. Longer-term needs and options are linked to ongoing customer growth, intensification, and managing security needs as they worsen when new step-down stations connect.

7.4.1.1 Vaughan MTS #5

The longer-term need for a new step-down station to supply southern Vaughan is described in section 6.3.1.3. The preferred location for future connection would be in the vicinity of Vaughan Metropolitan Centre (VMC), which is easily accessible from connection points along the V71/75P circuits. Although security limits are already exceeded along this corridor today, the ideal location of these circuits make any other connection point for a station intended to supply VMC impractical. Instead, Vaughan MTS #5 is recommended for connection along V71/75P, and measures to address outstanding and worsening security needs will be explored separately. Near-term recommendations for addressing security needs have considered the anticipated longer-term impact of connecting this step-down station. Details on recommendations to address security needs are provided in section 7.3.3.1.

The need date for Vaughan MTS #5 is linked to growth within the VMC pocket, and not to overall capacity at remaining southern York stations. Alectra has indicated that they are working towards a 2033 in service date, based on connection applications and approved municipal plans. Actual need date may vary depending on develop timelines for new customers in the area. Although the need date is outside of the five-year near-term window, work should continue towards this targeted completion date. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2 Options to Address Northern Markham, Richmond Hill, and Whitchurch-Stouffville Needs

The areas of northern Markham and Richmond Hill, in addition to eastern sections of Northern York, currently have limiting step down station capacity due to their long distances from the existing transmission network. As urban boundaries continue to expand northward, and rural loads intensify, this will trigger the need for new transmission stations, and transmission infrastructure to supply them. Individual options and their timing are described below.

7.4.2.1 Northern York TS #2

As described in section 6.3.1.1, the preferred location for the future Northern York TS #2 would be in closer proximity to growing load centres in the eastern half of Northern York. Whitchurch-Stouffville has been identified as a particularly challenging area for meeting long term distribution connection requests as it is expected to see significant load growth over the coming 20 years, and is also far removed from existing transmission infrastructure. Supplying customer loads, especially denser demand from high electricity use customers or more urban/suburban development, becomes more challenging for distribution networks the further they are from the transmission supply point. This can result in more expensive connections, and poor customer reliability.

Additionally, the most recent step-down stations built to supply Northern York (Holland TS and Northern York TS #1) have been or will be built in the same general area in western Northern York, with connection to the same supplying circuits. Diversifying the location of step-down stations provides benefit to customer reliability by allowing alternate supply paths through the distribution network to manage planned or emergency outage conditions.

An ideal location for Northern York TS #2 would therefore be close to the eastern sections of Northern York. No transmission infrastructure currently exists in this area, which means triggering development of this step-down station will also require development of new transmission to supply the station. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2.2 Markham MTS #6

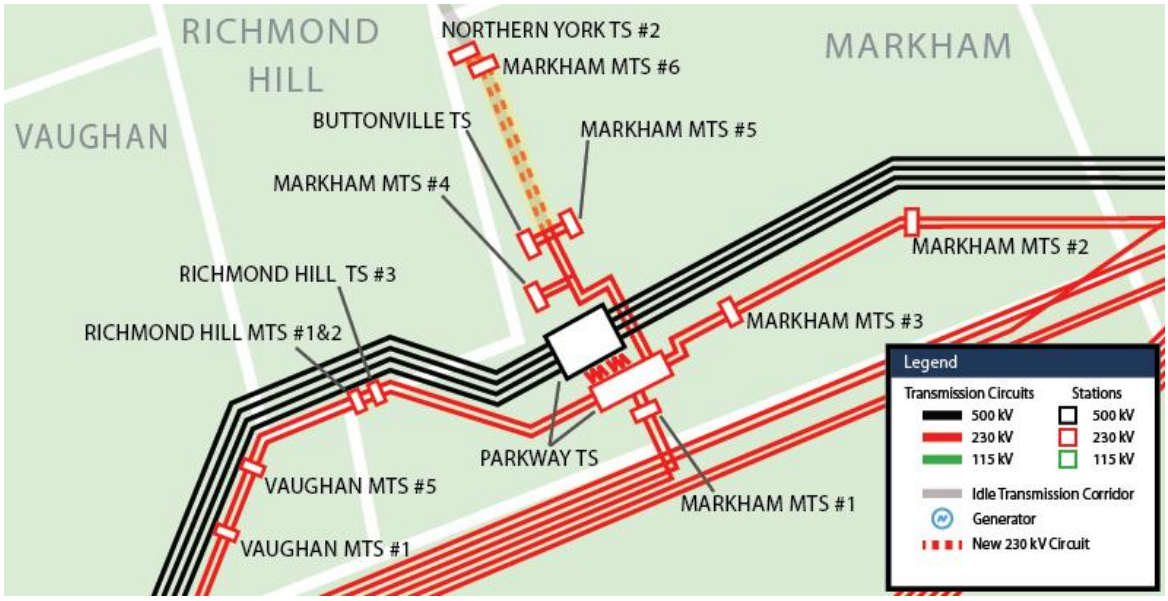
As described in section 6.3.1.2 continued urban expansion throughout northern Markham and Richmond Hill is expected to trigger the need for a new step-down station in around 2034. Actual need date could vary depending on actual demand growth in the area, which is influenced both by new as well as intensified customer demand, but also by the successful uptake of NWA where it can offset peak demand growth. Because the driver for this station is growth in the northern section of these municipalities, and because transmission does not currently extend beyond ~3km from the south of Markham, this station could not be built in a way that allows for efficient or reliable service to customers today. As a result, pursuing the development of this future step-down station will also require a parallel development of new transmission to allow connection closer to anticipated load centres. An existing, idle transmission corridor already exists in a suitable area and could be leveraged to enable this connection. This is explored in section 7.4.2.3, below. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2.3 P45/46 Transmission Extension

As described above, connecting and supplying the future Northern York TS #2 and Markham MTS #6 in the longer term will require extending the existing transmission system a further 7 km (approximately) into northern Markham. An idle transmission corridor already exists and can be repurposed for new infrastructure without requiring new land acquisitions. The existing towers and

conductors, rated for 115 kV, would need to be rebuilt to a 230 kV standard. The location of the idle transmission corridor and the general location of future step-down stations are shown in Figure 24.

Figure 24| P45/46 transmission circuit extension into northern Markham



Alternative connection points for the future Northern York TS #2 and Markham MTS #6 stations would require either developing new transmission rights-of-way to supply the emerging load in northern Markham or locating the new station capacity along the existing transmission, which would be far from the anticipated growth. Neither of these alternatives are preferred to repurposing the idle transmission corridor. New transmission corridors through heavily built-up areas would be significantly more costly and disruptive to the community. Alternatively, locating new step-down stations farther away from the load would require long distance distribution lines and would introduce reliability risks and potential voltage support challenges due to the load density and distance from the transmission supply.

Based on comments received through engagement, there is a strong local preference for deferring the need for new transmission infrastructure in Markham for as long as possible, and for considering less visually intrusive technology types when the transmission is ultimately required.

The need for new transmission is directly linked to the need for new step-down transmission stations to serve Markham, northern Richmond Hill, and the eastern half of Northern York region. Measures that target peak demand reductions in these areas could have deferral benefits pushing the need for these stations and consequential transmission expansion. As a result, it is recommended that NWAs be targeted in this area, with particular focus on Markham, parts of northern Richmond Hill (i.e., in areas not associated with intensification along Highway 407 and Yonge subway extension), Aurora, and Whitchurch-Stouffville. These initiatives could produce net positive economic benefits by deferring infrastructure needs. The combined station development costs, including real estate, are estimated at approximately $120 million, while the minimum transmission cost is estimated at $45.5 million, and costs could be higher depending on the transmission technology type (e.g., monopole towers or undergrounding).

Should the transmission expansion be required to supply growth in northern Markham, there are technology types that can be considered at the time of designing the facilities to reduce the potential visual impact. For example, steel monopole tower designs, although more expensive than lattice tower structures, can be used in urban areas to minimize foundations and leaves more space for secondary uses. These alternative tower types may also be preferred by neighbouring communities due to their less industrial aesthetic. Underground transmission may also be preferred by communities, but undergrounding is generally reserved for cases where overhead facilities are not technically feasible due to their very high costs. Underground transmission cables can be several times more expensive than overhead lines, with the incremental cost related to undergrounding likely borne by the benefitting community. Other trade-offs associated with underground cables are a lower asset life expectancy, and longer and costlier repair and maintenance. Cables are less likely to experience outages due to factors such as weather, animal contact, and vehicular accidents, but may be more prone to impact from overland flooding or drought conditions. Given that this transmission corridor would be supplying radial loads (i.e., no redundant supply from both ends), interruption to customer loads could be significant if a contingency impacted an underground cable. A comparison of overhead and underground technologies for this transmission is provided in Table 9.

Table 9| Estimated cost of ~7km transmission extension along existing Right of Way in Markham

	Life of Asset (Years)	Cost ($M)
Lattice Tower	90-100	45.5
Cable	40-50	175

Decisions for the final technology type of new transmission lines are not typically made until the Environmental Assessment (EA) stage of line design.

7.4.2.4 P45/46 reconductoring to Buttonville

The near-term recommendation to reconductor the limiting section of P45/46 circuits (described in section 7.3.2.3) only considered the need to reconductor the section between Parkway TS and Markham MTS #4. This upgrade would allow for the full loading up to station LTR of Markham MTS #4, Buttonville TS, and future Markham MTS #5. In the longer-term, step-down station needs are expected to trigger the extension of circuits P45/46 and connection of two additional step-down stations: Northern York TS #2 and Markham MTS #6. The collective load of these five step-down stations would exceed both security limits and supply meeting (thermal) capacity of the remaining P45/46 circuits section between present day Markham MTS #4 and Buttonville TS. Options to address security needs are described in section 7.4.2.5, below.

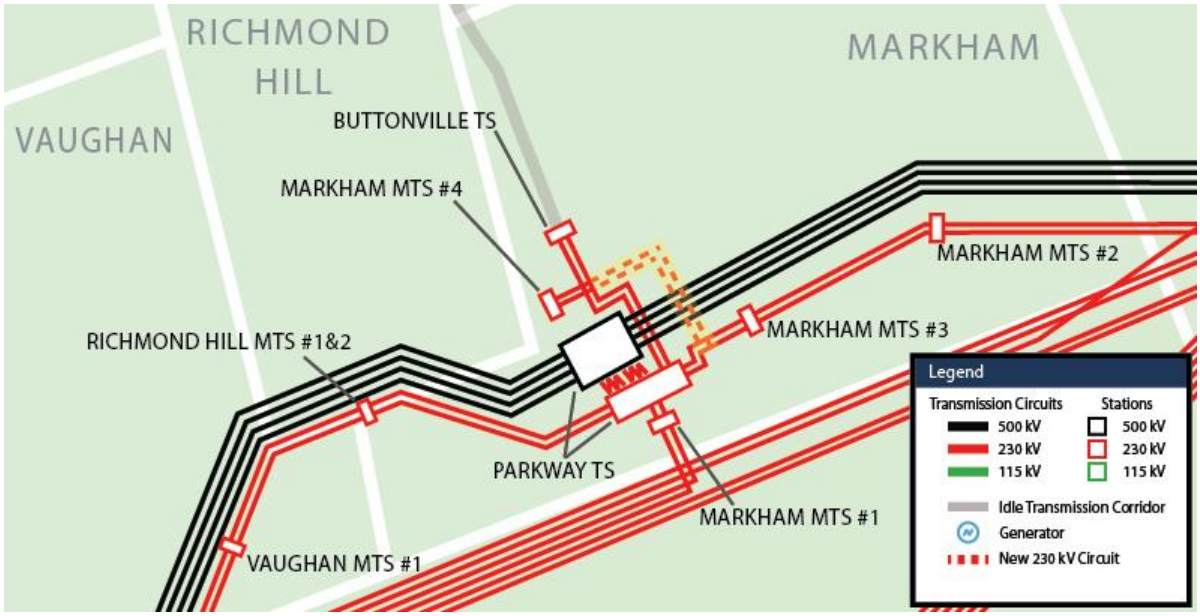
Thermal needs would be triggered when combined load at Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds approximately 450 MW. These needs can be addressed by reconductoring the remaining ~2.7 km section of P45/46 circuits between Markham MTS #4 and Buttonville TS, with an approximate cost of $9.5 million.

The need date for this reconductoring work is when the collective load of Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds 450 MW. To ensure that newly connected stations can make full use of their assets, this work should occur no later than the connection of either Markham MTS #6 or Northern York #2 TS, whichever comes first. However, it can often be challenging for facility owners and operators to manage outages required during reconductoring work. As a result, this work may be advanced at Hydro One's discretion, particularly if project efficiencies are identified from pairing this work with the reconductoring of the adjacent Parkway TS to Markham MTS #4 section of P45/46.

7.4.2.5 Markham MTS #4 radial tap

After addressing thermal needs with the reconductoring described above, the connection and loading of longer-term stations to the P45/46 circuits would still cause security needs to emerge when total load exceeds 600 MW. To address security needs, a new radial transmission circuit could be extended from the existing transmission corridor in the south (adjacent to Highway 407), to connect Markham MTS #4, and remove it from the remaining P45/46 circuits. This would increase the LMC of the area by roughly one station worth of load. This is shown conceptually in Figure 25.

Figure 25| Possible Radial Tap of Markham MTS #4



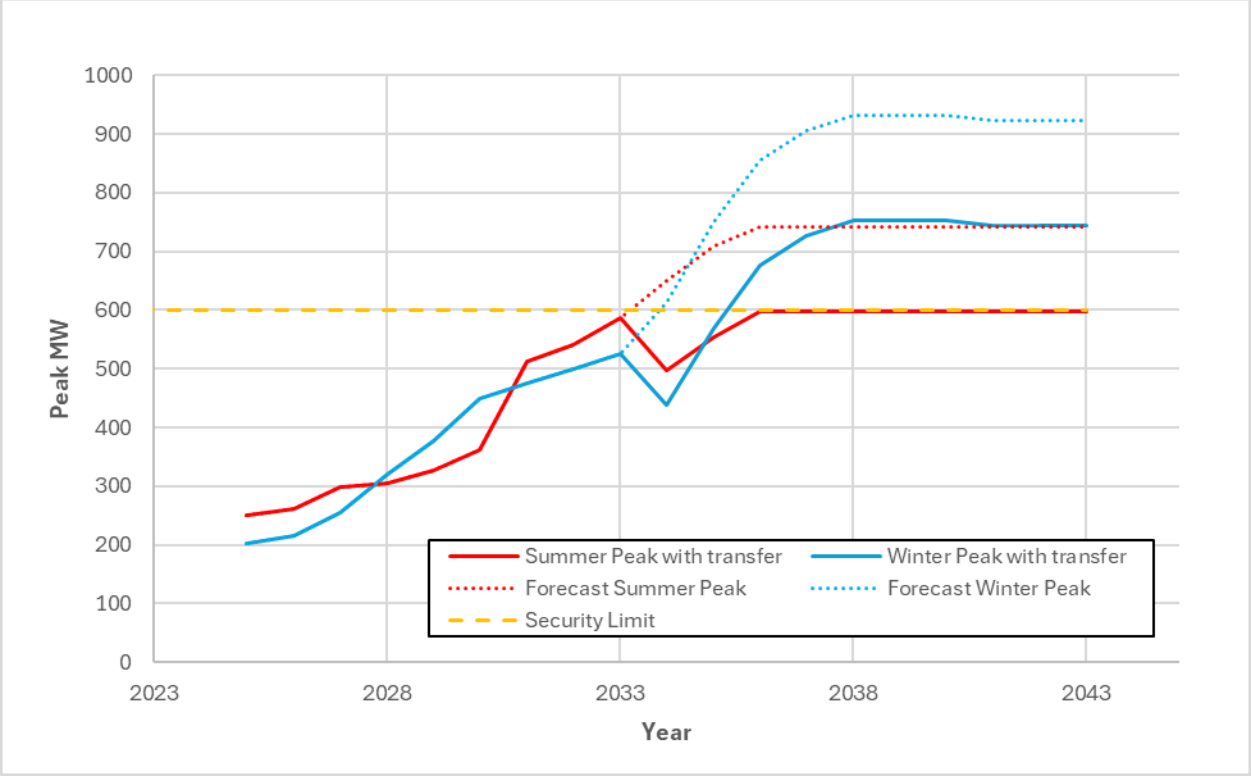
Markham MTS #4 is the preferred station for tapping off with a new transmission connection, as it is located close to alternate transmission points, with potentially as little as 1.5 km of new transmission required. Several potential connection points for this extension exist, including direct connection to Parkway TS, and tapping of the existing C35/36P circuits. The latter option is currently preferred as it would be significantly less costly than a connection within Parkway TS, which would incur additional upgrade costs to existing bulk system infrastructure at the station due to space constraints. The estimated present-day cost of the Markham MTS #4 tap from C35/36P circuits is $9 million. Making a

direct connection within Parkway TS, while offering improved reliability by reducing the number of stations served by a single transmission asset, would likely incur a minimum additional cost of $70 million to upgrade existing Air Insulated Switchgear (AIS) to Gas Insulated Switchgear (GIS). Both candidate transmission connection points can be accommodated within existing transmission corridor right of ways.

It is recommended that this work be undertaken to coincide with the connection of either Markham MTS #6 or Northern York TS #2, whichever is ultimately required first. This will allow LDCs to make full use of connection facilities once they become available. Identification of a preferred connection point for the Markham MTS #4 radial tap should be reevaluated during the next planning cycle, as development work is not expected to be required within the next 5 years. Cost assumptions related to different connection points may change in the interim based on bulk planning outcomes and/or upgrades required for new customer connections. This also provides time to monitor demand growth, and to implement measures aimed at managing the demand growth in order to defer the need for new infrastructure as long as possible.

Figure 26 shows the impact of removing Markham MTS #4 from the P45/46 circuits (notionally shown in year 2034) enables the remaining stations to be loaded up to the forecast summer peak.

Figure 26| P45/46 Circuit Loading



In the event that higher winter peaks begin to emerge in the long term, violations of security criteria are possible, with peaks potentially reaching 740 MW. If forecast winter peaks begin to emerge, NWA may provide a good solution to address periods of time where there is a risk of exceeding security limits, particularly as resources would only be required for short periods of time over the year.

7.4.3 Options to Address Northern York Needs

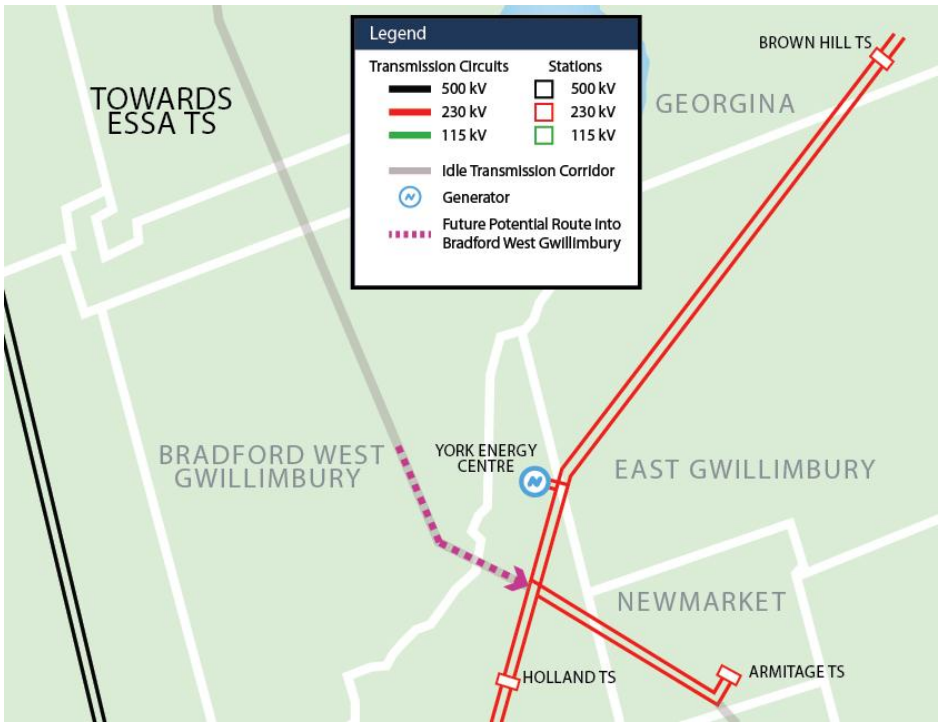
Preferred options to address longer term needs in Northern York will ultimately depend on the location of future Northern York step down stations, and whether YEC is assumed to continue commercial operation after 2035. Potential options are described below, although actions will not need to be taken to advance solutions at this time.

7.4.3.1 Northern York TS #3

As outlined in section 6.3.1.1, by the mid 2030s, growth rates in Northern York are expected to require a new step-down station to serve growing customer demands approximately every 4 years. This could further increase if large loads associated with major customer connections begin to emerge. The general preferred location for Northern York TS #1 and #2 has already been identified based on existing capacity limitations and anticipated high growth areas (the general vicinity of Holland TS and future Markham MTS #6, respectively). The preferred location for Northern York TS #3 is not yet known but would likely be in the general vicinity of Holland Marsh junction, where it would be located to accommodate growth throughout the communities of King, Newmarket, East Gwillimbury, and Bradford West Gwillimbury. This is because these communities are the furthest from the planned location of Northern York TS #2, so, as with Southern York region today, it is reasonable to assume alternating new stations between the east and west sides of the Northern York area.

An existing, idle transmission corridor currently stretches from the Holland Marsh junction, northwest through Bradford-West Gwillimbury, and ultimately through Simcoe County to connect with the existing Barrie TS and planned Innisfil TS (stations are within the South Georgian Bay/Muskoka regional planning area).

Figure 27| Conceptual route along idle corridor between Essa TS and Holland Marsh JCT



Making use of this corridor should be evaluated closer to the Northern York TS #3 need date to determine if the incremental benefit of providing step down capacity closer to load growth centres would offset the increased transmission cost. These benefits could include lower distribution infrastructure costs, lower connection costs for large customers, and higher reliability and power quality depending on the future areas of highest demand growth. Having this station on a separate transmission radial link could also potentially improve future capacity constraints on the remaining network circuits in Northern York (H82/93V and B88/89H), but this would need to be evaluated when actual longer-term supply and demand conditions are better known.

7.4.3.2 York Energy Centre Continued Operation

As described in section 6.3.2.1, the phase out of YEC following its contract expiry in 2035 would introduce a sudden 400 MW shortfall of local capacity in Northern York region. The supply gap would be in addition to organic load growth already defined in the load forecast. Meeting a sudden supply requirement of this magnitude would either require similar sized generation to take its place, or new transmission to bring capacity into he same general area where generation is lost.

In order to replace the existing, single cycle gas supply, a generation option would need to have similar operational characteristics as YEC today. This means the ability to rapidly ramp up operation, adjust generation levels to match local demand levels, and operate continuously throughout periods of peak demand, which can last for several hours in a day, and last several days in a row. Intermittent generation sources, such as solar and wind, would not be suitable alternatives due to significant land requirements to account for lower capacity factors for these generation types. Pairing

with batteries would also pose challenges, as the size of batteries required would need to account for worst expected duration of needs over several years, which would not be economic since these conditions are by definition rare events.

It is important to note the that the local requirements to operate YEC (or a similar sized and technology type resource) are only triggered for short periods of the year. This would include hours where local demand is at its highest, or during planned or emergency system outages. While fully offsetting the need for the full 400 MW of available capacity would be very challenging without significant transmission infrastructure to replace this shortfall, adding additional energy sources, such as a Battery Energy Storage System (BESS), would lower the number of hours of the year in which YEC would be expected to operate.

Local communities have consistently indicated a strong preference for lowering greenhouse gases (GHG) emissions released in the area, where achievable with minimal disruption to the surrounding agricultural land use. Capital Power, the owner of YEC, has recently installed a 132 MW BESS to one of the two yards that YEC operates out of. The existing BESS, while able to lower expected GHG from normal operation, does not have a significant impact on local capacity or reliability needs.

If a second, similarly sized BESS were connected to the B89H circuit (either at YEC, or elsewhere on the circuit section), the combined impact of the two BESS units would improve system reliability performance, as at least one could be assumed in service under all contingencies in which either B88H or B89H remain operable. The reliability benefit for adding a second, identically sized BESS within the B89H corridor would be equivalent to approximately 60 MW of reliable local capacity, after accounting for typical operational profiles of BESS technology.

However, the supply capacity increase from this second BESS would not be sufficient to offset near term needs, nor would it have an impact on longer-term step-down station capacity needs. For that reason, it is not included as a recommendation in this study. A combination of short circuit and congestion issues also currently prevent new local resources, including BESSs, from connecting in this area. However, if these issues are resolved in the longer term, this project, or other similar sized generation projects, could help defer longer term needs in the area while reducing the amount of time YEC could be expected to run in the near term, thereby lowering GHG emissions within the area. This makes it a potentially higher value location for siting BESS technologies within York Region, when considering reliability and environmental factors. These benefits would be unique to generation sources which are dispatchable, non emitting, and able to be connected to the B88/89H (preferably B89H) circuits.

7.4.3.3 New Northern York transmission supply

In the event that YEC is phased out following its contract expiry in 2035, and equivalent generation is not located in the same general area, it would trigger the need for a new transmission circuit to deliver capacity into Northern York. A typical double-circuit 230 kV line can transfer at least 600 MW of power, though design factors can influence total capacity. Planning this type of infrastructure would require consideration of the initial supply point, the termination, and route between these two points. For a supply point, the anticipated and nearby Kleinburg TS would provide an excellent source of bulk power and given it is expected to come into service in the early 2030s, would likely have

more than sufficient capacity for this project. As a termination point, a connection in the same general vicinity as YEC, or at a minimum on the B88/89H circuits would be preferred. This would ensure that new capacity can push against the typically limiting flow away from Kleinburg TS along H82/83V. An ideal connection point would be a new Switching Station (SS), described in the section below, which would link the existing H82/83V circuits with B88/89H, while creating new terminations for the Armitage radial pocket. Having a supply path into this SS would ensure each of the supply points emanating from this station could have a redundant source of supply under multiple configurations and contingencies.

Based on an initial review of the existing corridor between Kleinburg TS and the Holland Marsh area, a new transmission right of way would need to be identified and land acquired to enable this connection. The first section of a proposed corridor could make use of the planned Kleinburg – Kirby transmission link, adjacent to the future Highway 413. Sufficient land is being set aside to enable two double-circuit transmission lines along this route. The first, described in section 7.3.2.2, is expected to be developed in the near term, while the space allocated for the second could be leveraged here. This would allow for a partial new corridor between Kleinburg TS and the approximate intersection of Kirby and Kipling. The remaining ~23km to the Holland Marsh area has an existing transmission line, but there is insufficient land along this corridor to enable a second transmission line. Additionally, there are several points along this corridor where buildings and other geographic features unsuitable for transmission use are immediately adjacent, meaning acquiring new land adjacent to the existing line is either not preferable, or infeasible. As a result, a new route would need to be identified, largely through King township. Given the complexities of siting transmission, namely requiring a linear corridor, with fixed start and end points, and compatible adjacent land uses for the entire route, this could be a costly and disruptive undertaking for the community.

No actions or recommendations are required at this time. However, if YEC is assumed to come out of service in 2035, work should begin no later than 2028 to identify land suitable for a new transmission corridor and initiate development work. Although no site-specific analysis has been undertaken to produce formal cost estimates, typical new corridors of this size, including transmission infrastructure and real estate costs, could be $200-300M.

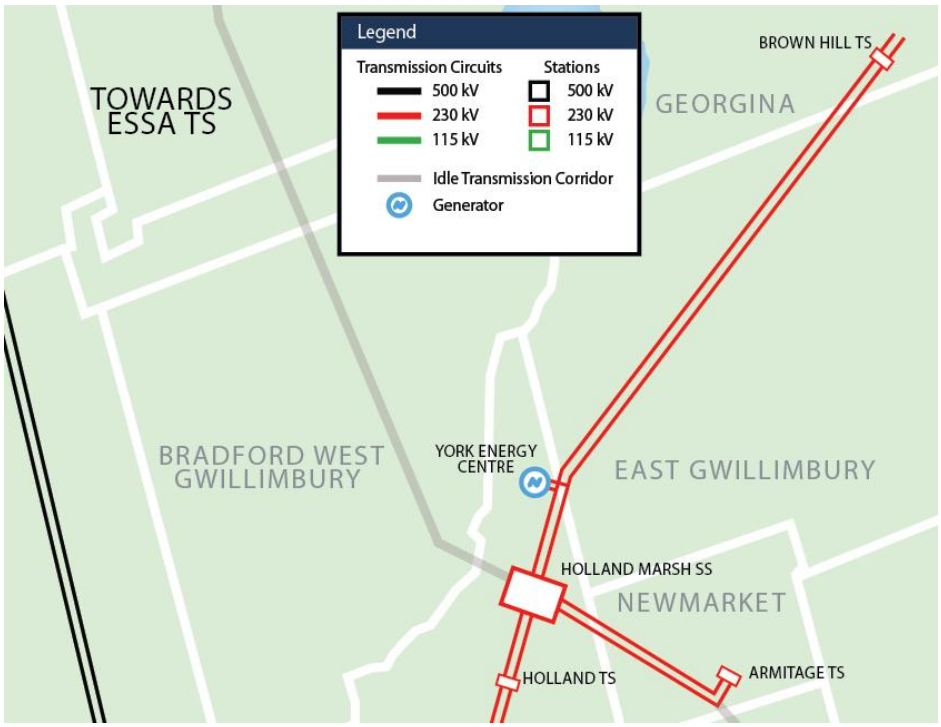
7.4.3.4 Holland Marsh Switching Station

As described in section 7.5.3.1, the connection of a third Northern York TS along the Claireville to Minden corridor will trigger a security need regardless of whether it is connected to the H82/83V or B88/89V circuits. In addition to the security needs triggered, this section of the grid has been cited by operators as posing significant challenges due to the presence of two sets of inline breakers, and a major system resource facility (YEC). Sectionalizing the existing circuits through a Switching Station (SS) would greatly streamline the operational characteristics, while enabling the connection of Northern York TS #3, and eliminate the most limiting breaker failure contingencies currently affecting the area.

A long-term switching station configuration would be positioned at the existing Holland Marsh junction, to allow for separate circuit termination for the existing H82/83V, modified B88/89H circuits (only the section north of the Armitage junction), and a new, separate radial pocket for Armitage TS. Circuit positions should also be made available for the connection of any future radial circuits

required for supply to the Bradford-West Gwillimbury area, and for connection of any new supply transmission line which may be required in the long term, as outlined in Section 7.4.3.3.

Figure 28| Potential future location of Holland Marsh SS



The ultimate configuration of the SS is outside the scope of this study but should be investigated to eliminate the possibility of a common breaker failure triggering simultaneous loss of one H82/83V circuit and one B88/89V circuit. This would eliminate the most limiting breaker failure contingency. If a longer-term connection line into West Gwillimbury is ultimately developed to connect the future Northern York TS #3, an initial preferred switching station arrangement could assume that line terminations are alternated between network lines (B88/89H and H82/83V) and radial lines (Armitage tap, West Gwillimbury Tap).

At this time, the development of a Holland Marsh Switching Station is not required. The current demand forecast suggests that Northern York TS #3, and as a result Holland Marsh SS, would be required in the mid 2030s. However, these assumptions should be revisited during future studies based on actual growth rates, preferred location for future stations, and ultimate connection arrangements. Hydro One has indicated that existing land rights are expected to be sufficient to accommodate this facility when required, with no additional acquisitions required. Switching Stations of this size, including all associated switchgear and breakers, typically cost $200-250 million.

7.4.3.5 Reconductoring H82/83V

As described in section 7.3.2.2, reconductoring of the limiting section of H82/83V between Claireville TS and Vaughan MTS #4 is not a viable option, as the existing corridor is too narrow, and development too close, to allow the work to be completed. However, development north of the proposed Kleinburg-Kirby connection point along H82/83V is significantly less dense. Based on a

review undertaken by Hydro One, reconductoring the remaining section between the Kleinburg-Kirby link and Holland Marsh junction is likely feasible.

Following completion of the YEC station service project and the Kleinburg-Kirby link, additional load meeting capability in Northern York is not expected to be required until an additional step-down station is required (notionally Northern York TS #3), and/or following the potential retirement of YEC.

The benefit provided by this reconductoring would depend on the longer-term configuration of the system, including location of demand, supply, and any new infrastructure such as switching facilities. Where thermal limits along the H82/83V circuits are found to be limiting, reconductoring this section could potentially increase LMC by providing improved capacity into a future Holland Marsh SS.

7.5 Opportunities for Non-Wires Alternatives

7.5.1 Large-scale Non-Wires Alternatives

Transmission-connected resources such as large-scale solar, wind, BESS or a combination of these resources were found not adequate to resolve the supply capacity needs covered in Section 6. This is mainly due to 1) connection restrictions in the area due to short circuit limitations at Claireville TS and congestions on the circuits covered in the needs 2) the large magnitude of land required to meet the supply capacity needs of each region sufficiently to defer wires reinforcements.

Installing large transmission-connected resources also do not resolve the station capacity needs in the region, especially in Northern York and the Markham area where downstream feeders cannot viably connect to the system unless new step-down stations are implemented. It is expected that the near-term recommendations described in Section 7.3.2.2, along with the required bulk upgrades described in Section 8.1, will help enable the connection of some resources by resolving the short circuit limitations of Northern York, but congestion constraints will remain in the area, and short circuit issues remain in Southern York.

7.5.2 Demand Side Management

Incremental eDSM can help manage the demand until the next major grid reinforcement or step-down station would be required to cater to the large supply capacity needs. The table below provides a year over year cumulative breakdown of the incremental eDSM potential available per subregion above and beyond that already captured in the IRRP demand forecast.

Table 10| Estimated Incremental eDSM Potential (Cumulative MW) by Subregion

	Northern York	Kleinburg subsystem	Southern Vaughan-Richmond Hill	Markham and Area
2025	18.4	7.7	10.3	9.9
2026	26.3	10.7	13.3	13.4
2027	44.0	17.6	20.3	23.8
2028	35.1	14.1	16.9	18.0
2029	52.5	20.7	23.3	29.1
2030	60.2	23.5	26.8	34.4
2031	70.3	28.1	35.7	45.3
2032	82.5	33.9	47.8	55.9
2033	92.8	38.9	58.9	66.8
2034	103.1	42.5	68.0	78.2
2035	123.9	46.9	76.8	95.5
2036	112.8	44.5	71.7	86.9
2037	141.4	49.6	80.5	100.5
2038	161.0	52.4	84.9	105.7
2039	177.0	55.2	89.1	113.0
2040	190.9	57.6	92.8	123.0
2041	200.0	59.4	96.1	131.5
2042	**211.6**	**61.5**	**99.3**	**137.4**

8 South and Central Bulk Study

IESO is currently also undertaking a bulk study focused on the Southwestern and Central regions of Ontario, particularly along the Windsor to Hamilton corridor as well as the urban centers in the GTA.

This bulk study is closely linked to the GTA North IRRP and will be key in enabling some of the near-term recommendations discussed above.

Some of the key linkages from the bulk study to this IRRP are as follows:

- Upgrading station (Kleinburg TS) from 230kV to 500kV to support provincial and local needs
- Building an additional circuit from Essa (Barrie) to Kleinburg TS to strengthen electricity flows north/south
- Improving bulk system supply from east GTA towards Parkway TS to help support growth in GTA North
- Determining transmission required to enable decreased bulk system reliance on YEC
- Protecting strategic corridors for future infrastructure to support economic development and community growth

8.1 Bulk Considerations for Enabling the Kleinburg-Kirby Transmission Link

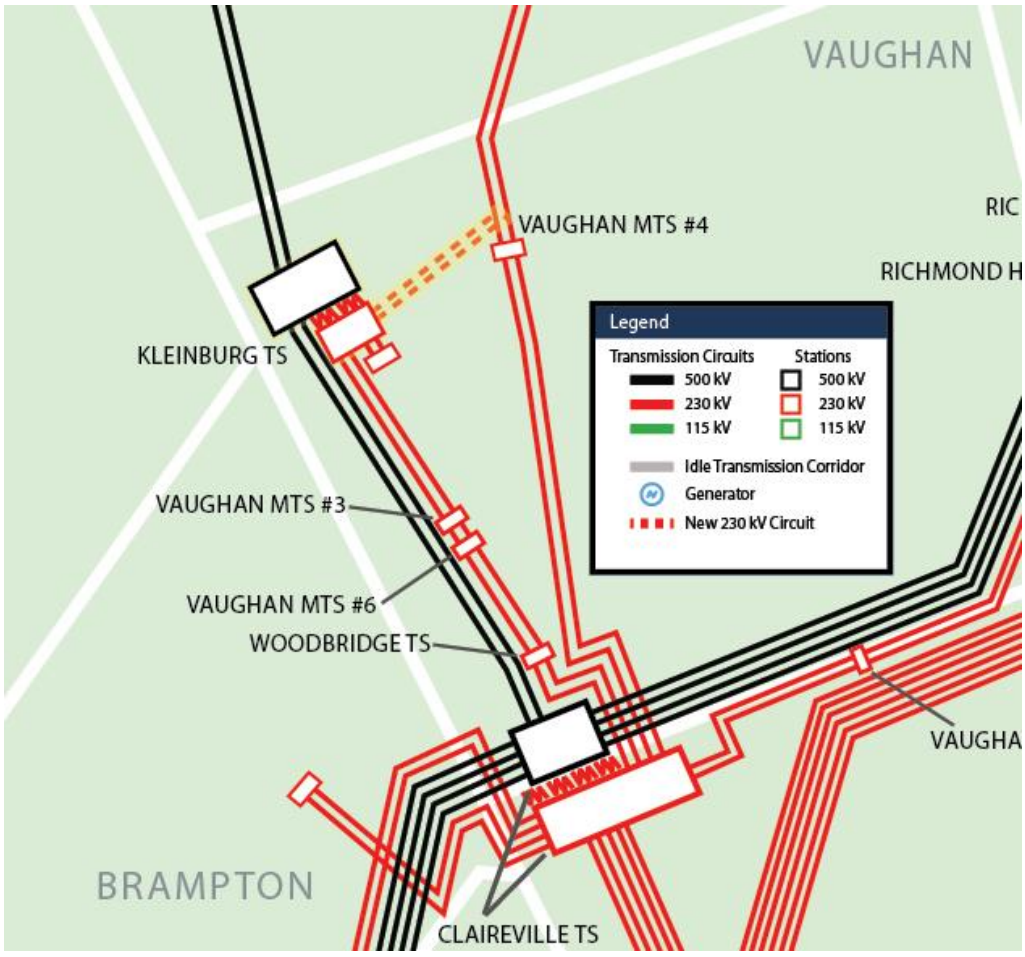
Placing the Kleinburg – Kirby link in service discussed in section 7.3.2.2 will require additional capacity to be available at Kleinburg TS to supply northern York. In the absence of a new supply source, the existing Kleinburg radial tap would become thermally overloaded north of Claireville TS, as the V43/44 circuits would have to carry all existing supply for the local pocket, as well as incremental demand for customers in northern York.

The existing Kleinburg TS, located at the northernmost point of the V43/44 circuits, is currently operated as a step-down station primarily providing distribution supply to customers in Vaughan, Brampton, and Caledon. However, when this site was originally developed, its access to both the regional 230 kV and bulk 500 kV transmission network made it a suitable candidate as a future bulk supply point. Enough land was acquired when developing this station to accommodate additional switching and autotransformer facilities to create a 500kV to 230 kV bulk supply point once required. Based on the current needs for supplying local growth, and broader bulk system benefits identified through a separate bulk planning process, it is recommended that the development of Kleinburg TS as a bulk supply point proceed.

In order to manage higher order contingency scenarios required for the bulk system, three 500 kV to 230 kV autotransformers will initially be required at this site. Space should be set aside to enable the long-term connection of a fourth autotransformer, as a final build out option. Supply to the new autotransformers is to be accomplished through bisecting and re-terminating the existing two 500 kV circuits between Claireville TS and Essa TS. This will require a single 500 kV bus at Kleinburg TS with an initial four 500 kV connection points – two connecting Kleinburg TS to Claireville TS, and two connecting Kleinburg TS to Essa TS.

On the 230 kV yard, space should initially be set aside for six circuit terminations. These would consist of the original two V43/44 circuits, the new double-circuit Kleinburg-Kirby link, and a double-circuit tap to directly supply the existing Kleinburg TS step down station (referred to as Kleinburg DESN hereafter for clarity). Providing a separate connection for the existing Kleinburg DESN would address potential security needs on the Kleinburg radial tap by reducing the amount of capacity supplied by the V43/44 circuits (see section 6.3.3.2). Selecting Kleinburg DESN for direct connection to the 230 kV bus work would minimize connection costs as the station is already located within the facility. In addition to these initial six 230 kV termination points, space should also be set aside for a minimum of four additional positions, to accommodate a potential longer-term need for a new double-circuit 230 kV line into northern York, and a double-circuit 230 kV line spanning westward to supply local demand in northern Brampton and southern Caledon. This latter route would also make use of the planned transmission corridor adjacent to Highway 413. The notional layout of these new facilities is provided below:

Figure 29| Future Kleinburg TS and Kleinburg – Kirby transmission link



This configuration should be considered preliminary at this point and is provided to aid in system evaluation and preliminary site design. Review and further recommendations for the configuration and layout of the Kleinburg TS 500 kV and 230 kV station yards should be carried out by Hydro One as part of the Regional Infrastructure Planning (RIP) process, and final design through the applicable approvals process.

Given that Kleinburg TS is owned and operated by Hydro One today, the development of the Kleinburg TS bulk supply station is not suitable for competitive procurement.

Providing capacity at Kleinburg TS through new local generation, as opposed to creating a new bulk supply point, is not preferred for several reasons.

1. Short circuit levels at Claireville TS are elevated today and will require operational changes at the 230 kV level in order to accommodate additional supply (transmission or generation) at Kleinburg TS.
2. Using a generation source of supply, as opposed to transformers, would require continuous operation and significant load following capability to match local demand. These types of operational requirements are not practical or cost effective for a local system.
3. Transformers are preferred as they provide the benefit to the overall bulk transmission system. Introducing this new supply point in the GTA will provide needed offloading for Claireville TS, enabling growth and the connection of some local resources in the surrounding regions including City of Toronto and Regions of Peel and Halton. while improving long term ability to disperse flows into Essa towards the higher demand centres to the south.

The estimated cost for the development of Kleinburg TS, including all associated switching gear, autotransformers, and reconfiguration of the existing 500 kV system, is approximately $400 M. This station is needed in the near term to accommodate regional growth as well as primarily to serve a bulk system function by managing supply between the existing Claireville TS bulk supply point to the south, and the new supply point to the north, which is better located for accommodating growth throughout northern Halton, Peel, and York regions. The Kleinburg to Kirby link is likewise performing a bulk system function by allowing supply from the new Kleinburg TS to be accessible for regional customers.

Timelines for the implementation of the Kleinburg-Kirby link, and bulk system build out of Kleinburg TS, would ideally align with the proposed in-service date of Northern York TS #1, to ensure infrastructure can be loaded to its full capacity once available. Given typical rates at which new stations are loaded, however, the connection of Northern York TS #1 could be advanced, so long as total loading on the Claireville TS – Brown Hill TS corridor remains under 848 MW, assuming the YEC station service issue has been resolved. This loading level is roughly equivalent to Vaughan MTS #4, Holland TS, and Armitage TS at their full respective LTRs[7], Brown Hill TS loaded at its current summer peak, and the new Northern York TS #1 loaded to 38 MW. Loads of these levels are typical for the first one to two years of a newly in service station. Above this load level, more frequent arming of the existing RAS would be required until the transmission solution has come into service.

8.2 Bringing Bulk Supply from East GTA towards Parkway TS

New generation resources located near Darlington Nuclear Generation stations will become available in early to mid 2030s. The IESO has previously identified a need for a double-circuit going west towards the GTA as an early action to supply the urban centres in the GTA, including the Region of

[7] Inclusive of new Metrolinx loads in Newmarket

York. Parkway TS has been preliminarily selected to be connected to the new double-circuit to reinforce supply into the region while catering for growing demand in the surrounding regions. This option also makes the best of use of available corridor and station real estate in the GTA. It also allows for reconfiguration of existing loads between the key GTA transformer stations, taking short circuit limitations and supply capability into account.

The study will also consider any system reinforcements required to accommodate the new supply downstream of the station in the GTA 230 kV system.

8.3 Additional Essa (Barrie) to Kleinburg TS

In the longer term, larger bulk flows into Essa will also require a third 500 kV line to be built between Essa TS and the proposed Kleinburg TS. This could be triggered from either higher procurement of generation in northern Ontario (such as through expanded hydro development), or the completion of Bruce to Essa transmission upgrades to incorporate expansion at Bruce nuclear GS or large-scale pumped storage between Bruce and Essa zones. This need is based purely on bulk system considerations, and as such timing for the third line will be outside the scope of the GTA North IRRP.

8.4 Decreasing Bulk System Reliance on YEC in the Long Term

As discussed in Section 6.3.2.1, should YEC be phased out following its contract expiry in 2035 or at its eventual retirement at the end of its life cycle, and equivalent generation is not located in the same general area, new transmission infrastructure may be required to cover the capacity shortfall. The bulk study is aimed at studying the impact of the absence of YEC at a wider system level and any potential reinforcements required to adequately supply the region.

8.5 Protecting Strategic Corridors

The IESO is taking early action to identify and protect strategic corridors to enable the long-term infrastructure discussed in the sections above and beyond to enable and support electrification, residential and economic intensification. Three key studies are identified in high-growth areas, including York Region, where land is limited and electricity systems are nearing capacity:

- **Parkway Belt West Corridor**: Exploring future high-voltage transmission lines and transformer stations to support GTA growth and to enable new generation resources.
- **Barrie to Markham Corridor**: Preserving land for a future transmission line to further link Northern and Southern Ontario, to enable growth in Northern Ontario and to supply Southern Ontario with diversified resources.
- **Northwest GTA Corridor**: Refining plans near Highway 413 to support future infrastructure in York, Peel, and Halton.

9 Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the GTA North IRRP.

9.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 30| The IESO's Engagement Principles



9.2 Engagement Approach

To ensure that the Plan reflects the needs of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the GTA North engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback;

- Encouraging participants to visit the Powering the GTA website, dedicated to exploring electricity needs and solutions across the GTA;
- Timely and targeted discussions with municipalities and letters prepared for Mayors and Councillors to help inform the engagement approach for this planning cycle;
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions; and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 9.4).

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the GTA North Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the GTA North Scoping Assessment Report finalization. A public webinar was held in September 2023 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in October 2023, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings then began to involve municipalities in the region to ensure growth and development plans have been accurately captured in the Technical Working Group's draft demand forecast and solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the GTA North Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar. The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during public engagements primarily focused on:

- Significant population growth and economic development projects across the region;
- Aligning infrastructure with community infrastructure development;
- Interest in leveraging existing and local generation;
- Alignment of electricity planning with local priorities, such as community and energy plans; and
- Exploring alternative solutions, such as non-wire options, to meet the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to GTA North Region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with the significant forecasted growth and development both within specific municipalities and the region more broadly (e.g. significant population and employment growth shared by the City of Richmond Hill, constrained land use shared by the Cities of Richmond Hill and Markham, and capacity constraints shared by Bradford West Gwillimbury). Another key priority was to understand community perspectives on keeping York Energy Centre (YEC) in service past the 2035 contact expiration, which received general support from municipalities and stakeholders highlighting concerns for the remaining supply gap without the facility. These insights have been valuable to the IESO – as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's GTA North engagement webpage.

9.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on its planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the lower-tier municipalities in York Region to share key developments and to provide an opportunity for municipal feedback on the forecasted regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal and community electricity needs and priorities, establish new relationships, and provide opportunities for ongoing dialogue beyond this IRRP process. Additionally, the IESO led

council outreach that included letters prepared for mayors and councillors, and one-on-one councillor meetings to provide elected officials with updates on electricity planning developments, and to provide an opportunity for discussion.

Through these discussions, valuable feedback was received and incorporated in the final IRRP recommendations, including:

- The Town of Stouffville recommended sharing the methodology on how the demand forecast is calculated, including the different variables that are considered.
- The Township of King, the City of Markham and the City of Richmond Hill expressed the need for early and detailed coordination with municipalities to ensure electricity planning aligns with land use policies and congested municipal right-of-ways (ROWs).
- The City of Markham emphasized their preference for utilizing existing station and transmission infrastructure corridors to avoid expanded or new corridors, reducing impact on development and adjacent communities.
- The City of Richmond Hill, and the Town of Whitchurch-Stouffville requested sharing a layout of the power distribution network and detailed mapping of locations for future infrastructure requirements to understand compatibility.
- The Cities of Richmond Hill, Markham and Vaughan detailed significant population and development growth projections in their cities to ensure it is captured in the demand forecast.
- Station capacity concerns were raised in Bradford West Gwillimbury at their Holland TS, and in the City of Vaughan along the Yonge/Steeles corridor.
- Several municipalities highlighted their energy, and sustainability plans and encouraged consideration for non-wire alternatives as solutions in the IRRP in order to align with their net-zero and decarbonization targets.
- King Township and the City of Markham support keeping YEC in service considering the facility already exists and reduces the need for widespread transmission infrastructure and suggest exploring deep retrofits that align the facility with climate goals.

9.5 Engaging with Indigenous Communities

The IESO remains committed to ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in the GTA North (York Region) and provide opportunities for input, the IESO invited Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use to participate in engagement efforts that included webinars and meeting discussions (virtual or in-person).

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions across Ontario.

10 Summary and Conclusion

The York Region Integrated Regional Resource Plan (IRRP) identifies electricity needs across the region over the 20-year planning horizon from 2024 to 2043 and recommends a coordinated set of actions to address these needs in the near term to enable growth in the region and identifies potential options which may be required in the longer term. The IESO will continue to participate in the Technical Working Group during the next phase of planning, the Regional Infrastructure Plan (RIP), to support implementation and ensure alignment with broader system planning.

In the near term, the Technical Working Group recommends immediate action to address station and supply capacity needs in Northern York, Markham, and Richmond Hill. This includes the development of new step-down transformer stations (Northern York TS #1, Markham MTS #5, and Richmond Hill MTS #3), a new 6-7 km transmission line along the future Highway 413 corridor in Vaughan, reconductoring of existing transmission circuits in Markham, and sectionalization devices to address security needs. To improve reliability, operational measures including reconfiguration of York Energy Centre's power supply, and targeted incremental eDSM are also recommended to manage reliability risks and defer longer-term infrastructure needs.

In the medium- to long- term, the Technical Working Group recommends planning for additional step-down transformer stations (Northern York TS #2 and #3, Markham MTS #6, Vaughan MTS #5), and transmission enhancements to ensure these stations can be reliably supplied. This includes extending the existing Markham transmission line approximately 7 km into northern Markham, to enable the connection and supply of new step-down stations to serve customers in the vicinity of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville. Longer-term needs associated with Northern York TS #3 will likely require additional transmission upgrades in Northern York, including, at a minimum, a new switching station in the vicinity of Holland Marsh junction. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of a comparably size generator, or a new transmission corridor into Northern York, if this supply source is phased out.

The Technical Working Group will continue to monitor regional developments, including electrification trends, large customer connections, and community energy planning. Opportunities to target incremental eDSM and non-wires alternatives will be evaluated to defer infrastructure needs where feasible. The Working Group will meet regularly to track progress, assess changing conditions, and update the plan as needed. Should significant changes in assumptions arise, the IRRP may be amended or a new planning cycle initiated ahead of the standard five-year schedule.

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Powering Tomorrow.

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX F
METRO TORONTO – NEEDS ASSESSMENT

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.

<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 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.

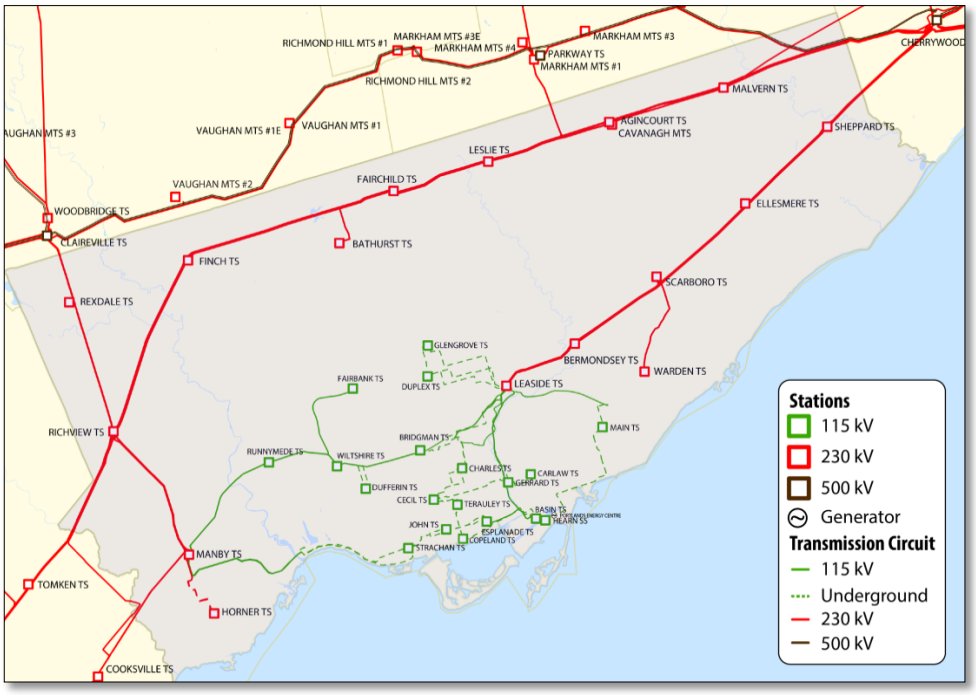


Figure 1: Toronto Region Map

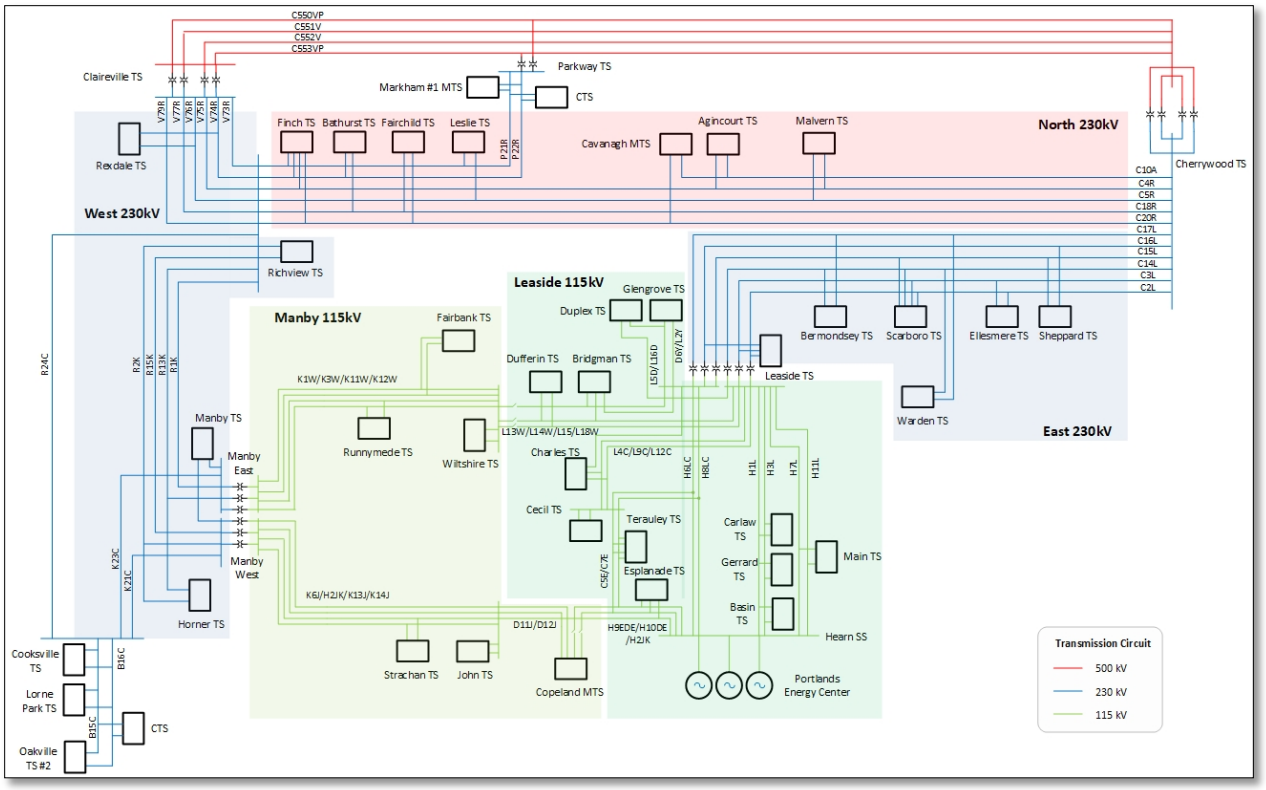


Figure 2: Toronto Region – Single Line Diagram

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
	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.

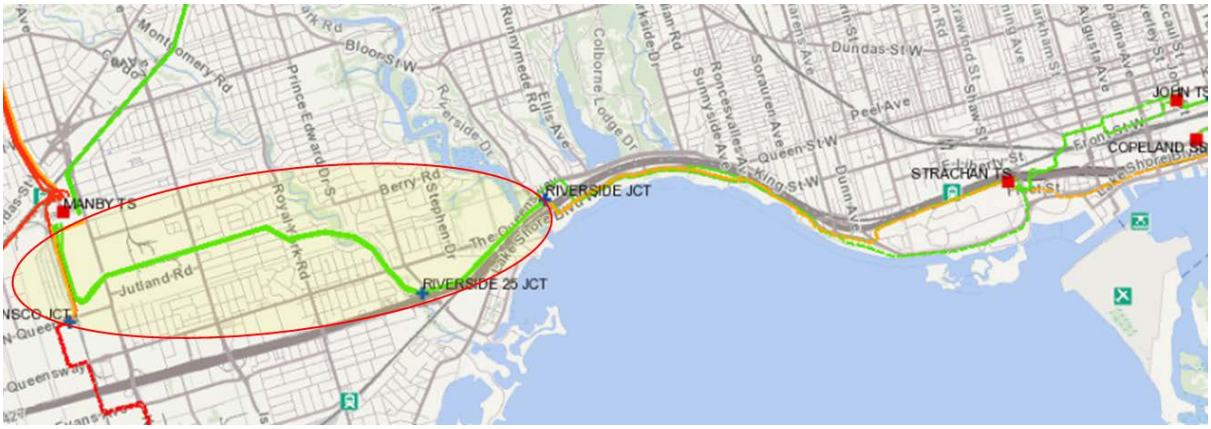


Figure 3: 115 kV Corridor between Manby TS and John TS (overhead section is circled)

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

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 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

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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

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX G
PETERBOROUGH TO KINGSTON – NEEDS ASSESSMENT



NEEDS ASSESSMENT REPORT

Peterborough to Kingston Region

Date: December 20, 2024

Needs Assessment Report

Peterborough to Kingston

December 20, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: Peterborough to Kingston Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston (the "region") and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

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	Peterborough to Kingston Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")
START DATE: September 05, 2024	**END DATE:** December 20, 2024

1. INTRODUCTION

The second Regional Planning cycle for the Peterborough to Kingston Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
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 regional planning cycle to develop a preferred plan; 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The 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 assessment is ten years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. Electrical supply to this region is provided by 3 "Three" major Transmission Stations with Autotransformers that feeds, 10 "Ten" step-down Transformer Stations, 8 "Eight" HV Distribution Stations and 5 "Five" Customer transformer Stations.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecasts.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The needs assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;

b) System reliability needs and 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.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle.

The following needs and projects discussed in the region's second cycle RIP have been completed:

- Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
- Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.

- Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle.

The following needs and projects discussed in the region's second cycle RIP are currently underway:

- Otonabee TS 44kV (Station Capacity) – 8 MW of load transfer will be transferred to Dobbin TS in 2025.
- Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
- Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.
- Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
- Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
- Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
- Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by two new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
- Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
- Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
- B5QK (Long-term Capacity need in 2038) – As recommended in the previous cycle IRRP, IESO will re-evaluate this capacity need in next phases of this Regional Planning cycle, when 20 year load forecast will be developed.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Cataraqui TS (T1/T2)

b) Transmission Station Capacity

- Dobbin TS
- Gardiner TS
- Napanee TS
- Belleville TS
- Cataraqui TS
- Picton TS
- Hinchinbrooke DS
- Frontenac TS

c) Transmission Line Capacity

- 115 kV B1S line under Q6S contingency

d) System Reliability, Operation and Load restoration

- No new System Reliability, Operation and Load restoration needs identified in this NA.

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 investments.

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to new station capacity needs:

- Sidney TS (2031), Otonabee TS 27.6kV (2026), Otonabee TS 44kV (2028) and 115kV P4S (2031).

These needs will be assessed again during the next phases of this Regional Planning cycle.

9. RECOMMENDATIONS

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Needs which do not require further regional coordination.

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

Needs which require further regional coordination.

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028
Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA as potential options in addressing these needs during the IRRP phase.

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Peterborough to Kingston (P to K) Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the P to K Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

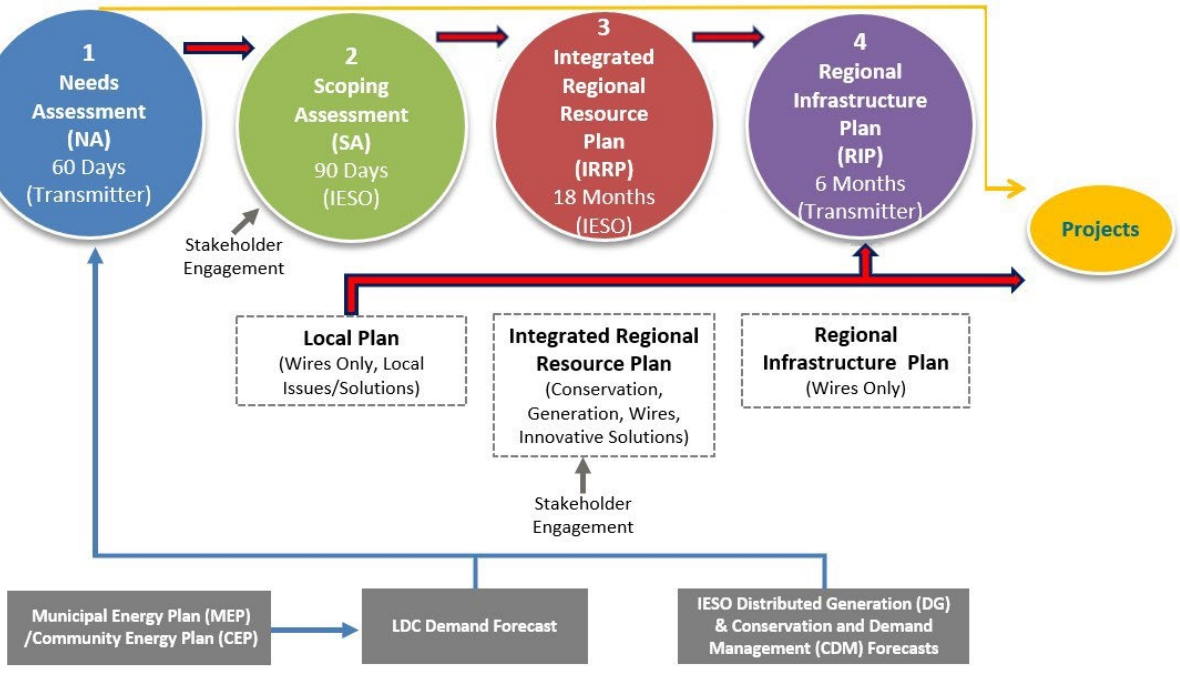


Figure 1: Regional Planning Process

This report was prepared by the Peterborough to Kingston region Technical Working Group("TWG"), led by Hydro One Networks Inc. 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"). Participants of the TWG are listed below in Table 1.

Table 1: Peterborough to Kingston Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Transmission (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Distribution
4	Elexicon Energy Inc.
5	Kingston Hydro Corporation
6	Lakefront Utilities Inc.
7	Eastern Ontario Power Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Peterborough to Kingston region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- 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 and/or no

regional investment is required at this time and the need may be reviewed during the next regional planning 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"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Peterborough to Kingston (P to K) region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. The region includes Frontenac County, City of Kingston, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The geographical boundaries of the P to K region are shown in Figure 2 below.

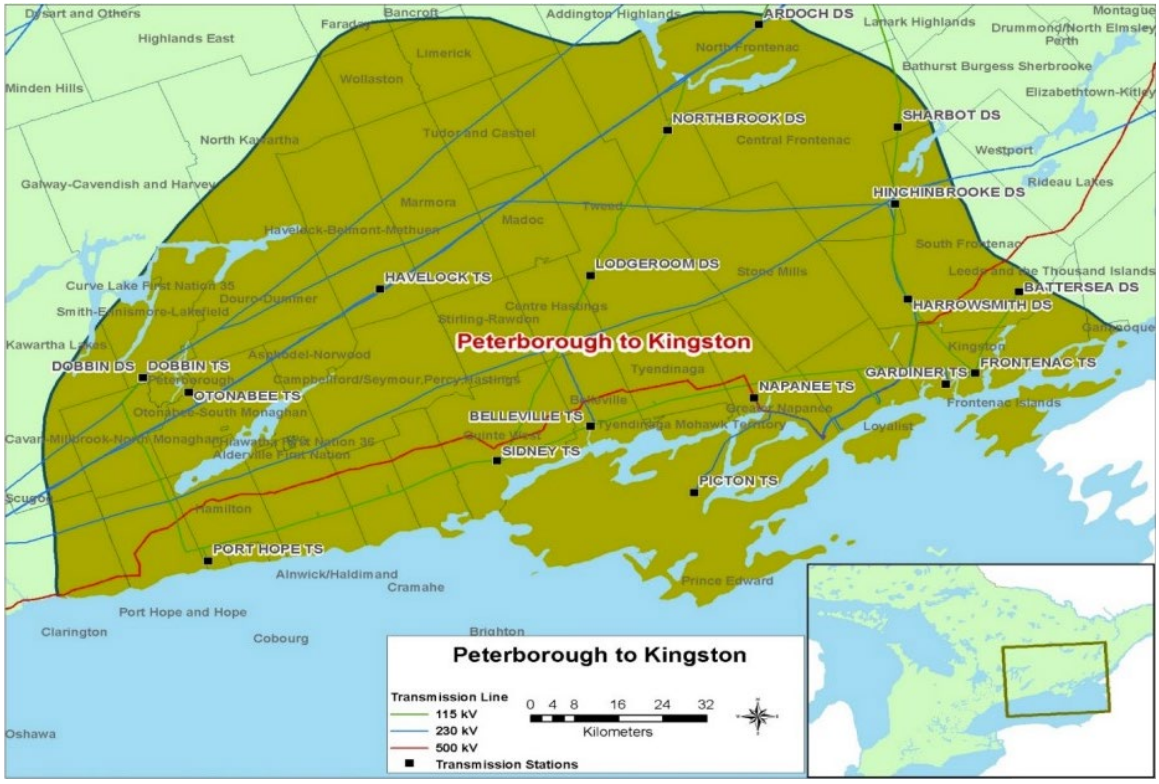


Figure 2: Map of P to K Regional Planning Area

Electrical supply to all five (5) Local Distribution Customers (LDC) listed in table -1 and five (5) Customer Transformer Stations (CTS) in the P to K region is provided by 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS through a 230kV and 115kV transmission lines network. There are seven (7) Generation Stations that generates a total of 3474 MW. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment.

The details of existing facilities in the region are summarized below and depicted in the single line diagram shown in figure 3.

- 500/230kV Autotransformer: Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two autotransformers.
- 230/115kV Autotransformer: Cataraqui TS and Dobbin TS are the two (2) transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Ten (10) step-down transformer stations and eight (8) High Voltage Distribution Stations (HVDS) are connected to 230 and 115 kV lines that supply load in the Region.
- Five Customer Transformer Stations (CTS) are supplied in the Region.
- Seven Generating stations are also connected.

The circuits and stations names are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the P to K Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
P3S, P4S, Q6S, B1S, Q3K & B5QK.	X1H, X2H, X3H, X4H, X21, X22, H23B, H27H, X1P, C27P, T32H, C25H, T22C, P15C & T25B.	Dobbin TS*, Cataraqui TS*, Lennox TS*, Belleville TS, Dobbin TS, Frontenac TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS, Sidney TS, Port Hope TS, CTS -1, CTS-2, CTS-3, CTS-4 & CTS-5.	Seven (7) Generating Stations with total capacity of 3474 MW.

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of P to K region is shown in Figure 3 below.

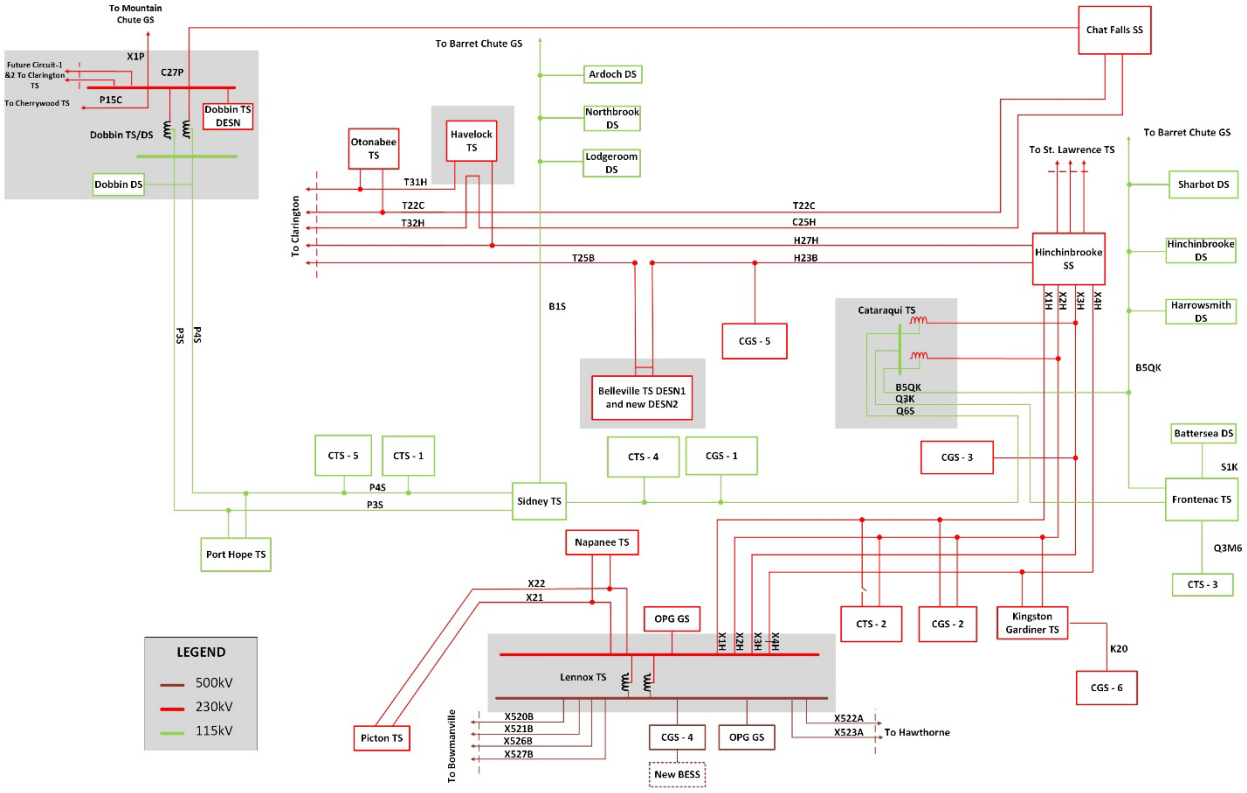


Figure 3: P to K region Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the P to K NA. 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 Oct. 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 regional planning 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). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- P to K 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g., through their MEPs & CEPs).
- Known capacity and reliability need, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the P to K region.
- Captured 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.

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing;" and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer and winter peak loads. Three load forecasts were developed i.e., Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

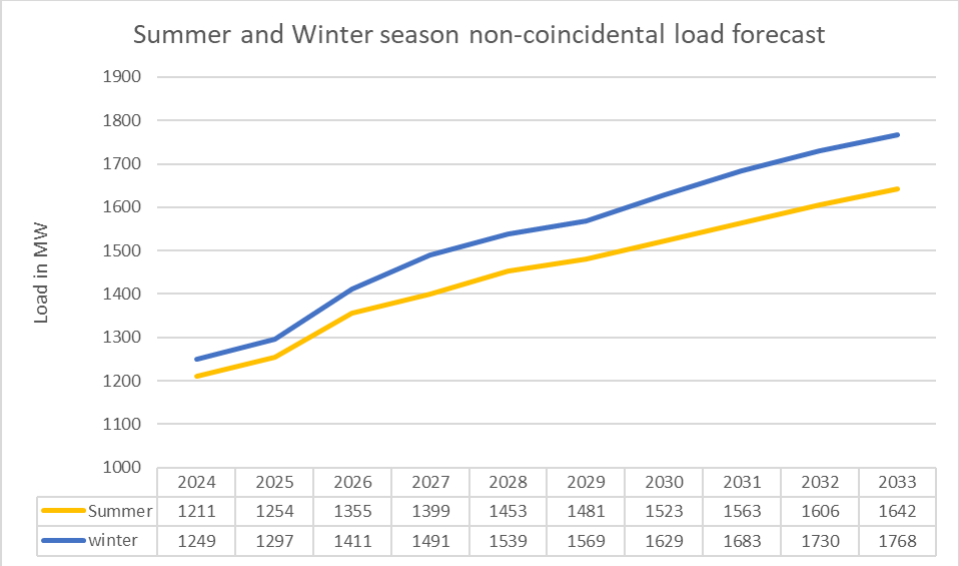
The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2033.
- The Region is winter peaking, but station LTRs are more limiting during the summer season. So, this assessment is based on both summer and winter peak loads.
- Line capacity 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 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 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).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the P to K region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM"), and Distributed Generation ("DG") forecast for the P to K region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the weather corrected forecast starting point. The overall 10-year load forecast growth rate for summer season is 3.6% and 4.2% for winter season. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the P to K region is given in Appendix A. The graphical representation of the regional net non-coincidental load growth for both summer and winter season over the study period is shown in figure 4 below.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	1211	1254	1355	1399	1453	1481	1523	1563	1606	1642
winter	1249	1297	1411	1491	1539	1569	1629	1683	1730	1768

Figure 4: P to K region net summer and winter season non-coincidental load

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not

necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the P to K Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle (Regional Infrastructure Plan ("RIP") report) with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

1. Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
2. Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.
3. Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle. This station capacity need should be further assessed in conjunction with Frontenac TS in the next phases of this Regional Planning cycle.
4. Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
5. Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One

Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.

6. Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
7. Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
8. Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
9. Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
10. Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
11. Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
12. B5QK (Long-term Capacity need in 2038) – As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20 year load forecast will be developed.

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

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or are updated from previous RIP

Need location	Need description/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cataraqui TS	T1/T2 renewal based on asset condition assessment.	7.2	7.1.1
Transmission Station Capacity Needs			
Dobbin TS (T3/T4)	Projected to reach capacity in 2032	New	7.2.1
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028	7.5 & 7.8	7.2.2
Napanee TS (T1/T2)	Projected to reach capacity in 2026	New	7.2.3
Cataraqui TS	Update on need identified in previous cycle RIP	7.2	7.2.4

Picton TS	Projected to reach capacity in 2026	7.6	7.2.5
Hinchinbrooke DS	Projected to reach capacity in 2028	New	7.2.6
Belleville TS	Capacity limitation due to transmission voltage restrictions	7.3	7.2.7
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle	7.4	7.2.8
Transmission Line Capacity Needs			
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency, high hydro output	New	7.3.1
System Reliability, Operation and Load restoration Needs			
No new system Reliability, Operation and Load restoration need is identified in this NA.			

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the P to K Region. The complete list of major HV transmission equipment requiring replacement in the P to K Region is provided in table 4 in this section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD*
Gardiner TS	T1/T2 replacement with like for like 75/100/125 MVA units.	2027
Port Hope	T3/T4 replacement with like for like 50/67/83 MVA units.	2033
Picton TS	T1/T2 replacement with like for like 50/67/83 MVA units.	2026
Dobbin TS	T1/T2 Autotransformers to be replaced by two bigger 150/250MVA units and decommissioning existing T5.	2028
Lennox TS	Ten (10) 230kV ABCB & Oil breakers to be replaced by new SF6 breakers.	2026
Cataraqui TS	T1 and T2 230/115kV Autotransformers to be replaced with 150/200/250 MVA units.	2034

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

7.1.1 Cataraqui TS – T1/T2 Autotransformers

The existing T1/T2, 230/115 kV, 150/200/250 MVA autotransformers were built in 1968 and are identified to be replaced based on asset condition assessment. The existing autotransformers have substandard rating due to internal limitations and will be replaced by similar size modern units which is expected to have a higher LTR. This replacement will also help resolve the station capacity need identified in previous cycle RIP and is discussed in section 7.2.4 of this report. The planned in-service date is 2034.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transforming stations in the P to K Region using the summer and winter non-coincidental peak net load forecasts that were provided by the Technical Working Group. Based on the results, the following Station[2] capacity needs have been identified in the during the study period:

7.2.1 Dobbin TS (T3/T4)

Dobbin TS is located near the city of Peterborough, Ontario, and supplies load to Hydro One Distribution through its two 75/100/125MVA, T3/T4 step down transformers. The 2032 non-coincident peak net load is expected to exceed its summer and winter LTRs of 156 MW and 177 MW, respectively.

While the need for additional capacity is projected toward the end of the study period, it depends on several factors, including whether the load increases as anticipated. There is a possibility that this overload could be managed through load transfers to nearby stations. It is recommended that Hydro One Transmission and Distribution collaborate to address this potential issue, and no regional planning coordination is required at this time.

7.2.2 Gardiner TS (T1/T2)

Gardiner TS DESN 1 is located in city of Kingston, Ontario, and is supplied by 230kV, X2H/X4H circuits and supplies load to Hydro One Distribution and Kingston Hydro Corporation (embedded) currently through its two 75/100/125 MVA, T1/T2 step down transformers. These transformers were identified for replacement in previous regional planning cycle and are planned to be replaced in 2027 and will have a better LTR (~170MW). The non-coincident peak net load summer load at this station is exceeding its LTR of 121 MW now.

Kingston Hydro Corporation has projected significant load growth in 2026, driven by an industrial development project, and again in 2032, due to a customer transitioning from a conventional gas heating system to geothermal heating. These new contributions will lead to exceed the new transformer to exceed its LTRs by 2028. It is recommended that a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.3 Napanee TS (T1/T2)

Napanee TS is located in Greater Napanee area, Ontario, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 101.7 MW and 116.9 MW, respectively.

Hydro One Distribution has projected significant load growth in 2026, driven by two large customers. These new loads are expected to exceed the new transformer LTRs by 2026. However, as these load

[2] Belleville TS and Frontenac TS capacity needs were already identified in the 2nd cycle RP and there are no changes to the recommendations made in the RIP by TWG. Updates to all previously identified needs is provided in beginning of section-7 of this report.

forecasts are not committed load, the station capacity need may be shifted accordingly. It is recommended the load growth shall be monitored and a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.4 Cataraqui TS

Cataraqui TS is a 230/115kV autotransformer station that supplies the 115kV stations in the Eastern sub region of the P to k region. It was recommended upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment performed by Hydro One, the conductor in the 115kV yard was found to be sufficient. T1/T2, 230/115 kV, 150/200/250 MVA autotransformers will be replaced with similar size units in 2034. The new autotransformers are expected have higher LTRs and will further address the issue of overload at the station. The replacement of existing autotransformers is based on asset condition assessment and hence it is recommended that no further regional planning coordination is required at this time.

7.2.5 Picton TS

Picton TS is located in Picton area, Ontario, between Bay of Quinte and Prince Edward Bay, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 75 MW and 89 MW, respectively.

The existing T1/T2 transformers have been identified for replacement based on asset condition assessments. The replacement units will be of similar size but will have higher LTRs (~100MW) due to modern designs, which will be enough to supply the load throughout the study period. It is recommended that no further regional planning coordination is required at this time.

7.2.6 Hinchinbrooke DS

Hinchinbrooke DS is located in Central Frontenac area, Ontario and is supplied by 115kV B5QK circuit and supplies Hydro One Distribution Load through its 115/13.2 kV T1 transformer. The 2028 non-coincident peak net load is expected to exceed its winter LTRs of 8.4 MW. The load growth in the area is not significant and can be monitored and addressed within Hydro One Transmission and Distribution. No further regional planning coordination is recommended at this time.

7.2.7 Belleville TS

Belleville TS is located in Belleville area and is supplied by two 230 kV T25B and H23B lines and supplies load to Hydro One Distribution and Elexicon Energy Inc. through its DESN1 two 75/100/125 MVA, 230/44kV, T1/T2 step down transformers. A new Belleville TS DESN2 will be in service by the end of 2026 to address the supply capacity need in the region. Based on the load forecast, and the existing voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency at the Belleville TS, limiting the total loading by the year 2028-2031, depending on the load and LV configuration at Belleville TS DESN2. This undervoltage cannot be mitigated without a partial loss of load at DESN2 post 2028 loading. Therefore, it is recommended to conduct a comprehensive assessment in the next phases of the regional planning cycle to manage this need as well as a full bulk planning study as identified in the previous regional planning cycle.

7.2.8 Frontenac TS

Frontenac TS is located in Kingston area and is supplied by two 115kV B5QK and Q3K lines and supplies Hydro One Distribution, Utilities Kingston, and Eastern Ontario Power Inc. load through its two 50/67/83 MVA, 230/44kV, T3/T4 stepdown transformers. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new station in the area in the near term, which may be built by the Transmitter or the LDC. The Frontenac station capacity need should be further assessed in the next phases of this Regional Planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the P to K Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 115kV B1S

B1S is a long 145km 115kV single-circuit radial line which extends between Barrett Chute GS and Sidney TS and serving Ardoch DS, Northbrook DS and Lodgeroom DS in between. The supply capacity of the line could exceed its continuous rating in in the near to medium timeline following a contingency on Q6S line and high hydro output from generators in the region. The B1S line is limited by a low sag temperature which is the main reason of this line could be overloaded. Hydro One Transmission will perform an internal assessment to see if there is room for improving the sag temperature to address the issue in near time, but it is also recommended to do a full assessment during the next phases of this regional planning cycle.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

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 investments. The TWG determined that the key electric demand driver in the P to K region

to be considered in this sensitivity analysis is the new Industrial load and expansion of urban areas from municipalities, electric vehicle (EV) penetration, and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed the new Industrial load and expansion of urban areas from municipalities, EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer and winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The normal and high growth forecasts are shown in Appendix A.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new station capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Dobbin TS (T3/T4)	2032	2029	2032
2	Gardiner TS (T1/T2)	Current and 2028	Current	Current and 2033
3	Gardiner (T3/T4)	NA	NA	NA
4	Napanee TS (T1/T2)	2026	2026	NA
5	Picton TS	2026	2026	NA
6	Hinchinbrooke DS	2028	2027	NA
7	Sydney TS	NA	2031	NA
8	Otonabee TS 25.6kV	NA	2026	NA
9	Otonabee TS 44kV	NA	2028	NA
10	B1S	2028	2028	2028
11	P4S	NA	2031	NA
12	Belleville TS (undervoltage)	2028	2027	NA
13	Frontenac TS	2027	2026	2030

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 have a summer Long Term Emergency (LTE) rating of about 395 MW. Current normal summer loading forecast for Gardiner TS DESN1 and DESN2 total 293 MW by 2033, leaving about 102 MW of

thermal capacity remaining. If the area experiences a higher load growth as per the scenario above and/or large transmission customer connection up to 100 MWs, there will be capacity need in this area.

The sensitivity analysis identified the additional capacity needs at towards the end of the study period. The sensitivity analysis and these needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Table 7: Needs which do not require further regional coordination

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[3] of the regional planning cycle. A list of these needs are as follows:

Table 8: Needs which require further regional coordination

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028

[3] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] P to K 2nd cycle Regional Infrastructure Plan ("RIP") report (issue May 27, 2022)

[2] P to K 2nd cycle Integrated Regional Resource Plan report (issue November 4, 2021)

[3] Gatineau Corridor End-of-Life Study published in December 2022.

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. October 1, 2024)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: P to K Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Battersea DS	T1/T2	21.9	8.9	9.2	9.1	9.1	9.0	9.1	9.1	9.2	9.2	9.3	9.3
Belleville TS	T1/T2	170.05	164.9	166.6	175.4	183.5	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	55.3	68.0	72.5	77.5	84.1	91.1	101.1
Dobbin DS	T1/T2	16.9	15.9	15.9	15.9	6.2	6.2	6.6	7.0	7.4	7.8	8.2	8.4
Dobbin TS	T3/T4	156.8	70.1	72.7	82.2	111.1	119.9	127.5	133.9	145.9	155.2	159.8	163.9
Frontenac TS	T3/T4	109.3	98.6	102.3	105.2	109.2	113.1	115.8	118.3	123.6	128.2	131.7	135.3
Gardiner TS	T1/T2	121.6	130.3	125.3	128.2	162.6	168.0	170.5	171.9	175.8	177.7	195.4	200.8
Gardiner TS	T3/T4	111.2	46.8	57.1	57.4	57.7	57.9	79.9	84.9	86.6	88.4	90.3	92.3
Harrowsmith DS	T1/T2	21.9	15.8	15.7	15.5	15.6	15.5	15.6	15.7	15.7	15.8	15.9	16.1
Havelock TS	T1/T2	86.4	63.1	62.5	65.2	64.8	64.5	65.0	65.1	65.6	66.0	66.3	66.7
Hinchinbrooke DS	T1	6.8	6.1	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.5	6.5
Lodgeroom DS	T1/T2	21.9	8.6	8.5	8.6	8.6	8.6	8.6	8.5	8.6	8.5	8.6	8.6
Napanee TS	T1/T2	101.7	66.6	75.2	82.4	108.4	110.9	105.2	108.3	111.6	113.0	114.3	118.2
Northbrook DS	T1	8.4	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	6.0	6.0
Otonabee TS 27.6kV	T1/T2	92.52	81.7	82.6	83.9	74.5	75.3	75.7	76.0	76.4	76.9	77.5	78.2
Otonabee TS 44kV	T1/T2	97.2	81.2	82.0	77.3	79.3	82.3	85.0	85.7	88.3	89.7	90.9	91.6
Picton TS	T1/T2	75.6	64.3	69.7	71.8	79.2	85.7	88.4	90.8	93.1	95.6	97.5	99.4
Sharbot DS	T1	6.2	3.9	4.0	4.0	4.0	3.9	4.0	4.0	4.0	4.0	4.0	4.1
Sidney TS	T1/T2	111.8	80.6	83.0	88.4	95.8	96.2	100.2	100.3	100.7	102.6	103.2	103.9
Port Hope TS	T1/T2	122.6	52.0	54.2	58.3	59.6	60.3	61.1	61.5	65.2	72.2	73.0	73.9

Port Hope TS	T3/T4	101.7	73.4	73.7	74.5	74.7	74.8	74.9	74.9	75.0	75.3	75.7	76.3
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.2: P to K Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5
Battersea DS	T1/T2	24.3	11.9	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.6
Belleville TS	T1/T2	183.4	158.5	159.9	172.9	184.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4	0.0	0.0	0.0	0.0	59.2	75.6	82.2	90.0	98.2	107.3	119.6
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.4	10.5	11.6	12.6	13.7	14.7	15.8	16.3
Dobbin TS	T3/T4	177.7	80.2	83.5	93.5	105.6	117.5	127.8	136.3	164.7	177.0	183.0	188.4
Frontenac TS	T3/T4	123.5	101.8	110.0	112.7	116.3	120.0	122.6	124.7	129.4	132.2	135.2	138.3
Gardiner TS	T1/T2	143.5	128.4	123.4	126.5	159.8	165.3	168.1	169.4	173.2	175.1	192.0	197.4
Gardiner TS	T3/T4	138.7	41.5	51.7	52.1	52.6	80.0	85.8	87.5	89.4	91.3	93.3	95.5
Harrowsmith DS	T1/T2	24.3	19.7	20.2	20.5	20.7	20.9	21.1	21.2	21.4	21.5	21.7	21.9
Havelock TS	T1/T2	97.2	78.2	80.5	81.5	82.7	83.5	84.3	84.7	85.3	87.5	88.3	89.2
Hinchinbrooke DS	T1	8.6	8.2	8.4	8.5	8.6	8.7	8.7	8.8	8.9	8.9	9.0	9.1
Lodgeroom DS	T1/T2	24.3	11.1	11.4	11.5	11.7	11.8	12.0	12.0	12.1	12.4	12.5	12.7
Napanee TS	T1/T2	116.9	81.0	89.0	95.9	120.2	122.7	117.8	120.7	121.9	123.2	124.4	125.7
Northbrook DS	T1	10.8	8.7	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.5	9.6	9.8
Otonabee TS 27.6kV	T1/T2	109.8	54.9	55.8	57.1	58.1	58.9	59.3	59.5	59.7	60.0	60.3	60.8
Otonabee TS 44kV	T1/T2	109.8	77.8	78.8	74.0	76.1	79.2	81.9	82.6	85.1	94.3	95.3	96.0
Picton TS	T1/T2	89.1	60.9	68.6	70.8	78.3	85.0	87.8	90.2	92.5	94.9	96.6	98.6

Sharbot DS	T1	8.4	5.4	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1
Sidney TS	T1/T2	111.8	77.1	76.6	82.4	96.8	97.2	102.4	103.1	104.5	107.3	108.4	109.6
Port Hope TS	T1/T2	139.7	61.3	63.4	67.4	68.7	69.6	70.6	71.0	74.5	81.0	81.8	82.7
Port Hope TS	T3/T4	115.9	75.6	76.1	77.1	77.6	77.9	78.3	78.3	78.5	78.9	79.3	79.9
CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Table A.3: P to K Region Summer Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	3.0
Battersea DS	T1/T2	21.9	8.9	9.4	9.5	9.6	9.7	9.7	9.7	9.8	9.9	10.0	10.1
Belleville TS	T1/T2	170.05	164.9	167.4	180.7	192.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	70.4	89.5	96.3	103.8	113.7	124.2	139.2
Dobbin DS	T1/T2	16.9	15.9	15.9	16.0	6.0	6.0	6.6	7.2	7.8	8.4	9.1	9.3
Dobbin TS	T3/T4	156.8	70.1	73.9	88.2	131.6	144.8	156.1	165.8	183.8	197.8	204.7	210.7
Frontenac TS	T3/T4	109.3	98.6	104.2	108.5	114.5	120.3	124.4	128.2	136.1	143.0	148.2	153.6
Gardiner TS	T1/T2	121.6	130.3	137.7	142.1	193.7	201.7	205.5	207.6	213.4	216.3	242.9	251.0
Gardiner TS	T3/T4	111.2	46.8	62.2	62.6	63.1	63.4	96.4	103.9	106.4	109.1	112.0	115.0
Harrowsmith DS	T1/T2	21.9	15.8	16.0	16.3	16.5	16.7	16.8	16.9	16.9	17.1	17.4	17.6
Havelock TS	T1/T2	86.4	63.1	63.8	67.9	68.4	69.0	69.8	69.9	70.6	71.2	71.7	72.2
Hinchinbrooke DS	T1	6.8	6.1	6.7	6.7	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1
Lodgeroom DS	T1/T2	21.9	8.6	8.7	8.7	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.2
Napanee TS	T1/T2	101.7	66.6	79.5	90.3	129.4	133.0	141.5	146.1	151.1	153.1	155.1	161.0
Northbrook DS	T1	8.4	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
Otonabee TS 27.6kV	T1/T2	92.52	81.7	83.0	85.0	99.0	100.2	100.8	101.3	101.8	102.6	103.5	104.5
Otonabee TS 44kV	T1/T2	97.2	81.2	82.4	89.6	92.7	97.2	101.2	102.3	106.1	108.3	110.0	111.1
Picton TS	T1/T2	75.6	64.3	72.4	75.5	86.6	96.5	100.4	104.1	107.5	111.2	114.1	117.0
Sharbot DS	T1	6.2	3.9	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.4
Sidney TS	T1/T2	111.8	80.6	84.1	92.3	103.4	104.0	109.9	110.1	110.7	113.5	114.5	115.6
Port Hope TS	T1/T2	122.6	52.0	55.3	61.5	63.3	64.4	65.6	66.2	71.7	82.3	83.5	84.9
Port Hope TS	T3/T4	101.7	73.4	73.8	75.1	75.4	75.5	75.7	75.7	75.9	76.3	76.9	77.7
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9

CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.4: P to K Region – Winter Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Battersea DS	T1/T2	24.3	11.9	12.3	12.4	12.5	12.6	12.6	12.6	12.7	12.7	12.8	12.9
Belleville TS	T1/T2	183.4	158.5	160.6	180.2	196.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4		0.0	0.0	0.0	79.6	104.1	114.0	125.8	138.1	151.6	170.1
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.5	10.5	12.2	13.7	15.3	16.9	18.6	19.2
Dobbin TS	T3/T4	177.7	80.2	85.2	100.2	118.2	136.1	151.5	164.3	206.9	225.4	234.4	242.4
Frontenac TS	T3/T4	123.5	101.8	114.0	118.1	123.6	129.0	133.0	136.2	143.2	147.4	151.8	156.6
Gardiner TS	T1/T2	143.5	128.4	135.9	140.5	190.4	198.7	202.9	204.9	210.6	213.4	238.8	246.9
Gardiner TS	T3/T4	138.7	41.5	56.8	57.4	58.1	99.2	107.9	110.5	113.3	116.2	119.3	122.5
Harrowsmith DS	T1/T2	24.3	19.7	20.5	20.9	21.2	21.5	21.8	22.0	22.2	22.4	22.7	23.0
Havelock TS	T1/T2	97.2	78.2	81.7	83.2	84.9	86.1	87.4	88.0	88.8	92.1	93.3	94.7
Hinchinbrooke DS	T1	8.6	8.2	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5
Lodgeroom DS	T1/T2	24.3	11.1	11.6	11.8	12.0	12.2	12.4	12.5	12.7	13.0	13.2	13.5
Napanee TS	T1/T2	116.9	81.0	93.0	103.3	139.8	143.6	150.9	155.3	157.0	159.0	160.7	162.8
Northbrook DS	T1	10.8	8.7	9.0	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1	10.3
Otonabee TS 27.6kV	T1/T2	109.8	54.9	56.3	58.2	59.8	61.0	61.5	61.8	62.1	62.5	63.1	63.8
Otonabee TS 44kV	T1/T2	109.8	77.8	79.3	86.5	89.7	94.2	98.4	99.5	103.2	116.9	118.5	119.6
Picton TS	T1/T2	89.1	60.9	72.5	75.8	87.0	97.0	101.2	104.8	108.3	111.9	114.5	117.4
Sharbot DS	T1	8.4	5.4	5.7	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4
Sidney TS	T1/T2	111.8	77.1	77.8	86.5	108.1	108.6	116.5	117.5	119.6	123.8	125.5	127.2
Port Hope TS	T1/T2	139.7	61.3	64.5	70.4	72.5	73.8	75.2	75.8	81.0	90.8	92.0	93.4
Port Hope TS	T3/T4	115.9	75.6	76.3	77.9	78.6	79.0	79.6	79.7	80.0	80.5	81.2	82.1

CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Ardoch DS (T1)	115	B1S
2	Battersea DS (T1/T2)	115	S1K
3	Belleville TS (T1/T2)	230	T25B, H23B
4	Dobbin DS (T1/T2)	115	P3S, P4S
5	Dobbin TS (T3/T4)	115	Q20H, Q20A
6	Frontenac TS (T3/T4)	115	B5QK, Q3K
7	Gardiner TS (T1/T2)	230	X4H, X2H
8	Gardiner TS (T3/T4)	230	X2H, X4H
9	Harrowsmith DS (T1/T2)	115	B5QK
10	Havelock TS T1/T2	115	T31H, H27H
11	Hinchinbrooke DS (T1)	115	B5QK
12	Lodgeroom DS (T1/T2)	115	B1S
13	Napanee TS (T1)	230	X21, X22
14	Northbrook DS (T1)	115	B1S
15	Otonabee TS (T1/T2) 27.6	230	T22C, T31H
16	Otonabee TS (T1/T2) 44	230	T22C, T31H
17	Picton TS (T1/T2)	230	X21, X22
18	Sharbot DS (T1)	115	B5QK
19	Sidney TS (T1/T2)	115	Q12AT, Q6S
20	Port Hope TS (T1/T2)	115	P3S, P4S
21	Port Hope TS (T3/T4)	115	P3S, P4S

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
2	Picton TS – Lennox TS	X21, X22	230
3	Belleville TS – Hinchinbrooke SS	H23B	230
4	Hinchinbrooke SS – Havelock TS	H27H	230
5	Dobbin TS – Chenaux TS	X1P	230
6	Dobbin TS – Chat Falls GS	C27P	230
7	Clarington TS – Havelock TS	T32H	230
8	Chat Falls GS – Havelock TS	C25H	230
9	Clarington TS – Chat Falls GS	T22C	230

10	Cherrywood TS – Dobbin TS	P15C	230
11	Clarington TS – Belleville TS	T25B	230
12	Dobbin TS – Sidney TS	P3S, P4S	115
13	Cataraqui TS – Sidney TS	Q6S	115
14	Barrett Chute TS – Sidney TS	B1S	115
15	Cataraqui TS – Frontenac TS	Q3K	115
16	Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Elexicon Energy Inc.
3	Kingston Hydro Corporation
4	Lakefront Utilities Inc.
5	Eastern Ontario Power Inc.

Appendix E: List of Municipalities in the P to K Region

No.	Name of Municipality
1	Municipality of Clarington
2	City of Kingston
3	County of Frontenac
4	Township of North Frontenac
5	Township of South Frontenac
6	Township of Central Frontenac
7	Township of Frontenac Islands
8	City of Belleville
9	City of Quinte West
10	Municipality of Centre Hastings
11	Municipality of Hastings Highlands
12	Municipality of Marmora and Lake
13	Municipality of Tweed
14	Town of Bancroft
15	Town of Deseronto
16	Township of Carlow/Mayo
17	Township of Faraday
18	Township of Limerick
19	Township of Madoc
20	Township of Stirling-Rawdon
21	Township of Tudor & Cashel
22	Township of Tyendinaga
23	Township of Wollaston
24	Municipality of Brighton
25	Town of Cobourg
26	Municipality of Port Hope
27	Municipality of Trent Hills
28	Township of Alnwick/Haldimand
29	Township of Cramahe
30	Township of Hamilton
31	City of Peterborough
32	Township of Asphodel-Norwood
33	Township of Cavan Monaghan
34	Township of Douro-Dummer
35	Township of Havelock-Belmont-Methuen
36	Township of North Kawartha
37	Township of Otonabee-South Monaghan
38	Township of Selwyn

39	Municipality of Trent Lakes
40	Prince Edward
41	Town of Greater Napanee
42	Township of Addington Highlands
43	Township of Loyalist
44	Township of Stone Mills

Appendix F: 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
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
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
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX H PETERBOROUGH TO KINGSTON – SCOPING ASSESSMENT



Peterborough to Kingston

Scoping Assessment Outcome Report

April 28, 2025

ieso
Connecting Today.
Powering Tomorrow.

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1. Introduction

This Scoping Assessment Outcome Report is produced as part of the Ontario Energy Board's ("OEB" or "Board") regional planning process and sets out the planning approach to address electricity needs that have been identified in the Peterborough to Kingston region. This is the third cycle of planning for the region, and the process was initiated in September 2024. The Needs Assessment ("NA") is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. ("Hydro One"), and the Technical Working Group (TWG) consisting of Hydro One, the Independent Electricity System Operator (IESO) and the Local Distribution Companies. The Needs Assessment Report was finalized and published on December 20, 2024, and identified a list of needs that either require further regional coordination or can be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

During the Scoping Assessment, TWG reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach, as well as geographically grouping the needs where beneficial to efficiently carry out the study. The planning approaches considered include:

- **An Integrated Regional Resource Plan ("IRRP") –** through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required.
- **A Regional Infrastructure Plan ("RIP")** led by the transmitter – which considers more straight-forward wires only option with limited engagement; or
- **A local plan** undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is required.

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)
- 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 and/or wires planning, if required
- Establishes the composition of the Technical Working Group, if required

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")
- Hydro One Networks Inc. ("Hydro One Distribution")
- Elexicon Energy Inc.
- Lakefront Utilities Inc
- Eastern Ontario Power Inc.
- Utilities Kingston

3. Overview of Region and Background

3.1 Overview of the Peterborough to Kingston Region

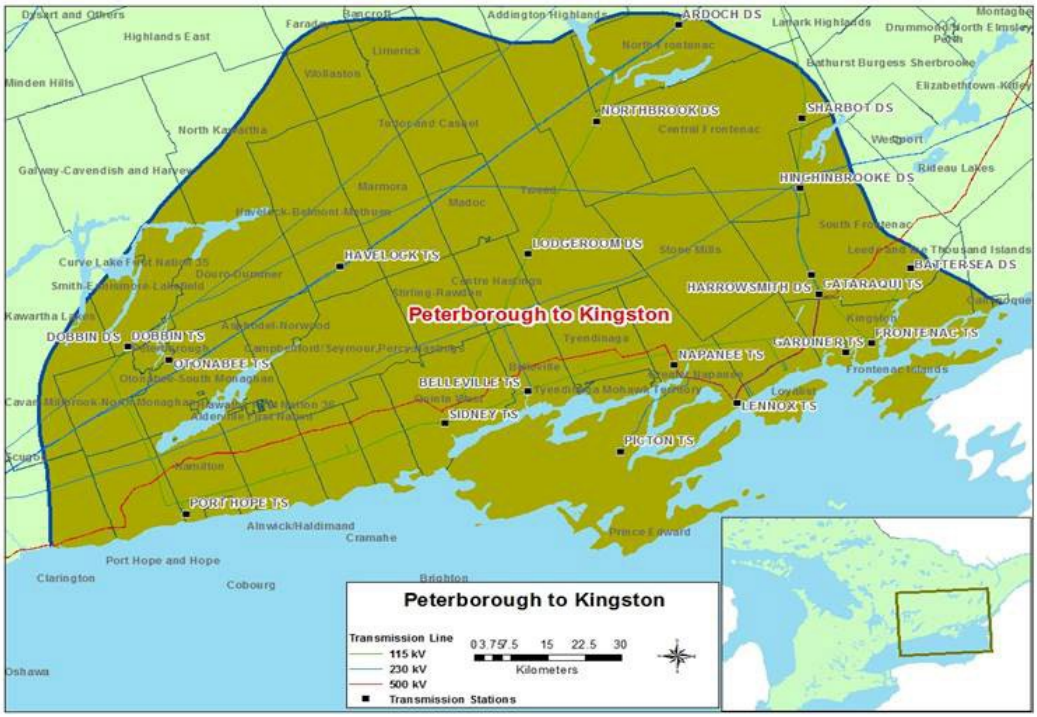
The Peterborough-Kingston region is located in eastern Ontario and is composed of the following: Municipality of Clarington located in the Regional Municipality of Durham, the City of Kingston, the County of Frontenac consisting of the Townships of North Frontenac, South Frontenac, Central Frontenac, and Frontenac Islands, The City of Belleville, City of Quinte West, Prince Edward County, the County of Hastings including the Municipalities of Centre Hastings, Hastings Highlands, Marmora and Lake, Tweed, the, Carlow/Mayo, Faraday, Limerick, Madoc, Stirling-Rawdon, Tudor & Cashel, Tyendinaga, Wollaston, and the Towns of Bancroft and Deseronto, the County of Northumberland consisting of the Municipalities of Brighton, Port Hope, Trent Hills, the Town of Cobourg, and the Townships of Alnwick/Haldimand, Cramahe, and Hamilton, the City of Peterborough and the County of Peterborough including the Townships of Asphodel-Norwood, Cavan Monaghan, and the Townships of Douro-Dummer, Havelock-Belmont-Methuen, North Kawartha, Otonabee-South Monaghan, Selwyn, and the Municipality of Trent Lakes, the County of Lennox and Addington including the Town of Greater Napanee, and the Townships of Addington Highlands, Loyalist, and Stone Mill.

Within the region, Peterborough and Kingston are the two largest population centres. The region also comprises several Indigenous communities including Alderville First Nation, Algonquins of Ontario, Algonquins of Pikwakanagan, Chippewas of Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, Mohawks of the Bay of Quinte, Kawartha Nishnawbe, Métis Nation of Ontario.

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries. The electricity infrastructure supplying the Peterborough-Kingston region is shown in

Figure **1**. Hydro One owns the transmission assets in this region.

Figure 1| Overview of the Peterborough to Kingston region



The region is supplied by four local distribution companies (LDC). Eastern Ontario Power serves over 3,500 distribution customers in Gananoque, Ontario. Lakefront Utilities serves 10,000 distribution customers across the Town of Cobourg and the Village of Colborne. Utilities Kingston serves 28,000 distribution customers in Central Kingston. Hydro One Distribution supplies distribution customers in the surrounding areas of the region. These four LDCs receive power at the step-down transformer stations and distribute it to end users, i.e., industrial, commercial and residential customers.

Electrical supply to the Peterborough-Kingston region is provided through a network of 230 kilovolt (kV) and 115 kV circuits supplied by two 500/230 kV transformers at Lennox Transformer Station (TS), and four 230/115 kV transformers: two at Cataraqui TS and two at Dobbin TS. There are 10 step-down transformer stations in the area: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight Distribution Stations (DS) in the region: Dobbin DS, Ardoch DS, Northbook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS. Finally, there are five Customer Transformer Stations (CTS) in the region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Shannonville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

There are two major thermal generating stations located in the region, injecting at the 500 kV and 230 kV voltage levels: Lennox GS (~2,150 MW) and Napanee GS (~1,000 MW). In addition, there are over 400 MW of transmission-connected wind and solar generation facilities across the region. The 115 kV system between Dobbin TS and Frontenac TS is also connected via long 115 kV circuits to Barrett Chute GS located outside the region on the Madawaska River. Finally, there is a total of 189 MW of distribution-connected generation spread across the region.

As per Hydro One's Needs Assessment, this area has net extreme weather winter peak demand of approximately 1,249 MW, which occurred in the year 2024. This area is expected to grow to approximately 1,768 MW by the year 2033. Furthermore, the net extreme weather summer peak

demand was approximately 1,211 MW in the year 2024. This is expected to grow to approximately 1,642 MW by the year 2028. This corresponds to a growth rate of 4.6 percent per year in the winter and 4 percent in the summer.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for Peterborough to Kingston was completed in February 2015 with the Needs Assessment concluding that there was no need at that time for further integrated planning for the region and that localized wires-only plans be developed for the needs identified.

The second cycle of was completed in 2021; during this regional planning process the TWG decided an IRRP was required for the region as several near-, mid- and long-term needs were identified and a range of options (including non-wire alternatives) had to be evaluated as part of the solution. As a result of the recommendations made within the second cycle, projects are currently in-progress to address these needs.

Table 1 lists the projects that have been completed since the region's second cycle.

Table 1| List of completed projects

Project	Completion Date
Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2	2024
Belleville TS (Asset Renewal) – T1/T2 transformers were replaced by similar 75/100/125 MVA standard step-down transformers	2021/2022

Table 2 covers projects that are currently underway since the region's second cycle RIP.

Table 2| List of projects currently underway

Project	Expected Completion Date
Otonabee TS 44kV (Station Capacity) – 8 MW load transfer to Dobbin TS	2025
Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site	2026
Gardiner TS DESN 1 (Asset Renewal) – T1/T2 to be replaced with two 75/100/125 MVA transformers	2026/2027
Durham-Kawartha Power Line (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One has initiated building a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022	2029
Dobbin TS (Asset Renewal/Decommissioning) – Autotransformers T1 and T2 are expected to be replaced with two 150/250MVA along with the decommissioning of T5.	2028
Kingston MTS (Station Capacity) New 230kV DESN with two 75/100/125MVA transformer expected to serve load growth in Central Kingston.	2030
Port Hope TS (Asset Renewal) – Transformers T3/T4 to be replaced like for like with two 50/67/83 MVA units.	2033

During this regional planning cycle, the TWG will monitor and review the status of ongoing projects, specifically assessing the progress of previous recommendations and impact of asset renewals on system limits.

3.3 Needs Identified in the 2024 Needs Assessment

For this third cycle of regional planning, the NA identified several needs in the Peterborough-Kingston region based on a 10-year demand forecast and their most up-to-date asset sustainment plans. Additionally, the regional working group participants have considered the characteristics of the transmission and distribution systems in the region, the potential for regional coordination, and the opportunities for stakeholder and community engagement, to develop the following regional needs.

3.3.1 Station Capacity Needs

Station capacity refers to a stations ability to convert and deliver power from the transmission system to an LDC's distribution system. The NA identified several stations expected to exceed their current capacity as described in Table 3.

Table 3| Station capacity needs based on normal growth scenario

Station	Need Year
Gardiner TS (T1/T2)	Current*/2028
Napanee TS (T1/T2)	2026
Picton TS	2026
Hinchinbrooke DS	2028
Dobbin TS (T3/T4)	2032
Frontenac TS	2027

*Gardiner TS is projected to exceed its station capacity today; planned transformer replacements are expected to mitigate the station overload. Based on the NA load forecast, the new transformers will exceed station capacity in 2028.

When the high growth forecast is considered, there are additional station capacity needs at Otonabee TS and Sidney TS in the year 2026 and 2031, respectively.

3.3.2 Load Security and Restoration Needs

Load security criteria places limits on the total amount of load interrupted following major transmission outages. Load restoration criteria describe timeframes by which power must be restored to loads interrupted due to a major transmission outage. No load security or restoration needs were identified as part of this cycle's NA.

3.3.3 Supply Capacity Needs

Supply capacity needs identify the transmission system's ability to supply power through the transmission lines and auto-transformers to local distribution systems being serviced within the region. The NA identified several supply capacity needs, as summarized in **Table 4**.

Table 4| Supply Capacity Needs

Need	Need Description
Belleville TS	Transmission voltage issues under contingency, currently evaluated under Eastern Ontario Bulk Planning Study.
B1S (Q6S Out)	B1S is expected to exceed its thermal limits when Q6S is out of service during high hydro generators output.
Cataraqui TS	Review supply/station capacity in this IRRP.
X2H	Potential supply capacity need with Kingston MTS and a large transmission customer connection.
X4H	Potential supply capacity need with Kingston MTS and a large transmission customer connection.
B5QK	Re-evaluate supply capacity need in this IRRP.
Q3K	Potential supply capacity need under high growth or large transmission customer connection.

During the high growth forecast, an additional supply capacity needs exists on circuit P4S in the year 2031.

For the Cataraqui TS, it was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this regional planning cycle.

In the second regional planning cycle, there was a long-term need identified for the circuit B5QK (in the year 2038). As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20-year load forecast will be developed. Given the potential of a large customer connection in Central Kingston, the supply capacity of both Q3K and B5QK will be reviewed.

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 are expected to approach their summer Long Term Emergency (LTE). Given the Kingston MTS project that is underway and the potential of a large transmission customer connection, there will be a potential supply capacity need.

3.3.4 End-of-life Asset Replacement Needs

When assets are determined to be approaching end-of-life, an assessment needs to be performed on whether the asset should be replaced, refurbished, upgraded, retired, or another solution be developed. The NA newly identified asset renewal needs, as shown in **Table 5**.

Table 5| Stations with asset renewal needs

Station	End of Life Year	Description
Cataraqui TS	2034	T1/T2 expected to be replaced 2034
Gardiner TS	2027	Transformers at DESN1 expected to be replaced 2026-2027.
Port Hope TS	2033	T3/T4 planned to be replaced 2033
Dobbin TS	2028	Replacement of T1/T2 and decommissioning T5 for 2028.
Lennox TS	2026	Ten 230 kV ABCB & Oil breakers to be replaced by new SF6 breakers.
Picton TS	2026	T1/T2 planned to be replaced 2026

3.3.5 Analysis of Needs and Planning Approach

The regional participants have discussed the needs in the Peterborough-Kingston region. They considered several factors before determining the recommended planning approach, including the potential for regional coordination and for a wide range of solutions - including conservation, generation, and new technologies, wires infrastructure and non-wires solutions.

Needs identified through the NA were reviewed during the Scoping Assessment to determine whether a Local Plan, Regional Infrastructure Plan, or Integrated Regional Resource Plan regional planning approach is most appropriate.

An Integrated Regional Resource Plan is recommended for the Peterborough to Kingston region. The following sections outline the summary of needs that will be reviewed in the IRRP.

3.3.6 Summary of Needs to be Reviewed in the IRRP

Identified needs that will be reviewed in the IRRP are summarized in Table 6; their locations are shown in Figure 2.

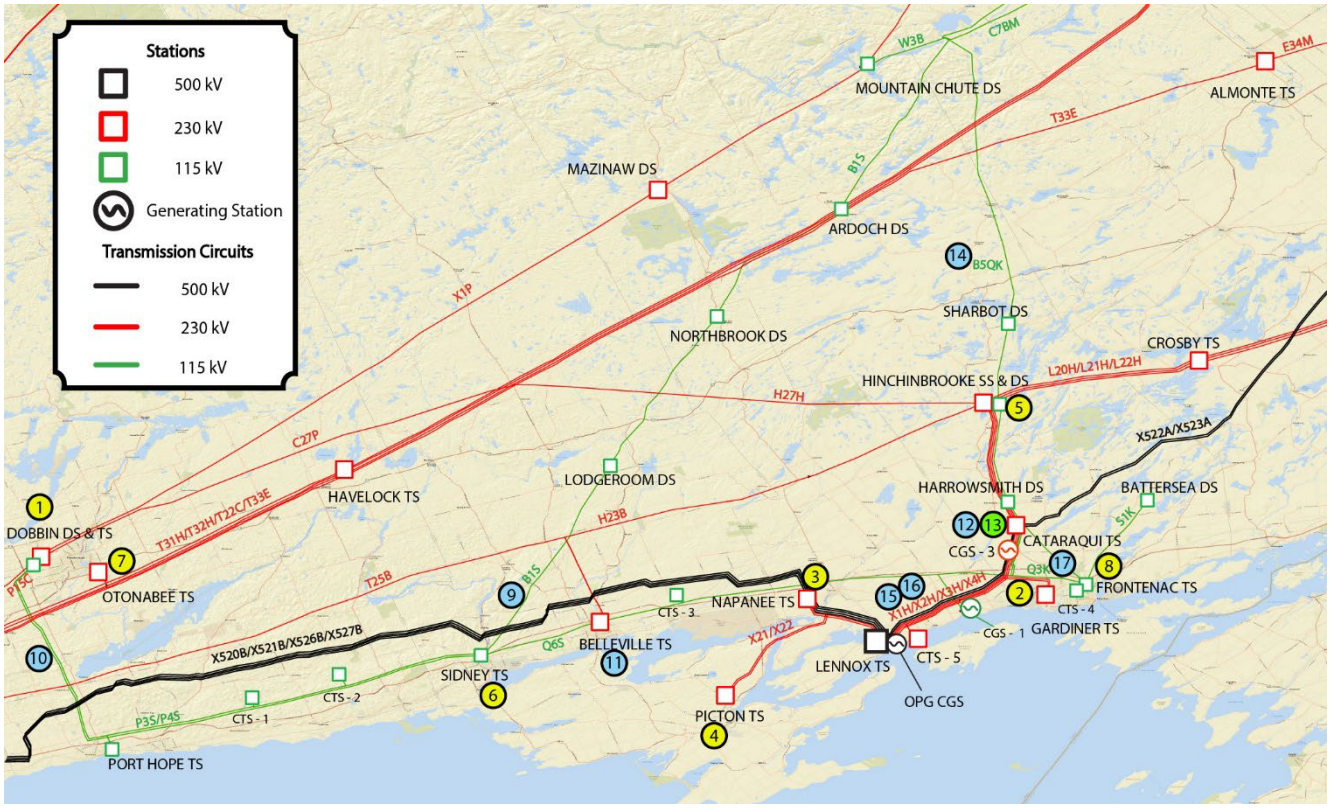
Table 6| Summary of the needs to be reviewed in the IRRP

#	Need	Need Type	Estimated Timing in N/A	Need Description
1	Dobbin TS (T3/T4)	Station Capacity	2032	Station Overload
2	Gardiner TS (T1/T2)	Station Capacity	Current/2028	Transformers are planned to be replaced but based on the needs assessment forecast, there is an overload in 2028.
3	Napanee TS (T1/T2)	Station Capacity	2026	Station Overload
4	Picton TS	Station Capacity	2026	Station Overload, transformers are expected to be replaced and could meet forecasted load.
5	Hinchinbrooke DS	Station Capacity	2028	Station Overload
6	Sidney TS*	Station Capacity	2031	Station Overload
7	Otonabee TS*	Station Capacity	2026	Station Overload
8	Frontenac TS	Station Capacity	2027	Station Overload
9	B1S (Q6S Out)	Supply Capacity	-	During high demand, the transmission line is expected to exceed its thermal limits when Q6S is out of service.
10	P4S*	Supply Capacity	-	Review the need with TWG during IRRP.
11	Belleville TS	Supply Capacity	-	Transmission voltage issues, currently being evaluated under Eastern Ontario Bulk Planning Study, including the timing of the need.
12	Cataraqui TS	Supply Capacity	-	Review the need with TWG during IRRP.
13	B5QK	Supply Capacity		Review the need with TWG during IRRP.
14	X2H	Supply Capacity	-	Potential supply capacity need with the connection of Kingston MTS and a large transmission customer.
15	X4H	Supply Capacity	-	Potential supply capacity need with the connection of Kingston MTS and a large transmission customer.

16	Q3K	Supply Capacity		Potential supply capacity need under high growth or large transmission customer connection.
17	Cataraqui TS	End-of-life Asset Replacement	2034	T1/T2 expected to be replaced 2034

*When high growth forecast is considered, there are station capacity needs at Otonabee TS and Sidney TS in the year 2026 and 2031 as well as supply capacity needs on circuit P4S in the year 2031.

Figure 2 | Geographic location of needs to be reviewed in the IRRP



4. Conclusion and Next Steps

This Scoping Assessment concludes that:

- Based on the available information, an IRRP will be undertaken for the Peterborough to Kingston region;
- The number and potential linkages between the station capacity, supply capacity, and end-of-life requirements as stated in the summary **Table 6** above require an IRRP;
- The recommendations from the previous planning cycle should be assessed and evaluated;
- The composition of the IRRP Working Group will include the IESO, Hydro One Transmission, Hydro One Distribution, Elexicon Energy Inc., Lakefront Utilities Inc., Eastern Ontario Power Inc., Kingston Hydro.
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required; and
- The Peterborough to Kingston IRRP will co-ordinate its findings with the East Bulk Study, and vice-versa.

All IRRPs 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 any 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 Terms of Reference for the Peterborough-Kingston IRRP are attached in Appendix B.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CGS	Customer Generating Station
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distribution Station
FIT	Feed-in-Tariff
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
MTS	Municipal Transformer Station
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station

Appendix 2 – Terms of Reference

1. Introduction and Background

Peterborough to Kingston is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) formalized Regional Planning Process. These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for Peterborough to Kingston Integrated Regional Resource Plan ("IRRP").

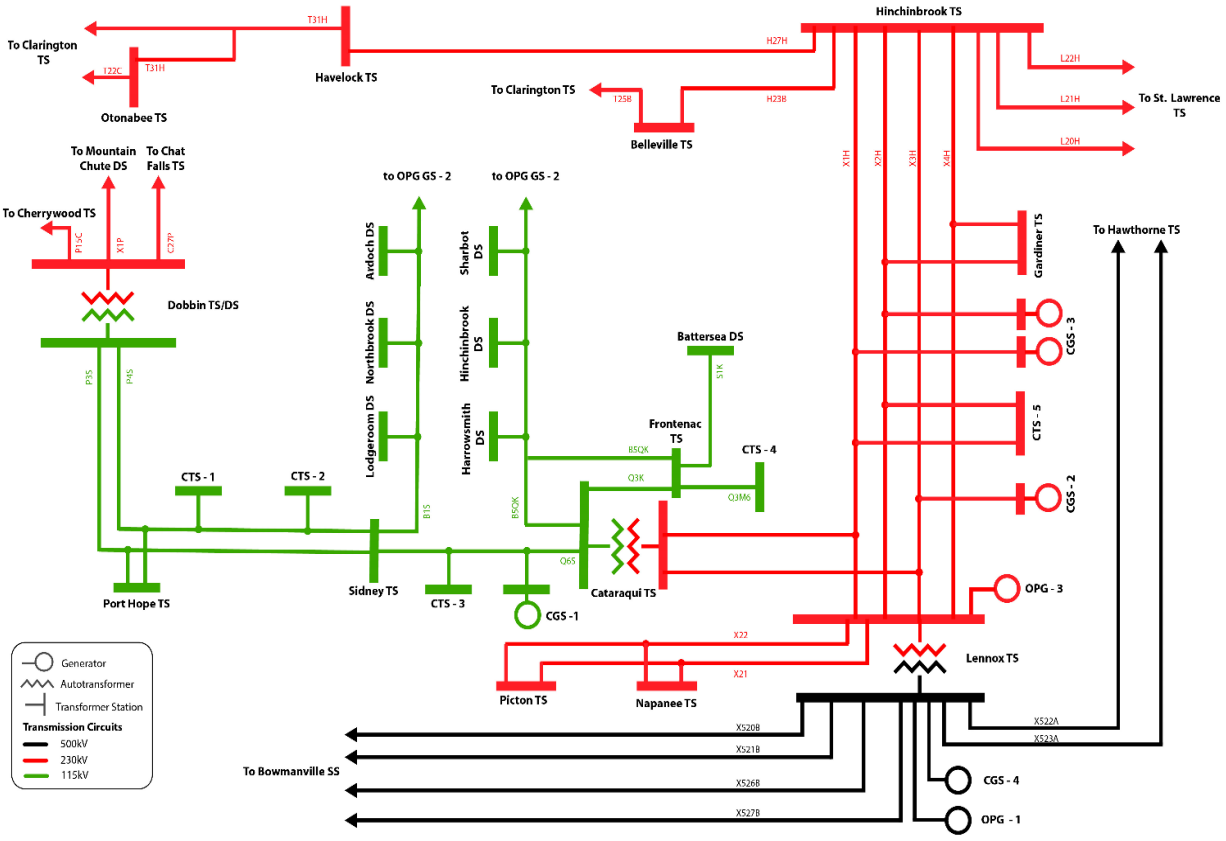
2. Electrical System of the Peterborough to Kingston area

Electrical supply to the Peterborough to Kingston Region ("Region") is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3. The 500 kV system is part of the bulk power system and is not studied as part of this IRRP:

- Lennox TS is the major transmission station that connects the 500 kV network to the 230 kV system via two 500/230 kV autotransformers.
- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230 kV network to the 115 kV system via 230/115 kV autotransformers.
- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS.
- There are also eight Distribution Stations that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS.
- Five Customer Transformer Stations (CTS) are supplied in the Region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.
- There are 7 existing transmission connected generating stations in the Region as follows:
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS
    - Napanee GS is a 910 MW gas-fired plant connected to Lennox TS to the 500 kV system.
    - Kingston Solar CGS is a 100 MW solar generation facility connected to 230 kV circuit X2H
    - Stone Mills CGS is a 60 MW solar generation facility connected to 230 kV circuit H23B
    - Amherst Island CGS is a 76 MW wind farm connected to 115 kV circuit Q6S

Figure 3 | Single line diagram of Peterborough to Kingston Region



3. Objectives

The Peterborough to Kingston Area IRRP will assess the adequacy of electricity supply to customers in the Region and will develop a set of recommended actions to maintain reliability of supply to the Region over the next 20 years (2025-2045). Specifically, this IRRP will:

- Assess the adequacy of electricity supply to customers in the Peterborough to Kingston Region over the next 20 years;
- Determine whether a need exists to initiate development work or fully commit infrastructure investments (wires or non-wires) in this planning cycle;
- Assess potential risks & uncertainties over the longer term and identify near-term actions to manage/mitigate these risks, where applicable;
- Develop an implementation plan that maintains flexibility to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs; and
- Inform Local Distribution Companies' ("LDC") OEB rate filings.

4. Scope

This IRRP, developed with the Technical Working Group ("TWG"), will consist of an integrated plan to meet the needs of the region. The plan will assess all capacity, restoration and sustainment needs in the area and incorporate input from community engagement activities.

The IRRP process will consist of the following activities:

- Develop an updated 20-year demand forecast for the region.
- Evaluate previously identified needs and identify any new needs.
- Perform an assessment of options that meet each need identified. Options are evaluated using criteria including, but not limited to, technical feasibility, economics, reliability performance, environmental and social factors. The options analysis will be divided into groupings based on the priority/timing of the needs, any known lead time information, and the depth of analysis required.
- Development of the recommendations and implementation plan.

Publication of the IRRP report documenting the assessment, including the near, mid, and long-term needs, recommendations and implementation plan.

5. Data and Assumptions

The plan will consider the following data and assumptions, as applicable:

Demand forecast

- Historical peak demand in the region and historical weather correction for median and extreme conditions. The region's coincident demand and station level non-coincident demand will be forecasted to identify both the location and timing of reliability issues.
- Potential future load customers
- Gross peak demand forecast scenarios by station under normal growth and as needed, high and low growth.
- Peak demand forecast for transmission-connected customers

Conservation and Demand Management (CDM)

- LDC CDM plans
- Verified LDC results and progression towards OEB conservation targets, and any other CDM programs/opportunities in the area
- LDC customers' conservation forecasts
- Conservation potential studies, if available
- Load segmentation data for each TS based on customer type (residential, commercial, industrial)

Local supply resources

- Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
- Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
- Future district energy plans, combined heat and power, energy storage, or other generation proposals

Relevant local plans

- LDC Distribution System Plans
- Community Energy Plans and Municipal Energy Plans
- Municipal Growth Plans
- Any transit plans impacting electricity use

Criteria, codes and other requirements

- Ontario Resource and Transmission Assessment Criteria ("ORTAC")
    - Supply capability
    - Load security
    - Load restoration requirements
- NERC and NPCC reliability criteria, as applicable

    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
- Other applicable requirements

Existing system capability

- Transmission line ratings as per transmitter records
- Transformer ratings (10-day LTR) as per asset owner records
- Load transfer capability for restoration during transmission system outages and/or for transmission level capacity needs
- Technical and operating characteristics of local generation

End-of-life asset considerations/sustainment plans & end of expected service life information

- Transmission assets
- Distribution assets

Other considerations, as applicable.

6. Technical Working Group ("TWG")

The following are the LDCs in the region:

- Elexicon Energy Inc.
- Utilities Kingston
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.
- Hydro One Networks Inc. (Distribution)

The TWG consists of the LDC stated above as well as the Independent Electricity System Operator ("IESO") and Hydro One Networks Inc. (Transmission).

Authority and Findings

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to them 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 TWG is committed to conducting plan-level engagement throughout the development of the Peterborough-Kingston IRRP.

Engagement will consist of meetings with municipalities and Indigenous communities within the region, Indigenous communities who may have an interest in the region and the Métis Nation of Ontario to discuss regional planning, the development of the Peterborough-Kingston IRRP, and integrated solutions.

Engagement will continue throughout the development and completion of the IRRP.

8. Activities, Timeline and Primary Accountability

Table A-1 | Summary of IRRP timelines and activities

	Activity	Lead Responsibility	Deliverable(s)	Start – End Date
1	**Commence IRRP Process** - Prepare terms of reference considering stakeholder input - Kick-off meeting with working group members	*IESO*	- Finalized Terms of Reference	April-May 2025
2	**Develop the Planning Forecast for the Region**			
	- Establish historical peak demand information	*IESO*	- Long-term planning forecast scenarios	April – July 2025
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast and if applicable/need be, high/low growth scenarios	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecasts	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	April – July 2025

	needs and identifying options for addressing needs			
4	**Complete system studies to identify needs over a twenty-year period** - Develop load flow base case, including system assumptions as identified in the key assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Aug - Nov 2025
5	**Develop Options and Alternatives**			
	Develop conservation options	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios - Deliverables staged according to the three phases	Dec 2025-Feb 2026
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
6	**Plan and Undertake Community & Stakeholder Engagement**			
	- Early engagement with local municipalities and Indigenous communities within the Region, First Nation communities who may have an interest in the Region, and the Métis Nation of Ontario	*All*	- Community and Stakeholder Engagement Plan - Input from local communities	Q3/Q4 2025
	- Develop communications materials	*All*		Q4 2025-Q1 2026
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		

7	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	March -May 2026
8a	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	June-August 2026
8b	**Review & publish IRRP report**	*IESO*	-	August-Oct 2026

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EXHIBIT 2B - TAB 2 - SCHEDULE 1: APPENDIX I SOUTH GEORGIAN BAY-MUSKOKA – NEEDS ASSESSMENT



NEEDS ASSESSMENT REPORT

South Georgian Bay - Muskoka

Date: August 27, 2025

Needs Assessment Report

South Georgian Bay - Muskoka

August 27, 2025

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: South Georgian Bay-Muskoka Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the South Georgian Bay - Muskoka and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region. Updates may be made based on the best available information throughout the planning process.

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 **South Georgian Bay - Muskoka** Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: April 29, 2025 **END DATE:** August 27, 2025

The second Regional Planning cycle for the **South Georgian Bay - Muskoka** Region was completed December 6, 2022 with the publication of the Regional Infrastructure Plan ("RIP") report - South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP).

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Considering these timelines, the 3rd Regional Planning cycle was triggered in **April 2025** for this Region. The planning horizon for this Needs Assessment ("NA") is ten years. A 20-year planning assessment is undertaken in the next phase of regional planning, i.e., IRRP and RIP phases.

The purpose and scope of the NA is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group (TWG) comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One Transmission. They provide input and relevant information for the region and undertake a technical assessment to identify the electrical infrastructure needs in the region. They collaborate to develop both summer and winter gross and net peak electricity demand forecasts (including input from municipalities), which form the basis for the technical assessment. The following are key considerations of the technical assessment:

a) Current and future station capacity and transmission adequacy.
b) System reliability needs and 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.

In this Needs Assessment, TWG has identified the following regional needs and recommendations:

Needs that require further regional coordination.

#	Need Location	Need Description
1	M6E/M7E (Supply Capacity)	Supply Capacity need identified on (Essa x Midhurst, Minden x Coopers Fls JCT). Further coordination is required to reaffirm need, solution and timing.
2	Alliston T3/T4 (Supply Capacity)	Alliston TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
3	Everett T1/T2 (Supply Capacity)	Everett TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
4	Midhurst T1/T2, T3/T4 (Supply Capacity)	Midhurst TS (T1/T2) and (T3/T4) are 230-44kV 125MVA transformer stations and will both exceed their normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
5	Claireville Area North and Flow North	Operational issues identified, will be studied in Bulk System Plan

Needs that do not require further regional coordination.

#	Need Location	Need Description
6	E8V/E9V (Asset Renewal + Supply Capacity)	Essa TS x Orangeville TS line section will be upgraded as per Ministry of Energy's – Energy for Generations report. This upgrade planned for 2029 will resolve supply capacity needs identified on section (Essa x Alliston JCT) and asset renewal needs. Further coordination is not required.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Corporation (Alectra)
- Hydro One Distribution
- InnPower
- Orangeville Hydro
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc
- NT Power Distribution
- Wasaga Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- n/a

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1. INTRODUCTION

The second cycle of the Regional Planning process for the South Georgian Bay - Muskoka Region was completed in December 2022 with the publication of the South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP). The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the South Georgian Bay - Muskoka Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

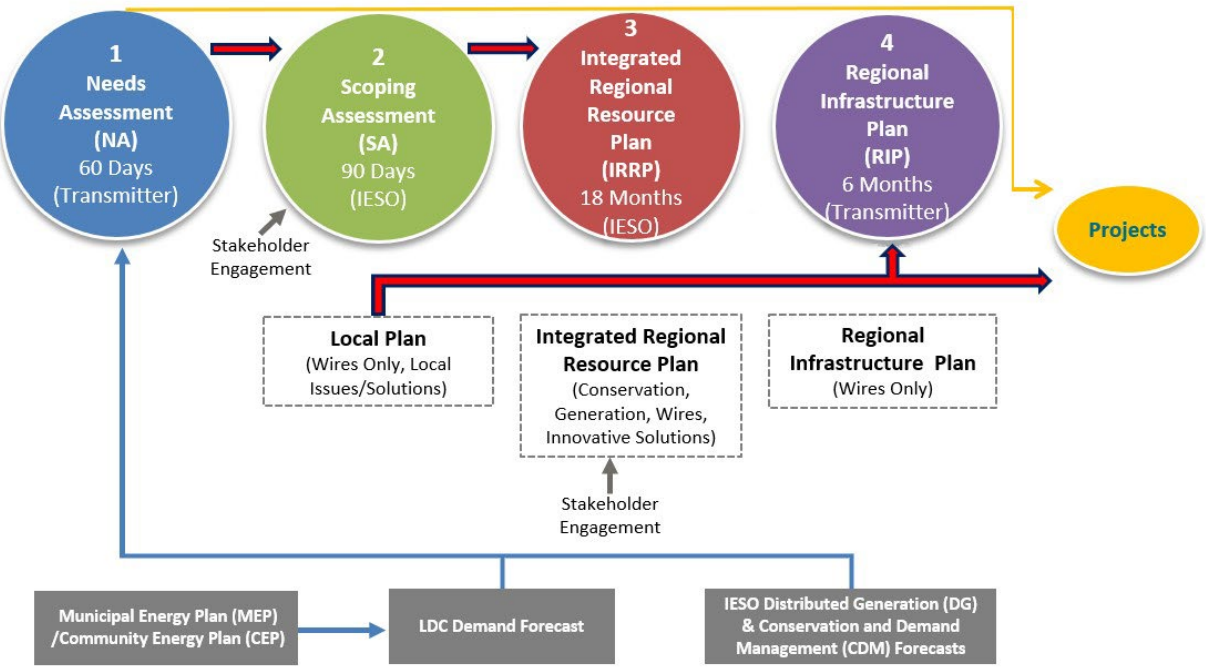


Figure 1: Regional Planning Process

This report was prepared by the South Georgian Bay - Muskoka Technical Working Group("TWG"), led by Hydro One Networks Inc. 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"). Participants of the TWG are listed below in Table 1.

Table 1: South Georgian Bay - Muskoka Region TWG Participants

Sr. no.	Name of TWG Participants
1	Independent Electricity System Operator (IESO)
2	Alectra Utilities Corporation (Alectra)
3	Hydro One Networks Inc. (Transmission & Distribution)
4	InnPower
5	Orangeville Hydro
6	Elexicon Energy
7	Lakeland Power
8	EPCOR Electricity Distribution Ontario Inc
9	NT Power Distribution
10	Wasaga Distribution Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. As such, the 3rd Regional Planning cycle was triggered for the South Georgian Bay - Muskoka region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the South Georgian Bay - Muskoka region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phase of the regional planning cycle to develop a preferred plan; and,
- 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 and/or no regional investment is required at this time and the need may be reviewed during the next regional planning 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"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The geographical boundaries of the South Georgian Bay - Muskoka region is shown in Figure 2 below.

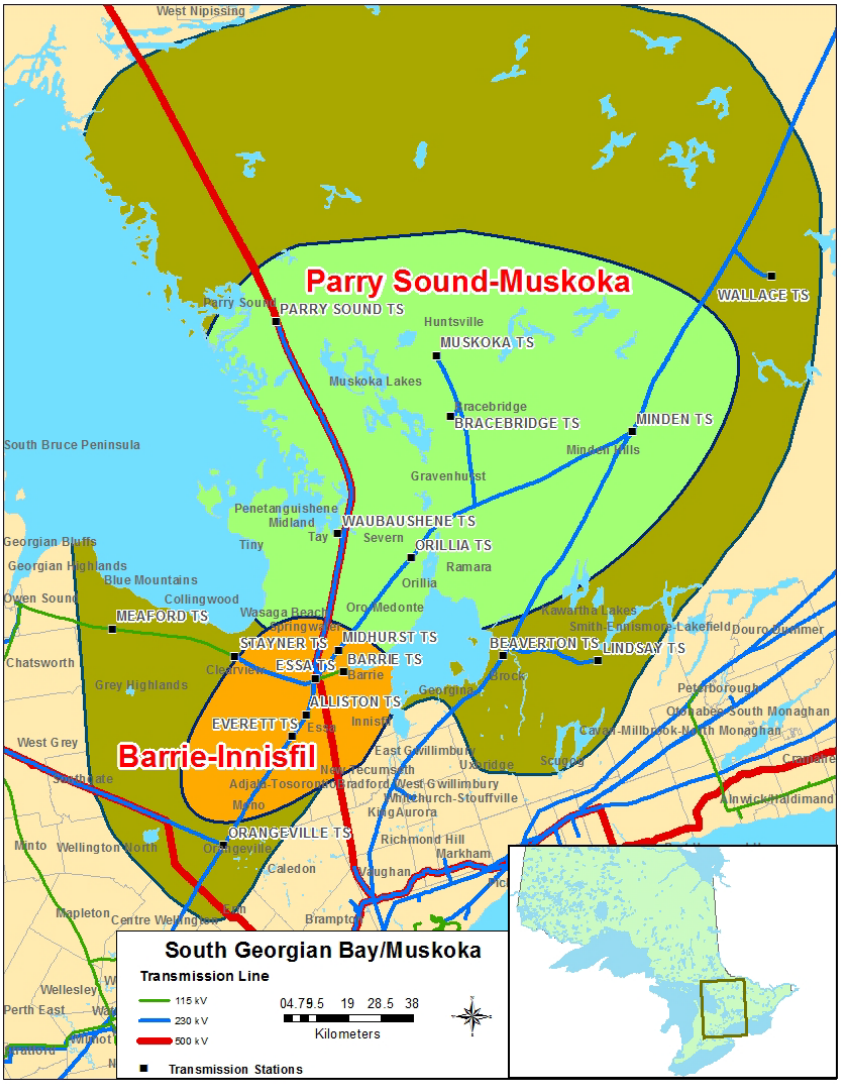


Figure 2: Map of South Georgian Bay - Muskoka Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the South Georgian Bay - Muskoka Region

115kV circuits	230kV circuits	Hydro One Transformer Stations		Generation Stations
S2S	D1M / D2M D3M / D4M E8V / E9V E20S / E21S E26 / E27 E28 / E29 M6E / M7E M80B / M81B	Alliston TS Barrie TS Beaverton TS Bracebridge TS Essa TS * Everett TS Lindsay TS Meaford TS Midhurst TS	Minden TS Muskoka TS Orangeville TS Orillia TS Parry Sound TS Stayner TS* Wallace TS Waubaushene TS	Henvey Inlet North /South) 700MW

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of South Georgian Bay - Muskoka region is shown in Figure 3 below.

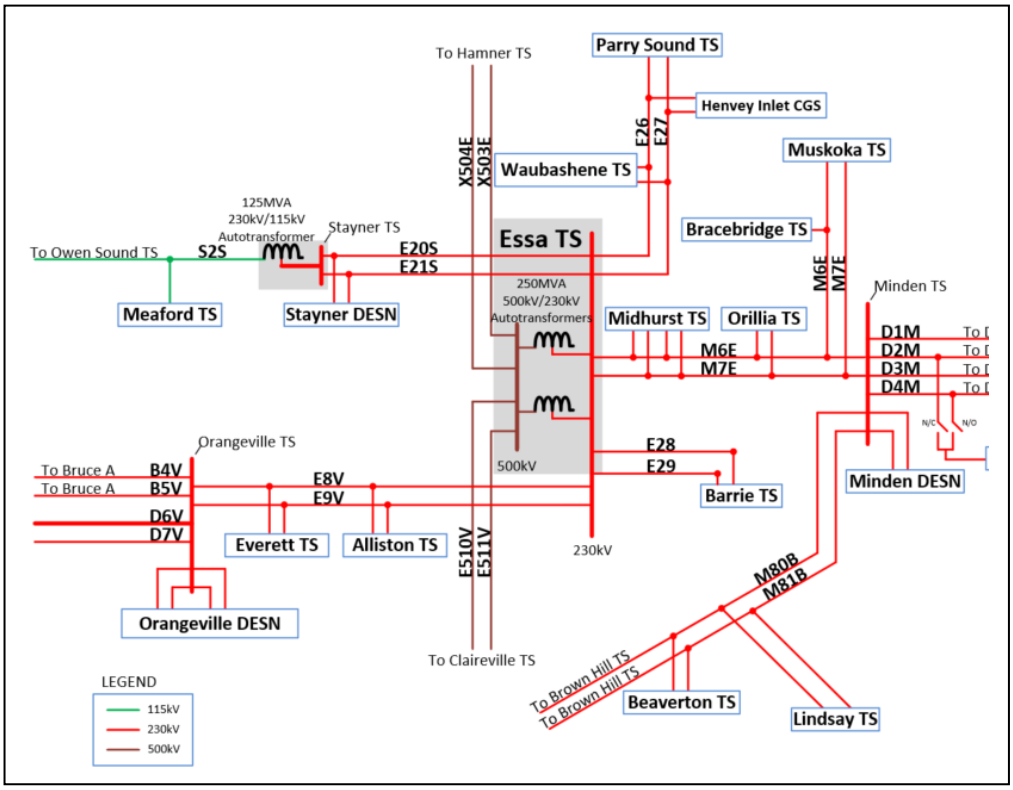


Figure 3: South Georgian Bay - Muskoka Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the **South Georgian Bay - Muskoka** NA. 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 Oct. 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 regional planning 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). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- **South Georgian Bay - Muskoka** 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g. through their MEPs & CEPs).
- Known capacity and reliability needs, operating issues, and/or major assets requiring replacement/ refurbishment; and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the **South Georgian Bay - Muskoka**.
- Captured 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

6. ASSESSMENT METHODOLOGY

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

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- System reliability and operational considerations.
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to "right-sizing"; and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on both summer and winter peak loads. Three load forecasts were developed i.e. Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenario was developed to conduct a sensitivity analysis to cover unforeseen

developments such as fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

- Consideration of existing or planned distributed energy resources

The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2034.
- The Region is marginally winter peaking; however, the assessment was done on both summer and winter peak loads due to summer equipment ratings being lower.
- Network line and auto-transformation capacity adequacy is assessed by using coincidence peak loads in the area.
- Load-serving station and radial line 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 Hydro One transformer stations is determined by the seasonal 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Normal planning supply capacity for LDC transformer stations is in accordance with LDC methodology.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Transmission-connected Resources (e.g. Generators) were set to historical generation output of 98% and 85% availability for the seasons under study, information provided by the IESO.

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the South Georgian Bay - Muskoka region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the South Georgian Bay - Muskoka region. The region's extreme summer/winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the actual 2024 summer peak extreme weather corrected loads. The extreme summer/winter weather correction factors were provided by Hydro One. The net extreme summer weather forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This

extreme summer/winter weather corrected net load forecast for the individual stations in the South Georgian Bay - Muskoka region is given in Appendix A.

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather these scenarios are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

Relevant information regarding system reliability and operational issues in the region as feedback provided by the IESO and Hydro One operation teams during the NA phase.

7. NEEDS

This section describes emerging new needs identified in the South Georgian Bay - Muskoka Region and/or updates on previously identified needs since the completion of Previous Regional Planning (RP) cycle.

Needs that were identified in the previous regional planning cycle with associated projects that were recently completed and reaffirmed needs that are underway are briefly described below with relevant updates and will not be discussed further in this report.

1. **Everett TS Station Capacity** - CT ratio of the low voltage transformer breaker CTs were modified in 2024. However, additional capacity needs are identified and will be studied in this cycle.
2. **Barrie TS Station Capacity** - Construct new 230/27.6kV 83MVA Innpower MTS and extend 230kV E28B/E29B circuits to connect. The planned in-service year is 2029.
3. **Waubaushene TS Station Capacity** – Replacing and upgrading existing 230/44kV 83MVA T5/T6 transformers with 125MVA units. The planned in-service year is 2028.
4. **M6E/M7E (Orillia TS x Coopers FLS JCT) Asset Replacement** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need has been postponed beyond the study period of this RP cycle. A new capacity need, however, has been identified and will be studied in this RP cycle.
5. **E8V/E9V (Orangeville TS x Essa JCT) Asset Replacement** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need was postponed to 2035 i.e., beyond the study period of this RP cycle. However, IESO has identified a capacity need via the Central & South Bulk study and System Impact Assessments, which will be discussed in this RP cycle.
6. **D1M/D2M (Minden TS x Otter Creek JCT)** – Updated condition assessments have confirmed that the conductor and key components remain in acceptable asset condition, as a result, this need has been postponed beyond the study period of this RP cycle.
7. **Wallace TS Asset Replacement** – T3/T4 transformers will be replaced with like for like 230/44kV 42MVA standard step-down transformer. The planned in-service year is in 2034.
8. **Midhurst TS Asset Replacement** – T4 transformer will be replaced with like for like 230/44kV 125MVA standard step-down transformer. The planned in-service year is in 2034.
9. **Orillia TS Asset Replacement** – T2 transformer will be replaced with like for like 230/44kV 125MVA standard step-down transformer. The planned in-service year is in 2026.
10. **Bracebridge TS Asset Replacement** – T1 transformer will be replaced with like for like 230/44kV 83MVA standard step-down transformer. The planned in-service year is in 2026.
11. **Alliston TS Asset Replacement** – T3/T4 transformers will be replaced with like for like 230/44kV 83MVA standard step-down transformers. The planned in-service year is in 2040. However, a new capacity need has been identified and will be studied in this RP cycle.

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

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or Updated from Previous RIP

Need Location	Need Description/Update	NA Report Section
Asset Renewal Needs		
No new Asset Renewal needs identified in this Regional Planning Cycle.		
Station Capacity Needs		
Alliston TS (T3/T4)	Projected to reach capacity in 2032	7.2.1
Everett TS (T1/T2)	Projected to reach capacity in 2030	7.2.2
Midhurst TS (T1/T2)	Projected to reach capacity in 2030	7.2.3
Midhurst TS (T3/T4)	Projected to reach capacity in 2029	7.2.4
Transmission Line Capacity Needs		
230kV M6E/M7E	Projected to reach capacity in mid-term	7.3.1
230kV E8V/E9V	Need identified by IESO in Central & South Bulk study and System Impact Assessments	7.3.2
System Reliability, Operation and Load restoration Needs		
Claireville Area North and Flow North	Operational issues identified, will be studied in the area Bulk System Plan	7.4

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and the TWG identified new asset renewal needs for major HV transmission equipment over the next 10 years in the **South Georgian Bay - Muskoka** Region. They are listed in Table 4 below. Hydro One is the only Transmission Asset Owner (TAO) in the Region

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

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

The asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, doing nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance costs and longer duration of customer outages.

Table 4: Major HV Transmission Assets Requiring Replacement in the SGB Muskoka Region

Station/Circuit	Need Description	Planned ISD
Orillia TS	T2 transformer will be replaced with new like for like 230/44kV 125MVA standard step-down transformers	2026
Bracebridge TS	T1 transformer will be replaced with new like for like 230/44kV 83MVA standard step-down transformers	2026
Wallace TS	T3/T4 transformers will be replaced with new like for like 230/44kV 42MVA standard step-down transformers	2034
Midhurst TS	T4 transformer will be replaced with new like for like 230/44kV 125MVA standard step-down transformers	2034

7.1.1 E8V/E9V (Orangeville TS x Essa JCT)

This double circuit 230kV transmission line was in-serviced in 1950. Based on asset condition assessment, this line section requires conductor refurbishment at the end of the study period (2035) to ensure supply reliability and safety is maintained. In conjunction with the existing asset renewal need, these circuits were identified to have a capacity need via the Central & South Bulk study and System Impact Assessments by IESO and recently announced in the *Energy For Generations*[1] report issued by the Ministry of Energy and Mines (June 2025) as a key investment to facilitate growth in the province and strengthen the north-south electricity corridor (more information in section 7.3.2). The in-service date requested in the report precedes the asset renewal upgrade timeline and the upgrade will naturally replace existing components installed on the line. It is recommended this need requires further coordination. The expected in-service date is 2029.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2034 for the 230kV and 115kV Transforming stations in the **South Georgian Bay - Muskoka** Region using the summer and winter peak load forecasts that were provided by the Technical Working Group. Based on the results, the following Station capacity needs have been identified during the study period:

7.2.1 Alliston TS (T3/T4)

Alliston TS (T3/T4) is a 230-44kV 50-83MVA Step Down transformer station supplied by the E8V/E9V circuits. This station presently has a summer 10-day LTR of 100MW and will exceed its normal supply capacity in 2032 based on the summer demand forecast.

Previous regional planning cycle identified these transformers would be replaced in 2030, however Hydro One has since revised its assessment on the condition of these units and delayed the replacement outside of the study period to 2040.

It is recommended the capacity need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.2 Everett TS (T1/T2)

Everett TS (T1/T2) is a 230-44kV 50-83MVA Step Down transformer station supplied by the E8V/E9V circuits. This station presently has a 10-day LTR of 107MW (sum) and 115MW (win) and will exceed its normal supply capacity in 2030 and 2033 respectively.

As a result of the findings in the previous cycle RIP, Hydro One modified the CT ratio of the low voltage transformer breaker CTs to increase the station capacity. This was completed in 2024 and helped to defer

[1] https://www.ontario.ca/page/energy-generations

a capacity need identified in the previous cycle. Everett TS load forecast continues to grow and irrespective of the recent modifications, station capacity needs continue to exist within the study period.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.3 Midhurst TS (T1/T2)

Midhurst TS (T1/T2) is a 230-44kV 75-125MVA Step Down transformer station supplied by the M6E/M7E circuits. This station presently has a 10-day LTR of 162MW (sum) and will exceed its normal supply capacity in 2030 based on the summer demand forecast.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.2.4 Midhurst TS (T3/T4)

Midhurst TS (T3/T4) is a 230-44kV 75-125MVA Step Down transformer station supplied by the M6E/M7E circuits. This station presently has a 10-day LTR of 149MW (sum) and will exceed its normal supply capacity in 2029 based on the summer demand forecast.

It is recommended this need be assessed and reaffirmed in the next phase of this regional planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2025-2034 for the 230kV and 115kV Transmission line circuits in the South Georgian Bay - Muskoka Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified during the study period:

7.3.1 230kV - M6E/M7E

The M6E/M7E circuits are 230kV transmission lines forming a critical path between Essa TS and Minden TS. Two sections of this circuit (Essa x Midhurst) and (Coopers Fls JCT x Minden) both exceed their Long Term Emergency (LTE) supply capacity during the study period and will require mitigating solutions to allow for increased flow. These needs were also documented in the previous cycle of regional planning and the TWG recommended to continue to monitor loading. Flows on this path are heavily influenced by area load and generation both within and outside of the SGB-Muskoka region.

It is recommended this need to be further explored in the next phase of this regional planning cycle.

7.3.2 230 kV - E8V/E9V

E8V/E9V circuits are 230kV transmission lines forming a critical path between Essa TS and Orangeville TS. These circuits supply customer transformer stations, carry system flows, and are incorporated into the FETT (Flow East Toward Toronto) interface limits. Based on the coincident load forecast, the Essa TS x Alliston JCT line section will exceed its supply capacity during the study period and will require mitigating solutions to allow for increased flows. This finding incorporates a higher growth scenario with the prospect of large industrial connected loads to be connected on the circuits.

In conjunction with the identified capacity need, these circuits were recently announced in the *Energy For Generations*[2] report issued by the Ministry of Energy and Mines (June 2025) as a key investment to facilitate growth in the province and strengthen the north-south electricity corridor. Also based on asset condition assessment, this line section requires conductor refurbishment at the end of the study period (2035) to ensure supply reliability and safety is maintained.

This investment to upgrade these circuits is presently underway with an in-service date planned for 2029. This investment will address the supply capacity needs identified above, including asset replacement. No further regional coordination is required.

7.3.3 115kV Circuits

No Supply capacity needs on 115kV circuit were identified during the study period.

[2] https://www.ontario.ca/page/energy-generations

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service.

Operational needs presented to the TWG consisted of two legacy concerns: Load restoration (M6E/M7E) and Long Term Emergency (LTE) overloading (M6E/M7E)

Load Restoration criteria continue to be respected in the region and were recently addressed by the installation of 230kV motorized in-line switches on the M6E/M7E circuits. Thermal overloading has also been reaffirmed in this Needs Assessment and will be further studied in future stages of regional planning.

Additional operational concerns on area interface limits on the CLAN (Claireville Area North) and FN (Flow North) limits were identified. The TWG acknowledges that increased flows in the overall area impact operational limits, however this will be further assessed in bulk area studies outside of regional planning.

Given the above needs have either already been identified or will be studied outside of this process, no other new significant system reliability, operating and restoring issues have been identified for this Region.

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 investments. The TWG determined that the key electric demand driver in the South Georgian Bay - Muskoka region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer/winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

Table 5: Impact of Sensitivity Analysis on Station/Line capacity Needs in the Region

		Summer Growth Scenario			Winter Growth Scenario		
Sr.no.	Need Identified	Low	Normal	High	Low	Normal	High
1	Alliston (T3/T4)	-	2032	2028	-	-	2033
2	Alliston (T2)	-	-	-	-	-	-
3	Barrie (T3/T4)	-	2031	2028	-	-	-
4	Beaverton (T3/T4)	-	-	-	-	-	-
5	Bracebridge (T1)	-	-	-	-	-	-
6	Everett (T1/T2)	-	2030	2027	-	2033	2029
7	Lindsay (T1/T2)	-	-	2034	-	-	2032
8	Meaford (T1/T2)	-	-	-	-	-	
9	Midhurst (T1/T2)	-	2030	2028	-	-	2032
10	Midhurst (T3/T4)	-	2029	2027	-	-	-
11	Minden (T1/T2)	-	-	-	-	-	-
12	Muskoka (T1/T2)	-	-	2030	-	-	2031
13	Orangeville (T1/T2)	-	-	2030	-	-	2034
14	Orangeville (T3/T4)	-	-	-	-	-	-
15	Orillia (T1/T2)	-	-	-	-	-	-
16	Parry Sound (T1/T2)	-	-	-	-	-	-
17	Stayner (T3/T4)	-	-	-	-	-	-
18	Wallace (T3/T4)	-	-	2029	-	-	2030
19	Waubashene (T5/T6)	2030	2028	2026	2034	2028	2028

The sensitivity analysis identified the additional capacity needs at the end of the study period. High growth scenario forecasts introduce additional supply capacity needs at Lindsay TS, Midhurst TS, Muskoka TS, and Wallace TS. These needs will be assessed again during the next phase of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Table 6: Needs that Require Further Regional Coordination

#	Need Location	Need Description
1	M6E/M7E (Supply Capacity)	Supply Capacity need identified on (Essa x Midhurst, Minden x Coopers Fls JCT). Further coordination is required to reaffirm need, solution and timing.
2	Alliston T3/T4 (Supply Capacity)	Alliston TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
3	Everett T1/T2 (Supply Capacity)	Everett TS (T3/T4) is a 230-44kV 83MVA transformer station and will exceed its normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
4	Midhurst T1/T2, T3/T4 (Supply Capacity)	Midhurst TS (T1/T2) and (T3/T4) are 230-44kV 125MVA transformer stations and will both exceed their normal supply capacity within the study period. Further coordination is required to reaffirm need, solution and timing.
5	Claireville Area North and Flow North	Operational issues identified, will be studied in Bulk System Plan

Table 7: Needs that Do Not Require Further Regional Coordination

#	Need Location	Need Description
6	E8V/E9V (Asset Renewal + Supply Capacity)	Essa TS x Orangeville TS line section will be upgraded as per Ministry of Energy's – Energy for Generations report. This upgrade planned for 2029 will resolve supply capacity need identified on section (Essa x Alliston JCT) and asset renewal needs. Further coordination is not required.

List of LDC(s) to be involved in further regional planning phases:

- Alectra Utilities Corporation (Alectra)
- Hydro One Distribution
- InnPower
- Orangeville Hydro
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc
- NT Power Distribution
- Wasaga Distribution Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- n/a

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. March 31, 2025)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. August 14, 2025)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Hydro One Networks Inc, South Georgian Bay-Muskoka Regional Infrastructure Plan (RIP) (issue December 22, 2022)

Appendix A: Extreme Summer/Winter Weather Adjusted Net Load Forecast

Table A.1:

South Georgian Bay - Muskoka Non-Coincident- Normal Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	40	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	75	78	81	84	88	91	95	99	103	107	111
Barrie TS	T3/T4	179	170	87	110	120	131	138	146	162	177	189	200	210
Beaverton TS	T3/T4	203	193	72	59	60	61	63	64	68	70	71	73	75
Bracebridge TS	T1	83	75	35	38	39	39	39	40	40	41	41	42	42
Everett TS	T1/T2	119	107	82	85	90	95	100	106	113	120	127	134	142
Lindsay TS	T1/T2	169	161	76	68	71	74	77	80	89	93	97	101	106
Meaford TS	T1/T2	55	52	33	33	33	33	34	34	34	34	35	35	35
Midhurst TS	T1/T2	171	162	124	125	132	137	132	144	163	165	166	175	177
Midhurst TS	T3/T4	166	149	114	114	116	131	135	150	154	157	161	166	170
Minden TS	T1/T2	138	124	48	44	44	44	44	44	47	47	47	47	48
Muskoka TS	T1/T2	178	169	128	131	135	138	141	145	148	152	156	159	163
Orangeville TS	T1/T2	128	115	74	76	78	81	84	87	91	94	97	101	105
Orangeville TS	T3/T4	180	171	93	93	95	97	98	100	103	105	107	109	111
Orillia TS	T1/T2	162	154	102	87	88	90	91	93	109	111	112	114	116
Parry Sound TS	T1/T2	128	115	51	52	54	55	56	58	59	61	62	63	65
Stayner TS	T3/T4	191	181	128	126	126	126	126	127	128	128	129	129	130
Wallace TS	T3/T4	54	49	42	42	42	43	43	44	44	45	46	46	47
Waubaushene TS	T5/T6	99	94	97	89	92	94	96	98	105	108	110	113	116

Table A.2:

South Georgian Bay - Muskoka – Coincident – Normal Growth Net Load Forecast – (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	22	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	72	75	78	81	84	87	91	95	99	103	107
Barrie TS	T3/T4	179	170	65	67	70	73	77	80	84	88	92	96	101
Beaverton TS	T3/T4	203	193	70	57	58	59	61	62	66	67	69	71	73
Bracebridge TS	T1	83	75	29	29	29	29	30	30	30	31	31	31	32
Everett TS	T1/T2	119	107	77	80	85	89	94	100	106	112	119	126	134
Lindsay TS	T1/T2	169	161	66	57	60	63	66	69	77	80	84	87	91
Meaford TS	T1/T2	55	52	31	30	30	30	30	30	30	30	30	30	30
Midhurst TS	T1/T2	171	162	113	109	113	116	121	125	134	139	144	149	155
Midhurst TS	T3/T4	166	149	105	72	74	76	79	81	83	86	89	91	94
Minden TS	T1/T2	138	124	37	33	33	33	33	33	36	37	37	37	37
Muskoka TS	T1/T2	178	169	120	104	105	108	110	111	119	121	123	125	128
Orangeville TS	T1/T2	128	115	37	37	38	40	41	42	44	46	48	49	51
Orangeville TS	T3/T4	180	171	88	88	89	91	92	94	97	99	101	103	105
Orillia TS	T1/T2	162	154	95	79	81	82	84	85	101	103	104	106	108
Parry Sound TS	T1/T2	128	115	47	43	44	45	47	47	49	50	51	51	52
Stayner TS	T3/T4	191	181	125	123	123	123	123	123	125	125	125	126	127
Wallace TS	T3/T4	54	49	31	31	31	32	32	32	33	33	34	34	35
Waubaushene TS	T5/T6	99	94	96	88	90	92	94	97	104	106	109	112	114

Table A.3:

South Georgian Bay - Muskoka Region Non-Coincident–High Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	40	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	75	81	87	94	102	110	118	128	138	149	161
Barrie TS	T3/T4	179	170	87	110	128	148	172	199	231	268	311	361	419
Beaverton TS	T3/T4	203	193	72	65	74	83	94	105	121	135	151	170	190
Bracebridge TS	T1	83	75	35	38	39	41	42	43	44	46	47	48	50
Everett TS	T1/T2	119	107	82	91	102	115	130	147	166	187	211	239	270
Lindsay TS	T1/T2	169	161	76	71	79	87	95	105	120	131	144	157	172
Meaford TS	T1/T2	55	52	33	33	34	35	35	36	37	37	38	39	40
Midhurst TS	T1/T2	171	162	124	134	145	156	169	182	197	212	229	248	268
Midhurst TS	T3/T4	166	149	114	125	138	151	167	183	202	222	244	268	295
Minden TS	T1/T2	138	124	48	44	45	45	45	46	50	50	51	51	52
Muskoka TS	T1/T2	178	169	128	135	141	148	155	162	170	178	187	196	205
Orangeville TS	T1/T2	128	115	74	79	85	92	99	107	115	125	134	145	157
Orangeville TS	T3/T4	180	171	93	96	101	105	110	116	122	128	135	141	148
Orillia TS	T1/T2	162	154	102	89	93	97	102	106	126	131	136	142	148
Parry Sound TS	T1/T2	128	115	51	54	57	59	62	65	69	72	76	80	83
Stayner TS	T3/T4	191	181	128	128	130	132	135	137	141	144	147	150	153
Wallace TS	T3/T4	54	49	42	43	44	46	47	49	51	52	54	56	58
Waubaushene TS	T5/T6	99	94	98	90	96	101	107	114	121	128	136	144	152

Table A.4:

South Georgian Bay – Muskoka Coincident High Growth Net Load Forecast (Sum) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	22	38	39	51	61	60	59	59	58	58	57
Alliston TS	T3/T4	111	100	72	76	80	85	90	96	102	108	114	121	128
Barrie TS	T3/T4	179	170	65	69	75	81	87	94	101	109	118	128	138
Beaverton TS	T3/T4	203	193	70	58	61	64	67	70	76	79	83	87	91
Bracebridge TS	T1	83	75	29	29	30	30	31	31	32	33	33	34	35
Everett TS	T1/T2	119	107	77	82	90	97	106	115	126	137	149	162	177
Lindsay TS	T1/T2	169	161	66	59	63	67	72	77	87	92	98	105	112
Meaford TS	T1/T2	55	52	31	31	31	31	31	32	32	33	33	33	34
Midhurst TS	T1/T2	171	162	113	110	116	122	129	135	147	155	163	171	180
Midhurst TS	T3/T4	166	149	105	74	77	81	85	89	94	99	104	109	114
Minden TS	T1/T2	138	124	37	33	34	34	34	35	38	39	39	40	40
Muskoka TS	T1/T2	178	169	120	104	107	110	113	115	124	127	129	132	136
Orangeville TS	T1/T2	128	115	37	38	40	42	45	47	51	54	57	60	64
Orangeville TS	T3/T4	180	171	88	89	93	96	100	104	108	113	117	122	127
Orillia TS	T1/T2	162	154	95	81	84	86	89	92	110	113	117	121	125
Parry Sound TS	T1/T2	128	115	47	44	46	47	50	51	54	56	57	59	61
Stayner TS	T3/T4	191	181	125	125	127	129	131	134	137	140	143	146	149
Wallace TS	T3/T4	54	49	31	31	32	33	34	35	36	37	39	40	41
Waubaushene TS	T5/T6	99	94	96	90	94	97	102	106	115	120	125	131	136

Table A.5:

South Georgian Bay - Muskoka Non-Coincident- Normal Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	34	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	59	61	64	66	69	71	74	77	80	84	87
Barrie TS	T3/T4	190	181	93	93	97	102	107	112	124	135	144	152	159
Beaverton TS	T3/T4	224	213	82	82	84	86	88	90	92	94	97	99	101
Bracebridge TS	T1	83	75	40	40	41	41	42	42	43	43	44	44	45
Everett TS	T1/T2	128	115	68	72	77	81	86	92	98	104	110	118	125
Lindsay TS	T1/T2	192	182	100	102	107	111	115	120	125	129	134	140	145
Meaford TS	T1/T2	61	58	42	44	44	43	44	44	47	47	46	46	46
Midhurst TS	T1/T2	193	183	126	125	131	136	130	141	153	153	153	160	161
Midhurst TS	T3/T4	191	172	94	90	92	93	95	97	99	100	102	104	106
Minden TS	T1/T2	146	131	57	53	53	53	53	54	58	58	58	58	59
Muskoka TS	T1/T2	209	199	157	147	150	154	157	159	164	167	170	173	176
Orangeville TS	T1/T2	145	131	60	59	62	66	69	73	77	81	84	88	92
Orangeville TS	T3/T4	198	188	104	102	104	108	110	113	118	121	123	126	129
Orillia TS	T1/T2	184	175	107	99	101	103	105	107	118	120	123	125	128
Parry Sound TS	T1/T2	135	122	64	62	64	65	68	68	71	72	73	74	75
Stayner TS	T3/T4	213	202	153	149	149	150	151	151	157	158	159	160	161
Wallace TS	T3/T4	60	54	44	45	45	46	47	48	49	49	50	51	52
Waubaushene TS	T5/T6	109	104	88	93	94	94	107	108	108	108	109	109	110

Table A.6:

South Georgian Bay - Muskoka – Coincident – Normal Growth Net Load Forecast – (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	11	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	51	53	55	57	59	61	64	66	69	72	75
Barrie TS	T3/T4	190	181	51	53	54	56	57	59	60	62	64	65	67
Beaverton TS	T3/T4	224	213	81	81	83	85	87	89	91	93	95	97	100
Bracebridge TS	T1	83	75	32	33	33	34	34	34	35	35	35	36	36
Everett TS	T1/T2	128	115	65	68	73	77	82	87	93	99	105	112	119
Lindsay TS	T1/T2	192	182	90	92	95	99	103	107	111	116	120	125	130
Meaford TS	T1/T2	61	58	38	35	35	35	35	35	38	37	37	37	37
Midhurst TS	T1/T2	193	183	114	118	121	125	129	132	135	139	143	147	152
Midhurst TS	T3/T4	191	172	94	96	98	99	101	103	105	106	108	110	113
Minden TS	T1/T2	146	131	56	52	52	53	53	53	57	57	58	58	58
Muskoka TS	T1/T2	209	199	136	126	128	132	135	137	141	144	146	149	152
Orangeville TS	T1/T2	145	131	34	32	34	37	39	41	44	46	48	50	52
Orangeville TS	T3/T4	198	188	99	96	99	102	104	107	112	115	117	120	123
Orillia TS	T1/T2	184	175	107	98	100	102	105	106	118	120	122	124	127
Parry Sound TS	T1/T2	135	122	58	56	57	58	61	62	63	64	65	67	68
Stayner TS	T3/T4	213	202	153	149	149	150	151	151	157	158	159	160	161
Wallace TS	T3/T4	60	54	38	38	39	40	40	41	42	42	43	44	45
Waubaushene TS	T5/T6	109	104	86	88	90	91	93	95	96	98	100	102	104

Table A.7:

South Georgian Bay - Muskoka Region Non-Coincident – High Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	34	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	59	64	69	74	80	87	94	102	110	119	129
Barrie TS	T3/T4	190	181	93	99	104	111	117	124	132	140	148	157	167
Beaverton TS	T3/T4	224	213	82	85	89	94	99	104	109	115	121	128	135
Bracebridge TS	T1	83	75	40	41	43	44	45	47	48	50	51	53	55
Everett TS	T1/T2	128	115	68	77	87	98	111	125	141	160	181	205	232
Lindsay TS	T1/T2	192	182	100	107	116	125	136	147	159	172	186	202	219
Meaford TS	T1/T2	61	58	42	43	44	45	46	46	47	48	49	50	51
Midhurst TS	T1/T2	193	183	126	135	133	141	150	158	168	178	189	201	214
Midhurst TS	T3/T4	191	172	94	100	106	112	119	126	133	141	150	159	168
Minden TS	T1/T2	146	131	57	53	54	54	55	56	60	61	62	63	63
Muskoka TS	T1/T2	209	199	157	151	158	166	174	181	191	199	208	217	227
Orangeville TS	T1/T2	145	131	60	62	68	76	83	90	100	109	119	130	142
Orangeville TS	T3/T4	198	188	104	105	110	117	123	130	139	147	154	162	171
Orillia TS	T1/T2	184	175	107	101	106	111	116	121	136	142	148	154	161
Parry Sound TS	T1/T2	135	122	64	64	67	70	75	78	82	85	89	93	97
Stayner TS	T3/T4	213	202	153	151	154	157	161	165	173	177	180	185	189
Wallace TS	T3/T4	60	54	44	46	48	50	52	54	56	58	61	64	66
Waubaushene TS	T5/T6	109	104	88	92	97	101	106	112	117	123	129	136	143

Table A.8:

South Georgian Bay – Muskoka Coincident High Growth Net Load Forecast (Winter) MW

Station	DESN ID	LTR (MVA)	LTR(MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Alliston TS	T2	83	75	11	31	31	44	55	55	55	55	55	55	55
Alliston TS	T3/T4	128	115	51	54	57	60	64	68	72	77	81	86	92
Barrie TS	T3/T4	190	181	51	54	57	60	63	66	69	73	77	81	85
Beaverton TS	T3/T4	224	213	81	82	86	90	94	97	101	106	110	115	120
Bracebridge TS	T1	83	75	32	33	34	35	35	36	37	38	38	39	40
Everett TS	T1/T2	128	115	65	70	77	83	91	99	108	118	129	141	154
Lindsay TS	T1/T2	192	182	90	94	100	106	113	120	127	135	144	153	163
Meaford TS	T1/T2	61	58	38	35	36	36	37	37	40	41	41	42	42
Midhurst TS	T1/T2	193	183	114	120	127	134	141	147	155	163	171	180	190
Midhurst TS	T3/T4	191	172	94	98	102	107	111	115	120	125	130	136	142
Minden TS	T1/T2	146	131	56	53	54	56	57	58	64	65	66	68	70
Muskoka TS	T1/T2	209	199	136	129	135	143	150	156	165	172	179	188	196
Orangeville TS	T1/T2	145	131	34	33	35	39	41	44	48	51	54	58	61
Orangeville TS	T3/T4	198	188	99	98	102	108	113	117	125	130	136	142	148
Orillia TS	T1/T2	184	175	107	100	103	107	111	115	128	132	136	140	145
Parry Sound TS	T1/T2	135	122	58	56	58	59	62	63	66	67	69	70	72
Stayner TS	T3/T4	213	202	153	151	154	157	161	165	173	177	180	185	189
Wallace TS	T3/T4	60	54	38	39	40	41	43	44	45	47	48	50	52
Waubaushene TS	T5/T6	109	104	86	89	92	95	98	101	104	107	111	115	118

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Alliston TS	230/44	E8V/E9V
2	Barrie TS	230/44	E28/E29
3	Beaverton TS	230/44	M80B/M81B
4	Bracebridge TS	230/44	M6E
5	Everett TS	230/44	E8V/E9V
6	Lindsay TS	230/44	M80B/M81B
7	Meaford TS	230/44	S2S
8	Midhurst TS	230/44	M6E/M7E
9	Minden TS	230/44	Minden TS
10	Muskoka TS	230/44	M6E/M7E
11	Orangeville TS	230/44/27.6	Orangeville TS
12	Orillia TS	230/44	M6E/M7E
13	Parry Sound TS	230/44	E26/E27
14	Stayner TS	230/115/44	E20S/E21S
15	Wallace TS	230/44	D2M/D4M
16	Waubaushene TS	230/44	E26/E27

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations		Circuit ID	Voltage (kV)
1.	Essa TS	Stayner TS	E20/E21S	230
2.	Essa TS	Parry Sound TS	E26/E27	230
3.	Essa TS	Minden TS	M6E/M7E	230
4.	Minden TS	Des Joachims TS	D1M/D2M	230
5.	Minden TS	Des Joachims TS	D3M/D4M	230
6.	Minden TS	Brown Hill TS	M80B/M81B	230
7.	Essa TS	Barrie TS	E28/E29	230
8.	Stayner TS	Owen Sound TS	S2S	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Alectra Utilities
3	InnPower
4	Orangeville Hydro
5	Elexicon Energy
6	Lakeland Power
7	EPCOR Electricity Dist. Ontario Inc.
8	NT Power Distribution Ltd.
9	Wasaga Distribution Inc.

Appendix E: List of Municipalities in the South Georgian Bay - Muskoka Region

	Name of Municipality				
1	City of Barrie	19	Town of Kearney	37	Township of McKellar
2	City of Kawartha Lakes	20	Town of Midland	38	Township of McMurich
3	City of Orillia	21	Town of Midland	39	Township of Mulmur
4	County of Haliburton	22	Town of Mono	40	Township of Muskoka Lakes
5	Grey Highlands	23	Town of New Tecumseth	41	Township of Nipissing
6	Municipality of Callander	24	Town of Orangeville	42	Township of Perry
7	Municipality of Magnetawan	25	Town of Parry Sound	43	Township of Ryerson
8	Municipality of Meaford	26	Town of Penetanguishene	44	Township of Seguin
9	Municipality of Powassan	27	Town of Shelburne	45	Township of Severn
10	Municipality of Whitestone	28	Town of Wasaga Beach	46	Township of Southgate
11	Owen Sound	29	Township of Armour	47	Township of Springwater
12	South Gate	30	Township of Carling	48	Township of Strong
13	Town of Bracebridge	31	Township of Clearwater	49	Township of The Archipelago
14	Town of Collingwood	32	Township of Essa	50	Township of Tiny
15	Town of Gravenhurst	33	Township of Georgian Bay	51	Village of Burk Falls
16	Town of Huntsville	34	Township of Georgian Bluffs	52	Village of South River
17	Town of Innisfil	35	Township of Lake of Bays	53	Village of Sundridge
18	Town of Joly	36	Township of McDougall		

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
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
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

Acronym	Description
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
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
RAS	Remedial Action Scheme
SS	Switching Station
TS	Transformer Station

PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

1. PERFORMANCE MEASURES

Distributors are expected to summarize objectives for continuous improvement (e.g., reliability improvement, number of replaced assets, and other desired outcomes) the distributor set out to address in its last DSP and to discuss whether these objectives have been achieved or not. For objectives not achieved, a distributor should explain how it affects this DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in this DSP Section.

Elexicon is committed to continuous improvement by consistently measuring and monitoring its performance. The performance measures tracked by Elexicon align with the OEB's "Scorecard-Performance Measures" for electricity distributors, as listed below:

- Service Quality
- Customer Satisfaction
- Safety
- System Reliability
- Asset Management
- Cost Control
- Connection of Renewable Generation
- Financial Ratios

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is designed to track and show Elexicon's performance results over time and helps benchmark its performance and improvement against other utilities and best practices. Table 1 below summarizes Elexicon's performance during historical years from 2020 to 2024.

Explanations for any missed targets, including the impact on the DSP and any associated improvements, are detailed in the following sub-sections.

In addition to the standard performance scorecard, Elexicon Energy has developed 10 DSP-specific custom scorecard metrics for the 2027-2031 rate term. These metrics have been developed to support enhanced transparency and alignment between Elexicon's asset management objectives and the planned 2027 to 2031 investment program.

These metrics reflect the anticipated outcomes associated with the proposed capital and maintenance portfolio of investments and are therefore dependent on the level of investment ultimately approved through this DSP. As with any long-term forecast, the metrics may be influenced by changes in underlying assumptions, including material increases in non-discretionary work within the System Access and Reactive Capital categories, which may necessitate the reallocation of planned resources and adjustments to program pacing.

These metrics complement the Ontario Energy Board's Electricity Utility Scorecard by capturing key performance areas unique to Elexicon's 2027-2031 rate application period, and include items such as system reliability, capacity, asset management and cost control. These performance metrics provide a structured framework to monitor key aspects of reliability, capacity, asset health, and cost performance as they pertain to the DSP capital and maintenance investment plans, supporting informed decision-making for each metric. Targeted performance outcomes for these metrics have been aligned with the capital and maintenance balanced investments planned for the 2027-2031 rate period and these targets may be adjusted as investment plans evolve. Table 1 below presents Elexicon's custom scorecard metrics followed by a detailed description of each performance metric and historical performance (where available):

1.1 Performance Scorecard

Table 1 shows Elexicon's performance on the measures of the OEB's Performance Scorecard.

Table 1: OEB Scorecard Performance Measures

Performance Outcome	Measure	Metric	2020	2021	2022	2023	2024	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	93.74%	95.97%	96.94%	98.57%	98.77%	90%
		Scheduled Appointments Met on Time	98.80%	99.96%	98.01%	99.12%	99.45%	90%
		Telephone Calls Answered on Time	61.89%	75.99%	76.06%	72.35%	75.9%	65%
	Customer Satisfaction	First Contact Resolution	89.30%	93.00%	91.70%	88.97%	90.42%	No target
		Billing Accuracy	99.60%	99.75%	99.82%	99.87%	99.91%	98%
		Customer Satisfaction Survey	97.00%	97.00%	90.00%	90.00%	95.00%	No target
Operational Effectiveness	Safety	Level of Public Awareness	84.00%	87.00%	87.00%	89.00%	89.00%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	0	2	0	0	1
		Serious Electrical Incident Index Rate per 10, 100, 1000 km of line	0.000	0.000	0.510	0.000	0	0.146
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	1.37	1.17	1.71	1.37	1.71	1.35

Performance Outcome	Measure	Metric	**2020**	**2021**	**2022**	**2023**	**2024**	Target
		Ave. Number of Times that Power to a Customer is Interrupted	1.01	1.12	1.19	0.97	1.16	1.69
	Asset Management	Distribution System Plan Implementation Progress	76.81%	94.00%	92.48%	116.67%	114.79%	No target
	Cost Control	Efficiency Assessment	3	3	3	3	3	No target
		Total Cost per Customer	$630	$652	$704	$794	$834	No target
		Total Cost per km of Line	$27,593	$28,531	$31,028	$34,985	$36,504	No target
Public Policy Responsiveness	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected on Time	100.00%	100.00%	100.00%	100.00%	100.00%	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.29	1.46	0.33	0.83	0.76	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.07	1.18	1.33	1.46	1.62	No target
		Regulatory ROE – Deemed (included in rates)	9.43%	9.43%	9.43%	9.43%	9.43%	No target
		Regulatory ROE - Achieved	6.80%	6.87%	4.86%	5.15%	5.39%	No target

1

A review of Elexicon's historical performance above indicated that Elexicon has largely met or exceeded expectation over the historical periods, with the following exceptions:

Telephone Calls Answered on Time:

In 2020, Elexicon's Customer Service Representatives responded to 115,108 customer telephone inquiries. 61.89% of the calls were answered within 30 seconds, which is slightly below the OEB target of 65%. The impact of COVID-19 in the spring of 2020, specifically the need for Elexicon's customer service representatives to work from home, negatively impacted its ability to respond to telephone inquiries. In addition to technology challenges introduced with the work-from-home model, Elexicon experienced a higher volume of telephone inquiries than expected due to customer inquiries related to the COVID-19 Energy Assistance Program ("CEAP"), as well as a higher number of calls from customers inquiring about its Arrears Management Program and Customer Choice Program. Elexicon implemented a number of operational improvements that contributed to the strong recovery and sustained performance from 2021 through 2024, including system and technology performance improvements as well as increased staffing as it remains committed to improving responsiveness to customer telephone inquiries in 2021.

Serious Electrical Incident Index Rate:

Elexicon experienced an elevated Serious Electrical Incident Index Rate of 0.510 in 2022, exceeding the OEB's target of 0.146. This was due to two serious electrical incidents that occurred during the reporting period. Importantly, both incidents were the result of activities beyond Elexicon's direct control. One involved inadvertent contact with electrical infrastructure by a construction contractor while moving scaffolding. The second was caused by a homeowner trimming trees in their backyard, which led to contact with overhead wires.

In response to these incidents, Elexicon investigated each reported incident and deployed a member from their Health, Safety and Environment team to educate the members of public involved in the incident with electrical powerline safety education. Elexicon believes a continued focus on education will assist in reducing the risk of serious electrical incidents in the future.

SAIDI:

In 2020, SAIDI was slightly above the OEB's target of 1.35 hours in 2020, reporting a result of 1.37 hours. The top three contributors to SAIDI in 2020 were Human Element (23%), Tree contacts (22%) and Defective Equipment (21%). The increase was primarily driven by a major outage caused by equipment failure, which resulted in approximately 50,000 customer hours of interruption (CHI).

In 2022, SAIDI rose sharply to 1.71 hours, above the OEB target, due to a combination of severe weather events and station equipment failures. The top three contributor to SAIDI in 2022 were Defective Equipment (23%), Adverse Weather (20%) and Tree Contacts (17%). While some of the storms were substantial, they did not meet the threshold for exclusion as Major Event Days (MEDs). These events were placed considerable strain on the system and resulted in 59,124 CHI.

In 2023, performance improved with SAIDI returning to 1.37 hours although Elexicon continued to face challenges with its aging asset infrastructure. The top three contributors to SAIDI in 2023 were Defective Equipment (40%), Tree Contacts and Foreign Interference (14%). The reduction in SAIDI was primarily attributed to a decrease in adverse weather and tree contacts events due to improved weather in 2023 in Elexicon Service areas. This contributed to lower tree contacts and adverse weather-related outages compared to 2022.

In 2024, SAIDI rose sharply to 1.71 hours, similar to 2022 levels and above the OEB target. This increase was mainly attributed to a rise in Defective Equipment (34%), Tree contacts (26%), Foreign Interference (15%), and Unknowns (15%) related outages compared to 2023.

Elexicon has implemented a range of intervention measure in response to SAIDI performance trends. Elexicon has reprioritized investments in its critical maintenance programs such as reinstating insulator washing and refocused capital investments on areas with known reliability concerns. Short interval control meetings for reliability have been implemented to ensure that reliability results are continuously reviewed across Elexicon's service territory to identify trends and corresponding mitigation work. Additionally, Elexicon also continues to advance its distribution automation strategy and conduct regular reviews of network configurations to identify opportunities for feeder and station-level redundancy. These efforts

have resulted in maintaining the current system reliability, but Elexicon continues to face challenges in making significant improvements particularly due to a rise in equipment failures due to aging and deteriorating assets.

1.2 Custom Scorecard Metrics

This section is intended to capture any customer scorecard metrics proposed by the distributor that are not part of the Ontario Energy Board's (OEB) standard scorecard requirements. These custom metrics should reflect the distributor's unique customer engagement strategies, service improvement initiatives, or performance areas that are critical to their local context but not currently included in the OEB's prescribed performance categories.

Elexicon Energy has developed 10 custom performance metrics in its Customer Performance Scorecard for the 2027-2031 rate term. These metrics are presented in Table 2 below, followed by a detailed description of each performance metric and historical performance (where available):

Table 2: Elexicon's Custom Performance Scorecard

Performance Outcomes	Performance Categories	Metrics	Target	Notes
Operational Effectiveness	System Reliability	SAIDI (#) This measure reports the projected System Average Interruption Duration Index (SAIDI), excluding major event days and loss of supply, at the end of 2031.	Five-Year	Target (End of 2031): 1.49 – 1.52
		SAIFI (#) This measure reports the system average interruption frequency index (SAIFI), excluding major event days and loss of supply, at the end of 2031.	Five-Year	Target (End of 2031): 1.14 – 1.16
		FESI-7 (%)	Five-Year	Report the FESI-7 results (%) at the end of 2031

Performance Outcomes	Performance Categories	Metrics	Target	Notes
		This measure reports the percentage of distribution feeders on Elexicon's system that have experienced more than 7 sustained interruptions per calendar year at the end of 2031.		Target (End of 2031): ≤ 10%
	Asset Management	Incremental Station Supply Capacity (MVA)	Five-year	Report the station supply capacity added by end of 2031.
		This measure reports the increased station supply capacity to meet the increased demand by end of 2031.		Target (End of 2031): 180 MVA
		Incremental Distribution System Capacity (MVA)	Five-year	Report the distribution system capacity added by end of 2031.
		This measure reports the increased distribution system capacity to meet the increased demand by end of 2031.		Target (End of 2031): 101 MVA
		# of Stations with Limited Capacity (0 – 1,000 kVA)	Five-year	Report the number of stations with limited capacity by end of 2031.
		This metric reports the number of municipal stations with limited capacity within Elexicon's service territory (0 – 1,000 kVA) by end of 2031.		Target (End of 2031): 21 stations
		Asset Condition Assessment (%)	Monitor	Report the ACA results (%) of assets in poor or very poor condition annually.
		This measure reports the percentage of distribution and substation assets in Elexicon's service territory in poor or very poor condition.		
		Distribution Assets Exceeding or Approaching Typical Useful Life (%)	Five-year	Report the End of 2031 results of the Distribution Assets Typical Useful Life (%) against Elexicon set target.

Performance Outcomes	Performance Categories	Metrics	Target	Notes
		This measure reports the projected percentage of distribution assets in Elexicon's service territory that have exceeded or will exceed TUL within 5 years by the end of 2031.		Target (End of 2031): ≤ 28%
		Substation Assets Exceeding or Approaching Typical Useful Life (%)	Five-year	Report the End of 2031 results of the Substation Assets Typical Useful Life (%) against Elexicon set target.
		This measure reports the projected percentage of substation assets in Elexicon's service territory that have exceeded or will exceed TUL within 5 years by the end of 2031.		Target (End of 2031): ≤ 32%
Financial Performance	Cost Control	Vegetation Management – Planned ($/km)	Monitor	Report the planned vegetation management costs ($) annually.
		This measure reports the cost of the planned vegetation management program located near overhead feeders per kilometre trimmed.		

1.2.1 SAIDI:

This metric targets the projected System Average Interruption Duration Index (SAIDI), excluding major event days (MED) and loss of supply (LOS), by the end of 2031 within a specified range. See Table 4 below.

SAIDI has been steadily increasing in recent years, and Elexicon has exceeded the OEB target for SAIDI (1.35) in four of the previous five years (2020, 2022, 2023, and 2024). As documented within Section 1.2 of this Schedule and described throughout the System Renewal investment narratives (Exhibit 2B – Tab 4 – Schedule 3 – Appendices E-H), reliability performance at Elexicon in recent years has been challenged due to investment constraints that have impacted the pace of planned asset renewals. As a result, the age of select assets have been increasing beyond their Typical Useful Life and the condition of the select assets has declined to Poor or Very Poor condition, which negatively impact SAIDI performance results.

With the planned capital and maintenance investments in the 2027-2031 DSP period, Elexicon forecasts an improvement in SAIDI results at the end of 2031 when compared to recent 2021-2025 SAIDI averages. A more recent 5-year range of SAIDI averages were selected as a baseline due to Elexicon's declining SAIDI performance, as noted above, and the historical 2020-2024 period is not reflective of the current asset and reliability state. Table 3 below shows the 2021-2025 SAIDI values and the associated 5-Year average.

Table 3: 2021 to 2025 SAIDI Values

Metric	**2021**	**2022**	**2023**	**2024**	**2025**[1]	5-Year Average
SAIDI	1.17	1.71	1.37	1.71	1.77	1.55

The 2021-2025 SAIDI average of 1.55 was used as the 2027 baseline. Annual performance targets for SAIDI have been set between the range of 0.25% - 0.50% and are applied sequentially, producing the end of 2031 target results in Table 4 below.

Table 4: SAIDI (Excluding MED and LOS), End of 2031 Target

Performance Measure	5-Year Average (2021-2025)	Target (End of 2031)
SAIDI (Excluding MED and LOS)	1.55 hrs	1.49 – 1.52

1.2.2 SAIFI:

This metric targets the projected System Average Interruption Frequency Index (SAIFI), excluding major event days (MED) and loss of supply (LOS), by the end of 2031 within a specified range. See Table 6 below.

SAIFI remained relatively stable from 2020 to 2024, and Elexicon performed below the SAIFI target (1.69) in each of those five years. As documented within Section 1.2 of this Schedule and described throughout the System Renewal investment narratives (Exhibit 2B – Tab 4 – Schedule 3 – Appendices E-H), reliability performance at Elexicon in recent years has been challenged due to investment constraints that have impacted the pace of planned asset renewals. As a result, the age of select assets have been increasing

[1] 2025 figures represent a forecast based on actual results through October 2025

beyond Typical Useful Life and the condition of the select assets has declined to Poor or Very Poor condition, which impact SAIFI performance results.

With the planned capital and maintenance investments in the 2027-2031 DSP period, Elexicon forecasts SAIFI results to be relatively consistent by the end of 2031 when compared to recent 2021-2025 SAIFI averages. A more recent range of SAIFI averages were selected as a baseline due to Elexicon's recently declining SAIFI performance as noted above, and the historical 2020-2024 period is not reflective of the current asset and reliability state. Table 5 shows the 2021-2025 SAIFI values and the associated 5-Year average.

Table 5: 2021 to 2025 SAIFI Values

Metric	**2021**	**2022**	**2023**	**2024**	**2025**	5-Year Average
SAIFI	1.12	1.19	0.97	1.16	1.36	1.16

The 2021-2025 SAIFI average of 1.16 was used as the 2027 baseline. Annual performance targets for SAIFI have been set between the range of 0% - 0.25% and are applied sequentially, producing the end of 2031 target results in Table 6 below.

Table 6: SAIFI (Excluding MED and LOS), End of 2031 Target

Performance Measure	5-Year Average (2021-2025)	Target (End of 2031)
SAIFI (Excluding MED and LOS)	1.16	1.14 – 1.16

1.2.3 FESI-7:

This metric measures the percentage of distribution feeders that experience more than seven sustained interruptions in a calendar year, excluding MED, LOS, and scheduled outages (SO). The target Elexicon has set by the end of 2031 is 10% or less. Elexicon currently has approximately 256 feeders, which corresponds to no more than 25 feeders exceeding the target. It should be noted that additional feeders are planned to be constructed during the 2027-2031 period and the target value is proportional to the total number of feeders. FESI-7 is a key reliability metric actively used at Elexicon to help drive targeted investments in inspection, maintenance, and capital programs for underperforming feeders, supporting improved reliability and customer satisfaction.

Table 7: FESI-7 (Excluding MED, SO, and LOS), End of 2031 Target

Performance Measure	Target (End of 2031)
FESI-7 (Excluding MED, SO and LOS)	≤ 10%

Based 2020-2024 results in Table 8, Elexicon has exceeded the proposed 10% target in 4 of the previous 5 years, with 2025 projecting even further decline. These performance results underscore the need for the planned capital and maintenance investments to improve future year performance results.

Table 8: Historical FESI-7 results (2020–2024), by number of feeders

Performance Measure	**2020**	**2021**	**2022**	**2023**	**2024**
FESI-7 (Excluding MED, SO and LOS)	33	33	27	15	26

1.2.4 Incremental Station Supply Capacity:

Elexicon plans to increase its station supply capacity to meet growing customer load demand and ensure reliable service. This capacity increase is critical to support community growth and enable new customer connections. By the end of 2031, Elexicon targets an additional 180 MVA of station supply capacity, a 14% increase compared to current levels, driven by the completion of the new GTA East Transformer Station. Refer to the Substation Growth program (Exhibit 2B – Tab 4 – Schedule 3 – Appendix I) for more details.

Table 9: Incremental Station Supply Capacity (MVA), End of 2031 Target

Performance Measure	Target (End of 2031)
Incremental Station Supply Capacity (MVA)	180 MVA

1.2.5 Incremental Distribution System Capacity:

Elexicon plans to increase its distribution system capacity to meet growing customer load demand and ensure reliable service. This capacity increase is critical to support community growth and enable new customer connections. By the end of 2031, Elexicon targets an additional 101 MVA of distribution system capacity, a 12% increase compared to current levels. Refer to the Substation Growth program and Substation Renewal program for more details.

Table 10: Incremental Distribution System Capacity (MVA), End of 2031 Target

Performance Measure	Target (End of 2031)

Incremental Distribution System Capacity (MVA)	101 MVA

1.2.6 Stations with Limited Capacity (0 – 1,000 kVA):

This metric reports the number of stations with limited capacity within Elexicon's service territory. The end of 2031 target is 21 stations. The projection is based on current capacity constraints and incorporates planned substation capital investments over the application period. The capacity range is aligned with the ranges on Elexicon's Distribution System Capacity Information Map.

Currently, 44 stations have limited capacity (0 -1000 kVA), and without further investment, load growth would result in an additional three stations reaching this status by the end of 2031, to a total of 47 stations with limited capacity. Further details on this are outlined in Exhibit 2B - Tab 3 - Schedule 3. With the planned investments, Elexicon projects that the number of stations with limited capacity will decrease to 21 by the end of 2031, with most of the reduction occurring toward 2031 given the investment timing.

Table 11: Stations with Limited Capacity (0 – 1,000 kVA), End of 2031 Target

Performance Measure	Current (2025)	Target (End of 2031)
Station with Limited Capacity (0 - 1,000 kVA)	44	21

1.2.7 Asset Condition Assessment:

This metric reports the percentage of distribution and station assets in Elexicon's service territory that are in poor or very poor condition. Results are derived from the annual ACA and aggregate all assets classified as poor or very poor across distribution and substation categories. Based on the 2025 ACA, approximately 11.5% of Elexicon's total distribution system assets are in poor or very poor condition. Elexicon will monitor the annual percentage of total distribution system assets in poor or very poor condition and adjust investment plans as needed to ensure accountability and effective execution of the system renewal program.

Figure 1: Asset Health Index (HI) – System Assets Current State (2025)

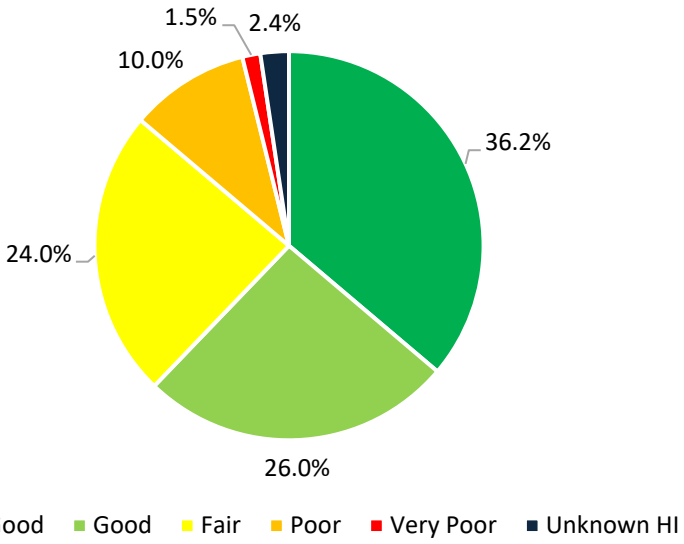


Table 12: Asset Condition Assessment, Monitor Annually

Performance Measure	Annual
Asset Condition Assessment (Total Distribution System % Poor or Very Poor Assets)	Monitor

1.2.8 Distribution Assets Exceeding or Approaching Typical Useful Life:

This metric reports the projected percentage of distribution assets in Elexicon's service territory that have exceeded or are expected to exceed their typical useful life within five years. The end of 2031 target is ≤ 28%. The projection uses age-based demographic data across distribution asset categories and incorporates the planned investments outlined in the 2027-2031 DSP period. Based on the 2025 assessment, approximately 21.7% of distribution assets have reached or will reach their typical useful life within five years. With the planned DSP investments, this proportion is projected to rise to approximately 28% by the end of 2031. Elexicon will monitor these results annually to ensure effective execution of the system renewal program.

Figure 2: Age Demographics – Distribution Assets Current State (2025)

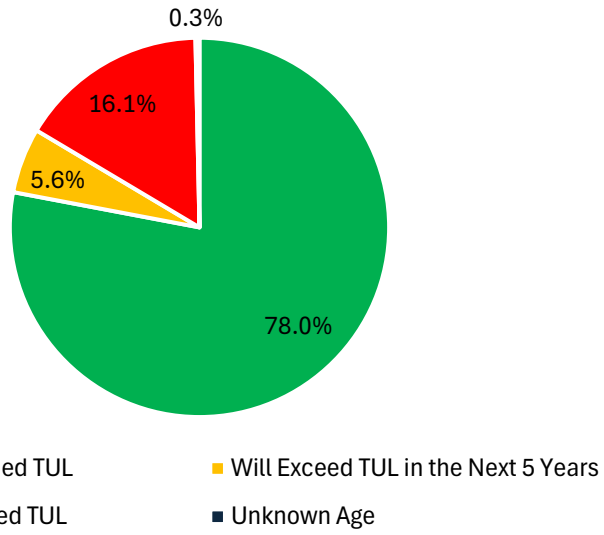


Figure 3: Balanced Investment Option Age Demographics at 2031 – Distribution Assets

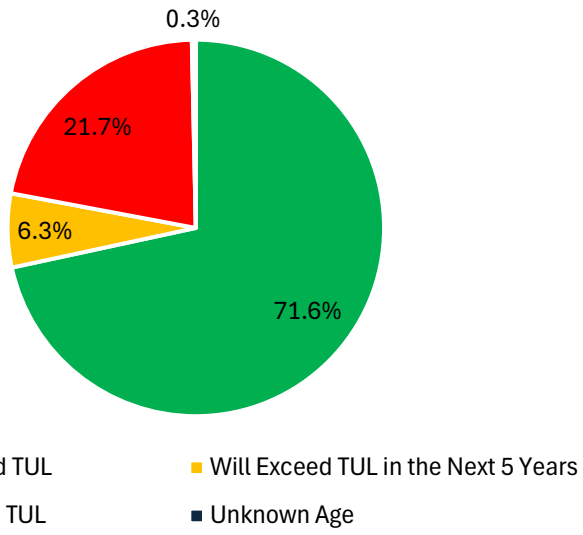


Table 13: Distribution Assets Exceeding or Approaching TUL, End of 2031 Target

Performance Measure	Target (End of 2031)
Distribution Assets Exceeding or Approaching TUL	≤ 28%

1.2.9 Substation Assets Exceeding or Approaching Typical Useful Life:

This metric reports the projected percentage of station assets in Elexicon's service territory that have exceeded or are expected to exceed their typical useful life within five years. The end of 2031 target is ≤ 32%. The projection uses age-based demographic data across station asset categories and incorporates the planned investments outlined in the 2027-2031 DSP period. Based on the 2025 assessment, approximately 28.4% of substation assets have reached or will reach their typical useful life within five years. With the planned DSP investments, this proportion is projected to rise to approximately 31.6% by the end of 2031. Elexicon will monitor these results annually to ensure effective execution of the system renewal program.

Figure 4: Age Demographics – Station Assets Current State (2025)

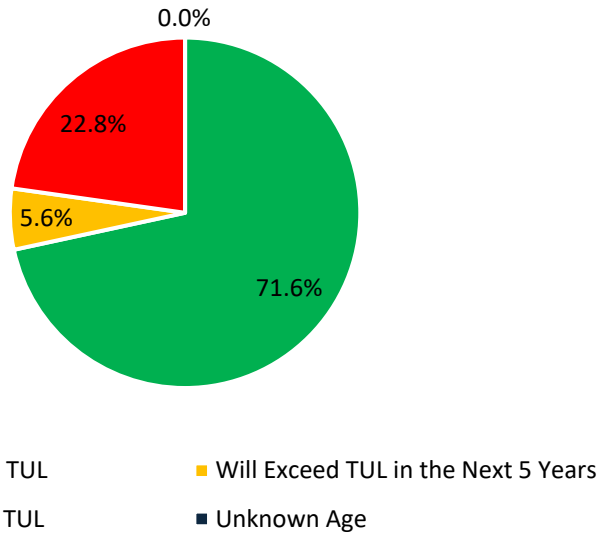


Figure 5: Balanced Investment Option Age Demographics at 2031 – Station Assets

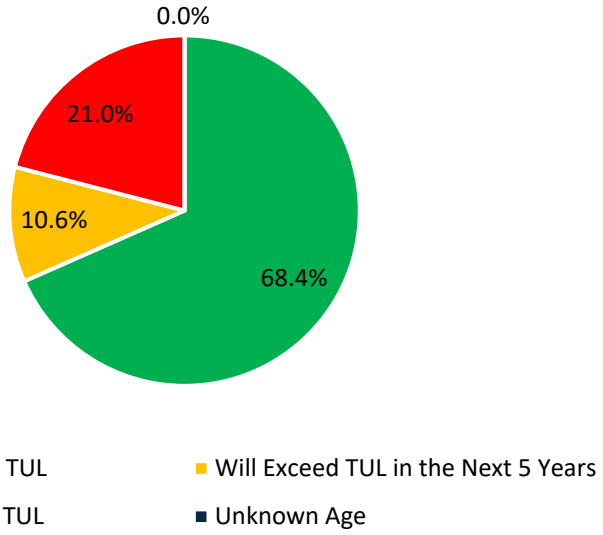


Table 14: Substation Assets Exceeding or Approaching TUL, End of 2031 Target

Performance Measure	Target (End of 2031)
Substation Assets Exceeding or Approaching TUL	≤ 32%

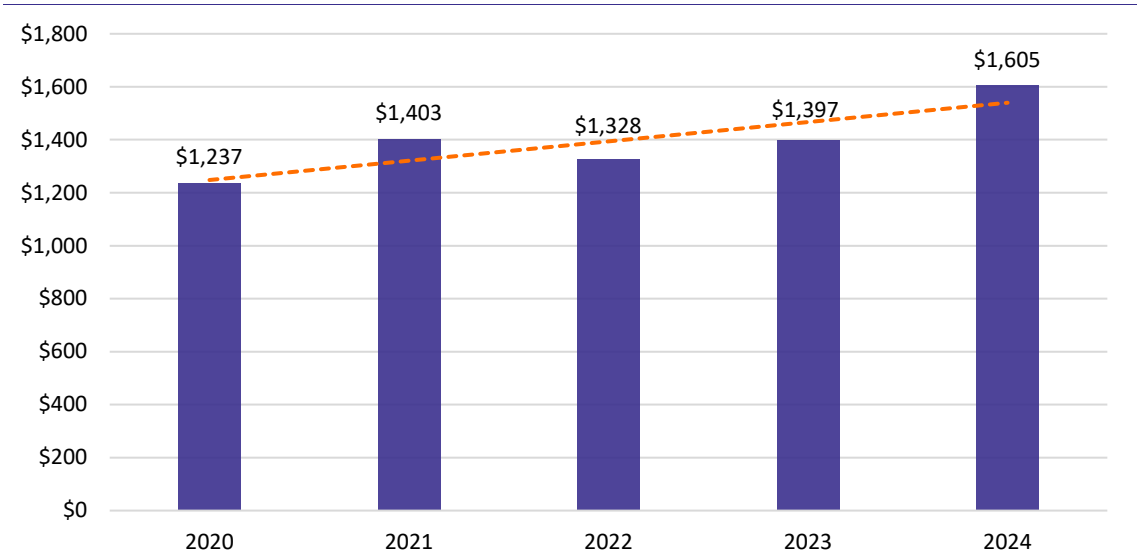
1.2.10 Vegetation Management:

This metric reports the cost of the planned vegetation management program for overhead feeders per kilometre trimmed. Annual program costs are monitored to ensure effective management and accountability. The measure excludes spot trimming requests and aggregates total planned vegetation management costs and kilometres of line trimmed. Between 2020 and 2024, overall program costs increased by an average of 3.5% per year. Elexicon will monitor annual program costs to ensure accountability and to achieve cost efficiencies through continuous improvement initiatives such as LIDAR scanning, and AI-enabled analytics. See the Sustainment OM&A Exhibit for further details on vegetation management (Exhibit 4 - Tab 1 - Schedule 4).

Table 15: Vegetation Management – Planned ($/km), Monitor Annually

Performance Measure	Annual
Vegetation Management – Planned ($/km)	Monitor

Figure 6: Vegetation Trimming cost per Circuit km (2020–2024)



1.3 Service Quality and Reliability

Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. Elexicon strives to deliver customer excellence and value through the execution of its investments and operations. Elexicon tracks and reports the Service Quality Requirements (SQR) outlined in Chapter 7 of the OEB's Distribution System Code (DSC). These metrics generally reflect the day-to-day performance of direct contact with customers and are dependent upon DSP process performance. Reporting of performance measures follows the OEB's Electricity Reporting & Recordkeeping Requirements for Electricity Distributors, where applicable, using their standard definitions laid out in that document.[2]

[2] Ontario Energy Board, "Electricity Reporting & Recordkeeping Requirements" (Updated March 14, 2025)

Elexicon has filed a completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, as Exhibit 1, Tab 6, Schedule 2 – Attachment 2.

Elexicon's service quality and reliability are detailed further in the following subsections.

1.3.1 Service Quality Requirements

Elexicon's SQR performance for the historical period is summarized in Table 16. A review of Elexicon's Service Quality Requirements (SQR) performance from 2020 to 2024 demonstrates that Elexicon consistently met or exceeded the OEBs minimum standards across all measured metrics, with the exception of Telephone Accessibility in 2020 (Refer to Section 1.1 of this Schedule) and Rescheduling a Missed Appointment between 2020 and 2022.

Table 16: Historical Service Quality Metrics

Service Quality Metric	**2020**	**2021**	**2022**	**2023**	**2024**	Minimum Standards
Low Voltage Connections	93.74%	95.97%	96.94%	98.57%	98.77%	> 90%
High Voltage Connections	100%	100%	100%	100%	100%	> 90%
Telephone accessibility	61.89%	75.99%	76.06%	72.35%	75.90%	> 65%
Appointments met	98.80%	99.96%	98.01%	99.12%	99.45%	> 90%
Written response to enquiries	97.33%	99.00%	99.60%	97.93%	98.82%	> 80%
Emergency Urban Response	100%	100%	100%	81.73%	93.02%	> 80%
Emergency Rural Response	100%	100%	N/A	89.47%	91.18%	> 80%
Telephone call abandon rate	4.85%	2.11%	2.63%	4.04%	3.32%	< 10%
Appointment scheduling	91.07%	99.86%	98.29%	99.28%	99.67%	> 90%
Rescheduling a Missed Appointment	99.88%	75%	95.18%	100%	100%	100%
Reconnection Performance Standard	100%	100%	100%	100%	100%	> 85%
New Micro-embedded Generation Facilities Connected	100%	100%	100%	100%	100%	> 90%
Billing Accuracy	99.60%	99.75%	99.82%	99.87%	99.91%	> 98%

Elexicon experienced below-target performance on the Rescheduling a Missed Appointment metric between 2020 and 2022. In 2020, Elexicon achieved 99.88%, narrowly missing the 100% target. In 2021, performance dropped to 75%, largely due to scheduling backlogs and difficulties coordinating with customers during the height of the pandemic. Although performance improved to 95.18% in 2022, the

target was still not met. In response, Elexicon strengthened its internal coordination and follow-up processes, implemented improved scheduling tools, and provided staff training to support timely rescheduling of missed appointments. As a result, Elexicon successfully achieved 100% compliance in 2023 and 2024, demonstrating the effectiveness of its corrective measures.

1.3.2 Reliability Requirements

System reliability is an indicator of the quality of electricity service delivered to the customer. Elexicon monitors system reliability and performance through a variety of reports generated by its Outage Management System (OMS). System reliability events and results are identified and investigated, facilitating the identification of targeted maintenance and/or required capital investments.

The key metrics that Elexicon tracks to measure reliability are SAIDI, SAIFI, Customer Average Interruption Duration Index (CAIDI) and Feeders Experiencing More than Seven Sustained Interruptions (FESI-7). FESI-7 is measured excluding LOS, MED and Scheduled Outages. Whereas SAIDI, SAIFI and CAIDI are measured under three scenarios:

1. By including all power interruptions
2. By excluding interruptions due to Loss of Supply (LOS)
3. By excluding interruptions due to LOS and Major Event Days (MED)

In addition, the root cause of power interruptions are monitored and analyzed. Each power interruption that occurs on Elexicon's distribution system is recorded and an interruption cause code is assigned. The number of customer interruption hours for each cause code provides meaningful insights into the sources of outages within Elexicon's system, this data is mined for targeted investment planning purposes.

These metrics enable Elexicon to track performance relative to its asset management objectives of:

- Ensuring the distribution system provides a sustainable and reliable service to customers; and
- Reducing the number of poor performing and aging assets with prioritized investments to improve reliability, resiliency, and simultaneously modernize the grid.

There are certain events which, although they negatively impact reliability, are beyond the control of utilities. As such, Elexicon's SAIDI and SAIFI performance metrics exclude the following:

- LOS interruptions, which occur due to problems associated with assets owned by a party other than Elexicon or the bulk electricity supply system; and
- Force majeure or catastrophic event days measured using an industry standard Major Event Day (MED) methodology. An MED is a day in which the daily SAIDI exceeds an MED threshold value.

Major Event Days are identified using the IEEE Standard 1366 Beta Method, which provides a consistent and industry recognized method for determining days when extreme or unusual events significantly impact system reliability. Under this standard, a statistical threshold is calculated based on Elexicon's daily SAIDI performance over the past five years. If the daily SAIDI exceeds this threshold, the day is classified as a Major Event Day. Elexicon follows this methodology to ensure that only exceptional, uncontrollable events such as extreme weather or large-scale external system failures are excluded from regular reliability reporting. This allows for a more accurate assessment of the utility's day-to-day performance and the effectiveness of its asset management practices.

Elexicon's reliability metric values for the historical period are shown in the tables and figures below.

Table 17: Historical Reliability Performance Metrics – All Cause Codes

Metric	**2020**	**2021**	**2022**	**2023**	**2024**	Average
SAIDI	3.33	2.16	22.65	2.15	3.78	6.81
SAIFI	1.74	1.92	2.90	1.45	1.67	1.94
CAIDI	1.92	1.12	7.80	1.48	2.26	2.92

Table 18: Historical Reliability Performance Metrics – LOS and MED Adjusted

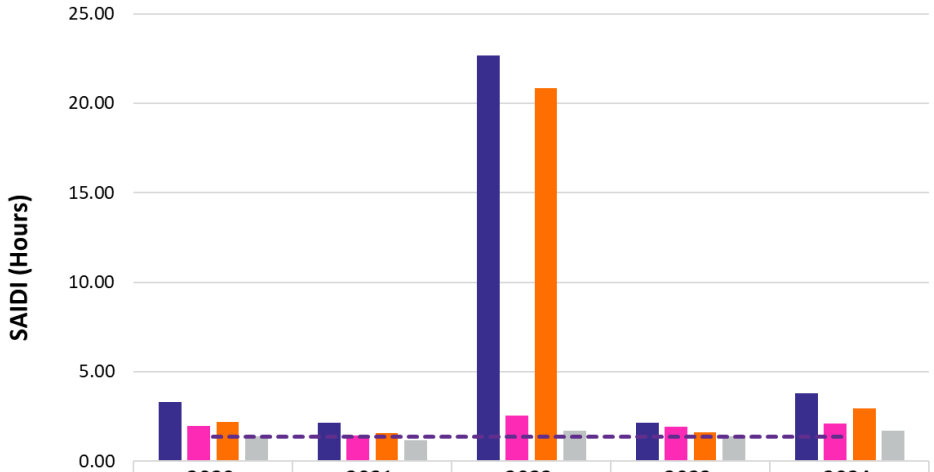
Metric	**2020**	**2021**	**2022**	**2023**	**2024**	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)					
SAIDI	2.22	1.58	20.82	1.60	2.94	5.83
SAIFI	1.17	1.26	2.22	1.04	1.18	1.37
CAIDI	1.90	1.26	9.37	1.54	2.49	3.31
	Major Event Days Adjusted (including LOS, excluding MEDs)					
SAIDI	1.97	1.42	2.55	1.92	2.10	1.99
SAIFI	1.42	1.52	1.69	1.37	1.62	1.52
CAIDI	1.38	0.93	1.51	1.40	1.29	1.30

Metric	2020	2021	2022	2023	2024	Average
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)					
SAIDI	1.37	1.17	1.71	1.37	1.71	1.47
SAIFI	1.01	1.12	1.19	0.97	1.16	1.09
CAIDI	1.35	1.05	1.44	1.42	1.47	1.35

1.3.3 SAIDI Performance

Elexicon evaluates SAIDI performance by excluding MEDs and LOS to analyze the system without circumstances beyond Elexicon's control. Over the past 5 years, Elexicon's SAIDI performance is on a decline and exceeded the OEB target of 1.35 hrs in 2020, 2022, 2023 and 2024 as illustrated in Figure 7. The top three contributors to the decline in SAIDI results during this period are defective equipment (30%), Tree contacts (20%) and foreign interference (14%) primarily due to animal contacts.

Figure 7: Performance Measure – SAIDI



	2020	2021	2022	2023	2024
SAIDI	3.32	2.16	22.65	2.14	3.78
SAIDI LOS adjusted	1.97	1.42	2.55	1.92	2.10
SAIDI MED adjusted	2.21	1.58	20.85	1.60	2.93
SAIDI MED & LOS Adjusted	1.37	1.17	1.71	1.37	1.71
Elexicon SAIDI Target	1.35	1.35	1.35	1.35	1.35

In 2020, the result was impacted by a major outage as result of equipment failure, which accounted for approximately 22% of the year's total outage duration. In 2022, SAIDI performance was affected by several severe weather events and station equipment failures. Although some of the storms were significant, they did not meet the OEB's threshold for classification as MEDs and were therefore included in reported reliability metrics. In 2022, adverse weather events resulted in 59,124 CHI, excluding MEDs. These were isolated events that impacted Elexicon's service areas, including Ajax, Pickering, Belleville, and Gravenhurst, with the most significant events taking place in the months of June, October and December. These events were a result of heavy rains, snow and high winds resulting in unplanned outages. In 2023, SAIDI remained slightly above target despite noticeable improvement over the prior year. This was due to continued strain on the system from aging infrastructure. In 2024, continued equipment failures, severe weather events, tree contacts and foreign interference resulted in SAIDI results similar to 2022.

Elexicon continues to face challenges related to its aging and deteriorating distribution infrastructure, which has led to significant distribution and substation equipment failures that resulted in prolonged outages during the historical period. Currently, 14% of substation assets and 13% of distribution assets are in poor or very poor condition and require intervention. To address this, capital investments are prioritized to address aging and deteriorating overhead assets, underground cables, and substation equipment. Further details are outlined in the System Renewal Material Narratives presented in Exhibit 2B - Tab 4 - Schedule 3 - Appendices E-H.

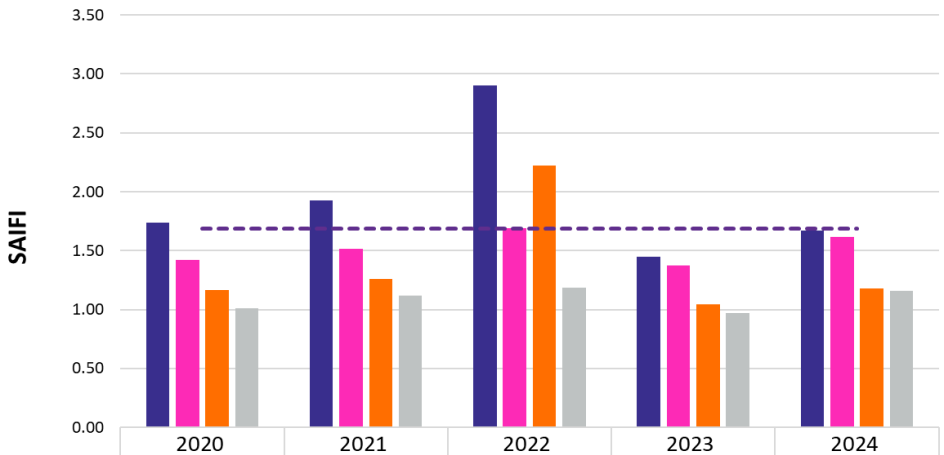
Additionally, Elexicon's non-contiguous service territory spanning both rural and urban areas presents unique vegetation management challenges. For further details, refer to the Vegetation Management segment in Exhibit 4 - Tab 1 - Schedule 4. Rural areas such as Gravenhurst, which are more prone to tree contacts, require more frequent tree trimming to maintain reliability. To mitigate the impact of the tree contact outages, Elexicon is enhancing its vegetation management strategy and introducing technologies such as satellite imagery and artificial intelligence to identify tree encroachments in high-risk zones, which will enable the development of optimized feeder trimming cycles. In addition, Elexicon is continuing proactive inspections, pole testing, and maintenance practices designed to identify at-risk assets before failure occurs. Elexicon is also advancing grid modernization strategy to improve outage detection and

restoration through Fault Location, Isolation, and Service Restoration (FLISR) capabilities. Further details are captured in Grid Enhancements Material Narrative (Exhibit 2B - Tab 4 - Schedule 3 – Appendix J). These investments are expected to improve SAIDI performance, reduce outage durations, and enhance overall system resilience as Elexicon prepares for increasing system demands and future growth.

1.3.4 SAIFI Performance

Like SAIDI, Elexicon evaluates SAIFI performance by excluding MEDs and LOS to analyze the system without circumstances beyond Elexicon's Control. Elexicon's historical SAIFI performance consistently met reliability targets from 2020 to 2024 as illustrated in Figure 8, reflecting Elexicon's strong ability to limit the number of interruptions experienced by customers under normal operating conditions.

Figure 8: Performance Measure – SAIFI



	2020	2021	2022	2023	2024
SAIFI	1.74	1.92	2.90	1.45	1.67
SAIFI LOS Adjusted	1.42	1.52	1.69	1.37	1.62
SAIFI MED Adjusted	1.17	1.26	2.22	1.04	1.18
SAIFI MED & LOS Adjusted	1.01	1.12	1.19	0.97	1.16
Elexicon SAIFI Target	1.69	1.69	1.69	1.69	1.69

The top three contributors to SAIFI during the historical period are Unknowns (28%), Defective Equipment (27%) and Tree Contacts (15%). Elexicon's SAIFI performance has been attributed to feeder redundancy planning, improvements to feeder protection coordination, feeder reconfigurations to reduce customer

impact, outage management process improvements, and previous investments made in SCADA enabled devices.

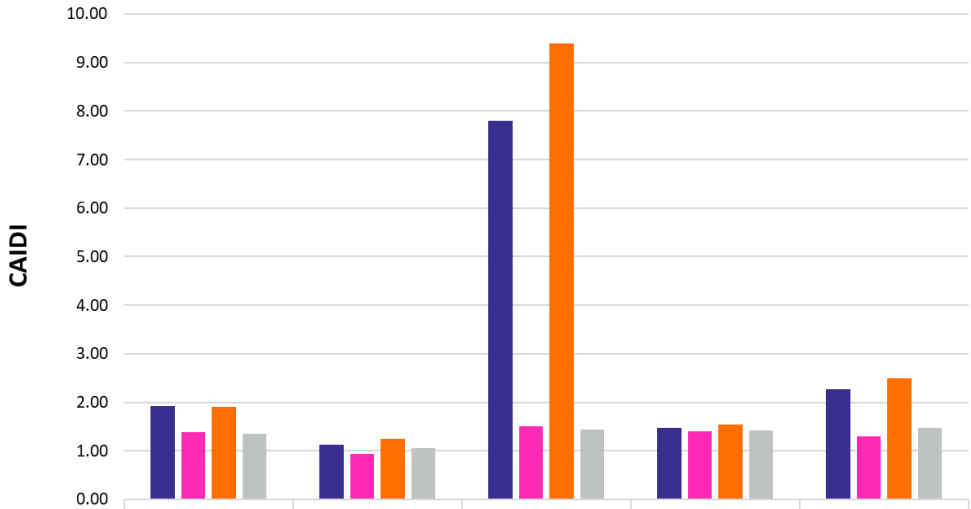
To sustain SAIFI performance, Elexicon is investing in the replacement of assets that are at high risk of failure. Further details are outlined in the System Renewal Material Narratives presented in Exhibit 2B - Tab 4 - Schedule 3 - Appendices E-H. In addition, Elexicon is investing Grid Modernization technologies for fault location and sectionalizing to minimize the number of customers affected during outages. Further details are captured in Grid Enhancements Material Narrative (Exhibit 2B - Tab 4 - Schedule 3 – Appendix J). These technologies will also aid in root cause identification of unknown outages. Elexicon is also enhancing system resiliency by constructing additional feeders and stations in high-risk areas. Furthermore, Elexicon is strengthening its vegetation management program to mitigate reliability risks, particularly in regions prone to tree-related outages.

1.3.5 CAIDI Performance

Elexicon monitors CAIDI performance internally to assess outage restoration and response times. As illustrated in Figure 9, the average customer interruption duration has been trending upward. This trend is primarily attributed to a rise in SAIDI, while SAIFI has remained relatively stable over the historical period. The deterioration in CAIDI is largely driven by an increase in adverse weather events, tree contacts, equipment failures, and foreign interference, including major vehicle accidents and animal contacts.

Elexicon's non-contiguous service territory, spanning both rural and urban zones, presents operational challenges. Outages in rural areas generally take longer to restore due to accessibility issues and safety considerations particularly during nighttime or severe weather conditions. Additionally, the growing number of major equipment failures, largely due to aging infrastructure and major tree contacts along with limited automation has contributed to the decline in CAIDI performance.

Figure 9: Performance Measure – CAIDI



	2020	2021	2022	2023	2024
CAIDI	1.92	1.12	7.80	1.48	2.26
CAIDI LOS Adjusted	1.38	0.93	1.51	1.40	1.29
CAIDI MED Adjusted	1.90	1.25	9.39	1.54	2.49
CAIDI MED & LOS Adjusted	1.35	1.05	1.44	1.42	1.47

To address these challenges, Elexicon is investing in Grid Modernization technologies to enhance outage response and restoration capabilities. These technologies support SCADA-Enabled Switches & Reclosers, Communicating Fault Circuit Indicators (CFCIs), Self-Resetting Fuses, Station Modernization, Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI 2.0) and are being deployed through System Service investments. Further details are captured in Grid Enhancements Material Narrative (Exhibit 2B - Tab 4 - Schedule 3 - Appendix J).

1.3.6 FESI-7

Elexicon utilizes the Feeders Experiencing More than 7 Sustained Interruptions (FESI-7) metric to identify and monitor its Worst Performing Feeders (WPFs). This performance metric excludes LOS, MEDs, and scheduled outages (SO) to provide a more accurate representation of underlying reliability issues that are within Elexicon's control. Table 19 outlined below shows the number of FESI-7 over the past 5 years.

Table 19: Historical FESI-7 Performance (2020–2024)

Metric	2020	2021	2022	2023	2024
FESI-7	33	33	27	15	26

In addition to tracking sustained interruptions, Elexicon also considers customer impact and outage duration when prioritizing targeted investments on its top 10 WPFs by SAIDI. Elexicon regularly monitors its WPFs and directs investments to improve their performance. Asset renewal investments are prioritized on these feeders, focusing on the replacement of aging infrastructure that poses a high risk of failure.

Furthermore, investments are also concentrated on WPFs, including the deployment of:

- SCADA-enabled devices for enhanced monitoring and control,
- Smart fault circuit indicators to improve fault detection and restoration,
- Animal guards and lightning arrestors to reduce outages caused by wildlife and transient overvoltage's caused by lightning

Further details encompassing the above investments are outlined in the following Material Narratives:

- Substation Renewal (Exhibit 2B - Tab 4 - Schedule 3 - Appendix E)
- Underground System Renewal (Exhibit 2B - Tab 4 - Schedule 3 - Appendix F)
- Overhead System Renewal (Exhibit 2B - Tab 4 - Schedule 3 - Appendix G)
- Grid Enhancements (Exhibit 2B - Tab 4 - Schedule 3 - Appendix J)

2. OUTAGE DETAILS FOR YEARS 2020-2024

2.1 Major Events

Between 2020 and 2024, Elexicon Energy systematically tracked service interruptions in alignment with the Ontario Energy Board's (OEB) Reporting and Record Keeping Requirements (RRRs). All interruptions were categorized using the primary cause codes prescribed by the OEB to ensure consistency and regulatory compliance. This section provides a comprehensive summary and analysis of Major Event Days

(MEDs) as defined by the OEB, Interruption causes classified by standardized cause codes, and the resulting reliability metrics, specifically Customer Interruptions (CI), and Customer Hours of Interruption (CHI). The data presented herein supports Elexicon's ongoing commitment to transparency, reliability performance monitoring, and continuous improvement in service delivery.

Table 20: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2020	4	Adverse weather – wind and thunderstorms
2021	2	Adverse weather – wind and thunderstorms / Loss of supply
2022	4	Adverse weather – wind and thunderstorms / Loss of supply
2023	1	Adverse Weather – Snow and wind
2024	1	Adverse Weather – Snow and Wind

Table 21: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
January 25, 2020	18,071	**Loss of Supply:** The Major Event was due to a Loss of Supply from Hydro One. On short notice, Hydro One was required to conduct emergency repair work to replace damaged equipment at Belleville Transmission Station which serves Hydro One customers along with Elexicon Energy customers in Belleville and the surrounding area. Due to the location of the damaged equipment, the station had to be de-energized while crews completed the critical work. The work was completed in advance of a winter storm that was anticipated in order to eliminate the risk of further damage and a more prolonged outage.
July 19, 2020	17,989	**Adverse Weather – Wind:** Elexicon Energy experienced high winds and rain in a number of areas it services. Tree contacts with conductors produced a number of customer outages or resulted in loss of supply for Elexicon customers.

Date	Customer Base Interrupted	Description
October 23, 2020	2,614	**Adverse Weather – Wind and Thunderstorms:** A fast-moving line of severe thunderstorms produced damaging wind gusts, lightning, and tree contacts with equipment, resulting in customer outages.
November 15, 2020	22,892	**Adverse Weather – Wind and Thunderstorms:** High winds caused outages likely due to trees or debris hitting lines.
May 26, 2021	38,055	**Loss of Supply:** Hydro One lost one of their transmission circuits, T24C, feeding Thornton TS and part of Whitby TS. At the time of that circuit outage, the backup transmission circuit for these facilities, T26C, was out of service for planned work. As a result, Elexicon customers supplied from those facilities lost power.
December 11, 2021	30,471	**Adverse Weather – Wind:** Windstorm
May 21, 2022	126,456	**Adverse Weather – Wind:** A derecho storm swept through the province of Ontario and large portions of Elexicon's service territory. This widespread and fast-moving storm caused extensive damage to Elexicon's infrastructure thereby leading to prolonged power outages for the majority of Elexicon's customers.
June 16, 2022	22,549	**Loss of Supply:** Another main contributing cause is the: Adverse Weather-Wind A severe thunderstorm passed through the region of Belleville, resulting in downed trees and conductors. Hydro One lost two feeders during the storm which supplied Elexicon stations. As a result, Elexicon customers supplied from those facilities lost power. After Hydro One restored power, downed trees on Elexicon lines further hindered restoration efforts.
December 3, 2022	9,727	**Adverse Weather – Wind:** A high winds event caused a loss of supply to our Newcastle customer base. Given that the impacted device was an asset owned by Hydro One Networks Inc., Elexicon Energy had limited control in restoring customers in a more timely manner.

Date	Customer Base Interrupted	Description
December 23, 2022	52,334	**Adverse Weather – Wind and Snow:** Wind An historic winter storm including blizzards, high winds and snowfall swept through the region from December 23rd to 25th causing widespread outages. High winds brought down trees and power lines resulting in damage to critical infrastructure.
January 25, 2023	13,330	**Adverse Weather – Snow:** A snowstorm swept through the region with winds gusts and heavy snowfall resulting in power outages. Heavy snow fall accumulation between 15 to 20cm during rush hour traffic. The timing of the storm complicated matters. Unplowed roads at rush hour traffic restricted the movement of crews and our ability to restore customers.
November 29, 2024	8,879	**Adverse Weather – Snow:** On November 29, 2024, a severe winter storm struck the Gravenhurst area, bringing heavy snowfall, strong winds, and blizzard conditions. The storm resulted in road closures (including Highway 11 for several days), abandoned vehicles, downed trees, accidents, and widespread power outages. In response to the crisis, the town of Gravenhurst declared a state of emergency.

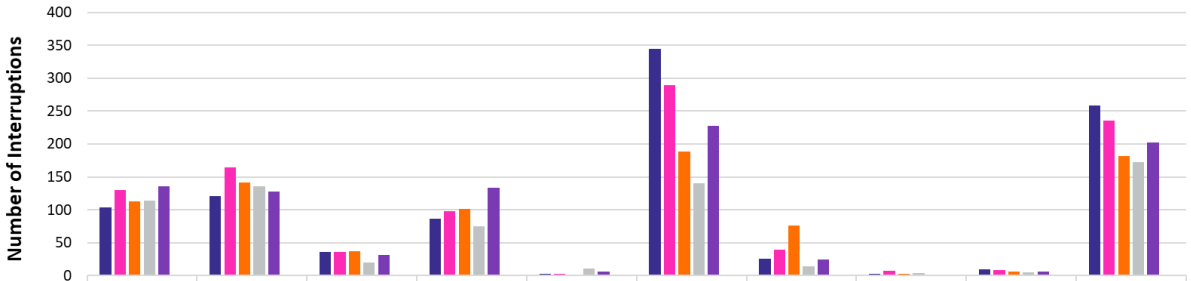
2.2 Interruptions Experienced

Table 22 and Figure 10 below presents the count of interruptions broken down by cause code for the historical period. The number of interruptions reflects outage frequency and affects customers differently based on customer class.

Table 22: Outage Numbers by Cause Codes – Excluding MEDs

Cause Code	2020	2021	2022	2023	2024	Total Outages	%
0-Unknown/Other	104	130	113	114	136	597	13.4%
1-Scheduled Outage	121	164	141	136	128	690	15.5%
2-Loss of Supply	36	36	37	20	32	161	3.6%
3-Tree Contacts	87	98	101	75	134	495	11.1%
4-Lightning	3	3	2	11	6	25	0.6%
5-Defective Equipment	344	290	189	140	228	1191	26.8%
6-Adverse Weather	26	39	76	14	24	179	4.0%
7-Adverse Environment	3	7	3	4	0	17	0.4%
8-Human Element	10	8	6	5	6	35	0.8%
9-Foreign Interference	258	236	182	173	202	1051	23.7%
Total[3]	992	1011	850	692	896	4441	100%

Figure 10: Number and Percentage of Outages by Cause Codes (Excluding MEDs)

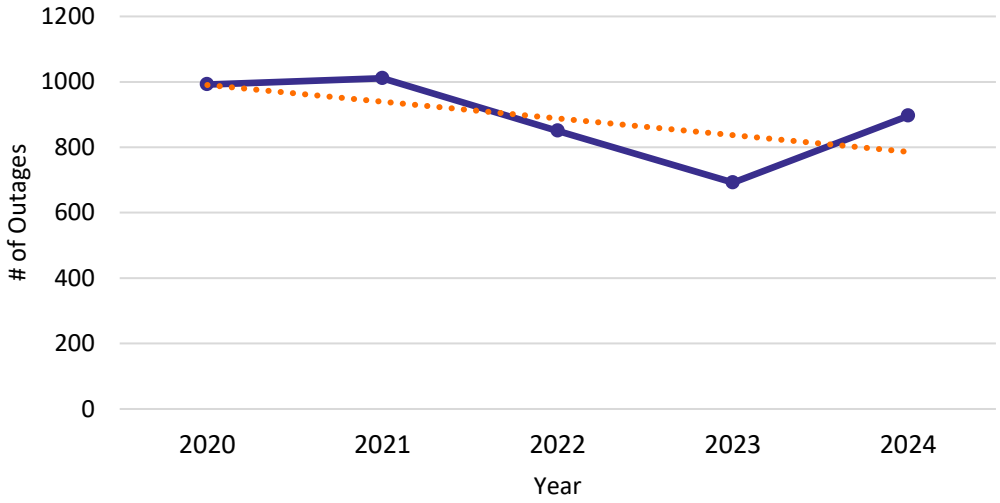


	0-Unknown	1-Scheduled Outage	2-Loss of Supply	3-Tree Contacts	4-Lightning	5-Defective Equipment	6-Adverse Weather	7-Adverse Environment	8-Human Element	9-Foreign Interference
2020	104	121	36	87	3	344	26	3	10	258
2021	130	164	36	98	3	290	39	7	8	236
2022	113	141	37	101	2	189	76	3	6	182
2023	114	136	20	75	11	140	14	4	5	173
2024	136	128	32	134	6	228	24	0	6	202
Contribution	13%	16%	4%	11%	1%	27%	4%	0%	1%	24%

Further details on individual cause codes are provided in the subsections below. The subsections below outline the specific factors contributing to outages, including a description of the cause, its impact on overall reliability metrics, and relevant performance trends.

[3] Numbers may not sum due to rounding.

Figure 11: Total Number of Outages per Year (Excluding MEDs)



The total number of interruptions over the historical period is shown in Figure 11 above (excluding MEDs), varying from a low of 692 to a high of 1,011, with an overall decreasing trend during the period. This represents an average of 1.90 to 2.77 interruptions per day.

Defective equipment (27%), foreign interference (24%), and scheduled outages (16%) have been identified to be the three most common causes for interruptions on Elexicon's distribution system over the historical period. Together these causes contributed to 66% of the total number of interruptions from 2020 to 2024, excluding MEDs.

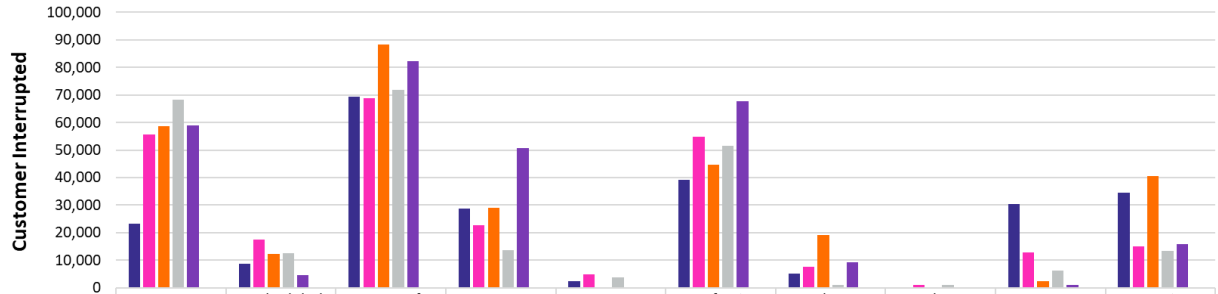
2.3 Customer Interruption & Customer Hours of Interruption

The number of Customer Interruption (CI) is a measure of the total number of customers interrupted during a sustained interruption event. Customer Hours of Interruption (CHI) is a measure of the sum of the duration of interruptions experienced by all affected customers. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 23: Customer Interruption Numbers by Cause Codes – Excluding MEDs

Cause Code	**2020**	**2021**	**2022**	**2023**	**2024**	Total CI	%
0-Unknown/Other	23,143	55,744	58,730	68,282	58,865	264,764	19.9%
1-Scheduled Outage	8,712	17,608	12,152	12,546	4,700	55,718	4.2%
2-Loss of Supply	69,277	68,892	88,395	71,932	82,379	380,875	28.6%
3-Tree Contacts	28,842	22,639	28,935	13,638	50,726	144,780	10.9%
4-Lightning	2,502	4,975	11	3,686	241	11,415	0.9%
5-Defective Equipment	39,049	54,700	44,699	51,410	67,814	257,672	19.3%
6-Adverse Weather	5,196	7,553	19,198	1,144	9,206	42,297	3.2%
7-Adverse Environment	55	1,102	36	1,007	0	2,200	0.2%
8-Human Element	30,470	12,828	2,499	6,293	1,073	53,163	4.0%
9-Foreign Interference	34,445	14,989	40,648	13,323	15,849	119,254	9.0%
Total[4]	241,691	261,030	295,303	243,261	290,853	1,332,138	100%

Figure 12: Number and Percentage of CIs by Cause Codes (Excluding MEDs)



	0-Unknown	1-Scheduled Outage	2-Loss of Supply	3-Tree Contacts	4-Lightning	5-Defective Equipment	6-Adverse Weather	7-Adverse Environment	8-Human Element	9-Foreign Interference
2020	23,143	8,712	69,277	28,842	2,502	39,049	5,196	55	30,470	34,445
2021	55,744	17,608	68,892	22,639	4,975	54,700	7,553	1,102	12,828	14,989
2022	58,730	12,152	88,395	28,935	11	44,699	19,198	36	2,499	40,648
2023	68,282	12,546	71,932	13,638	3,686	51,410	1,144	1,007	6,293	13,323
2024	58,865	4,700	82,379	50,726	241	67,814	9,206	0	1,073	15,849
Contribution	20%	4%	29%	11%	1%	19%	3%	0%	4%	9%

[4] Numbers may not sum due to rounding.

Figure 13: Total Number of Customer Interruption per Year (Excluding MEDs)

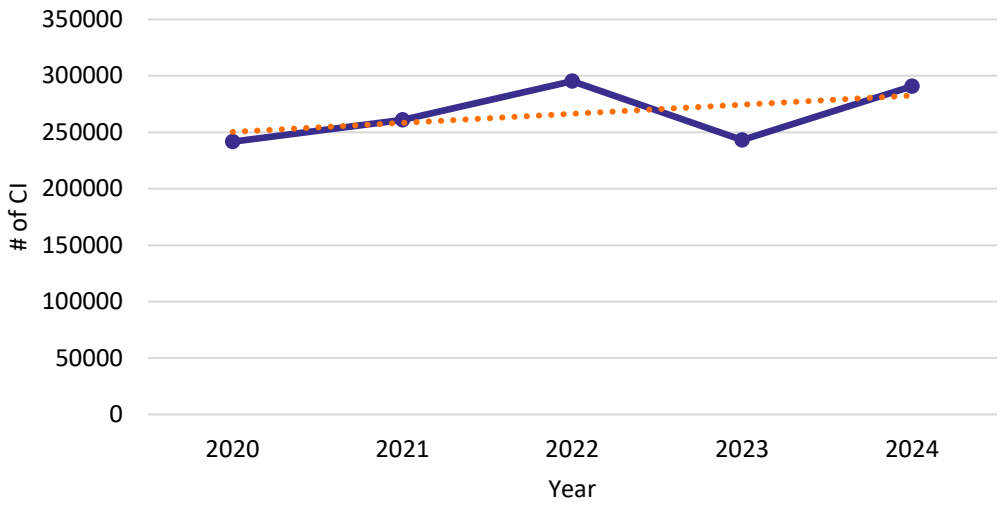
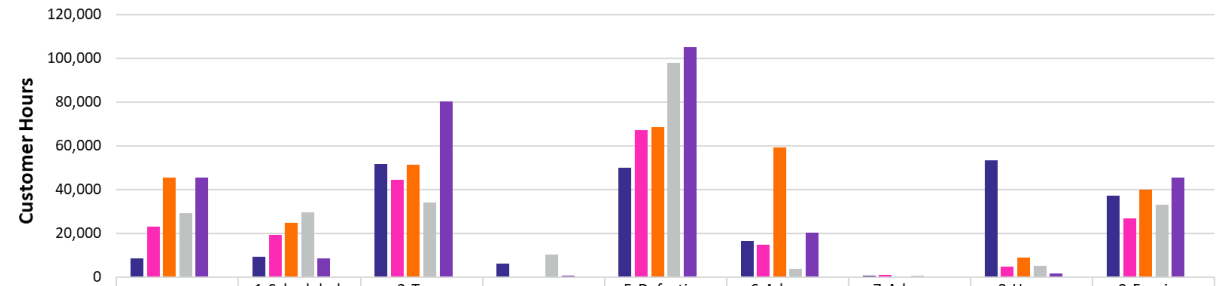


Table 24: Customer Hours of Interruption Numbers (rounded) by Cause Codes – Excluding MEDs

Cause Code	**2020**	**2021**	**2022**	**2023**	**2024**	Total CHI	%
0-Unknown/Other	8456	23003	45390	29094	45526	151469	8.7%
1-Scheduled Outage	9169	19273	24805	29515	8444	91206	5.2%
2-Loss of Supply	101813	42505	147307	96214	69624	457463	26.3%
3-Tree Contacts	51693	44561	51318	34045	80186	261803	15.0%
4-Lightning	6162	171	13	10333	498	17177	1.0%
5-Defective Equipment	49873	67016	68411	97727	105055	388082	22.3%
6-Adverse Weather	16396	14768	59124	3825	20385	114498	6.6%
7-Adverse Environment	552	940	129	615	0	2235	0.1%
8-Human Element	53497	4755	8967	4957	1558	73734	4.2%
9-Foreign Interference	37125	26927	39847	33139	45358	182396	10.5%
Total[5]	334738	243919	445311	339464	376634	1740064	100%

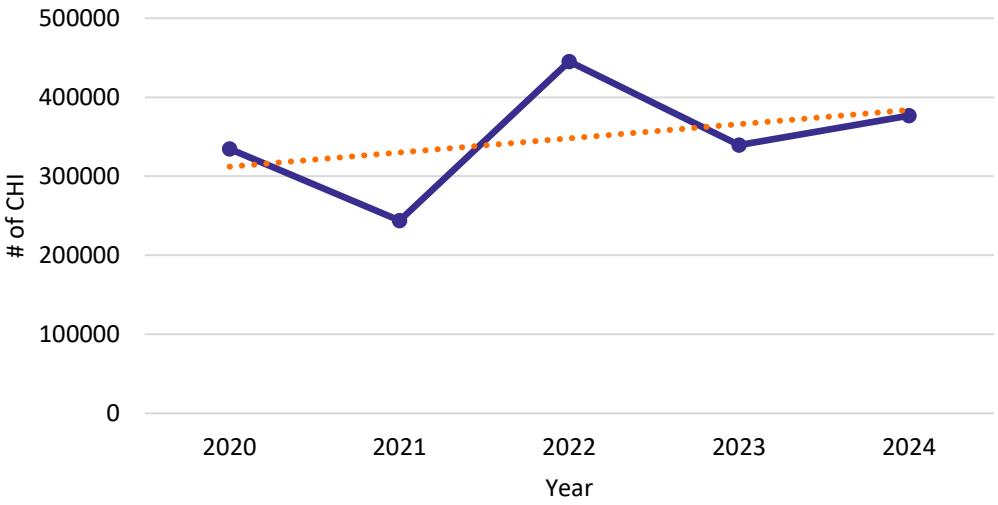
[5] Numbers may not sum due to rounding.

***Figure 14*: Number and Percentage of CHIs by Cause Codes (Excluding MEDs)**



	0-Unknown	1-Scheduled Outage	3-Tree Contacts	4-Lightning	5-Defective Equipment	6-Adverse Weather	7-Adverse Environment	8-Human Element	9-Foreign Interference
2020	8,456	9,169	51,693	6,162	49,873	16,396	552	53,497	37,125
2021	23,003	19,273	44,561	171	67,016	14,768	940	4,755	26,927
2022	45,390	24,805	51,318	13	68,411	59,124	129	8,967	39,847
2023	29,094	29,515	34,045	10,333	97,727	3,825	615	4,957	33,139
2024	45,526	8,444	80,186	498	105,055	20,385	0	1,558	45,358
Contribution	9%	5%	15%	1%	22%	7%	0%	4%	10%

Figure 15: Total Number of Customer Hours of Interruption per Year (Excluding MEDs)



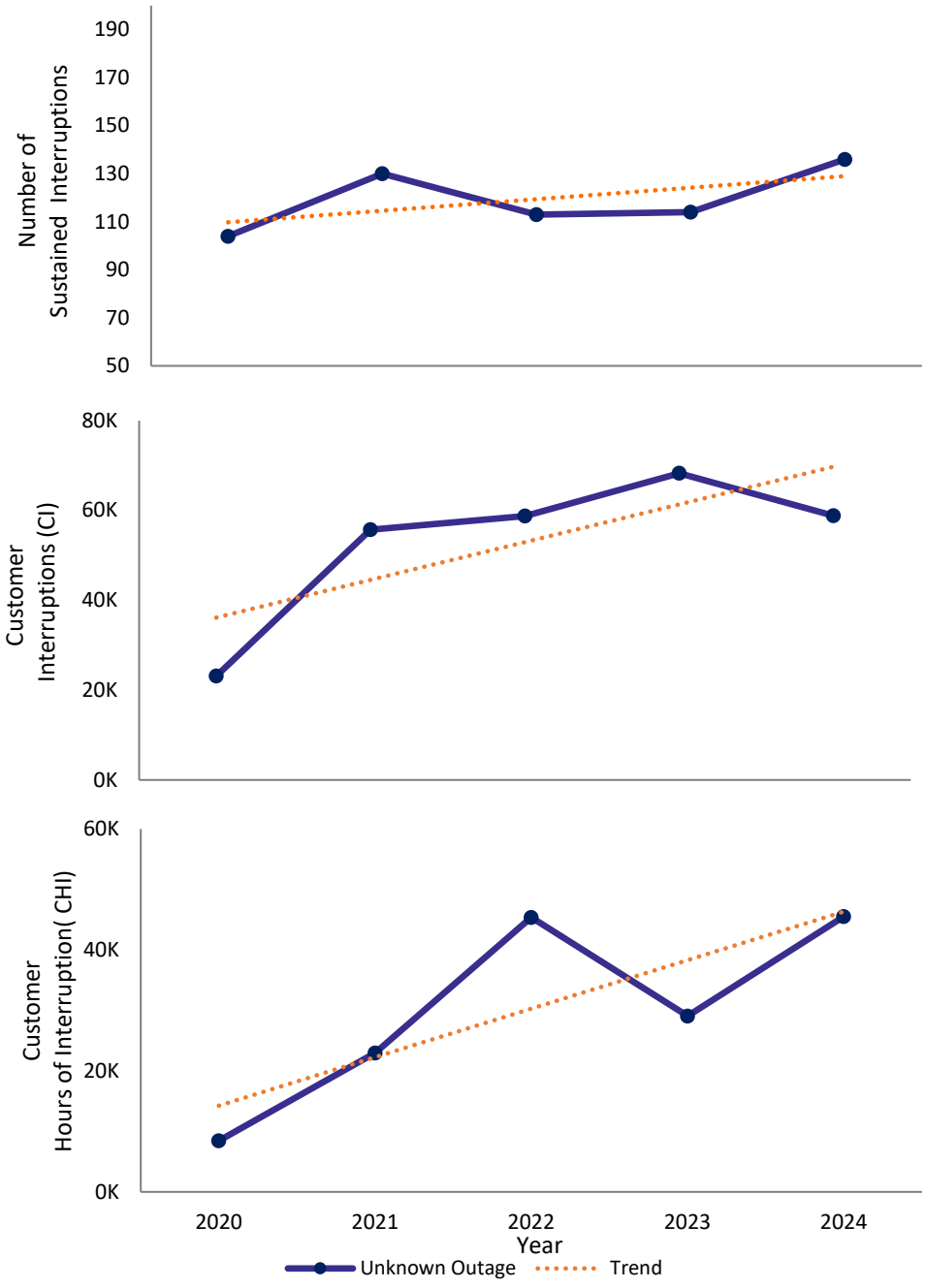
The trend for total Customer Interruptions (CI) and Customer Hours of Interruption (CHI) from 2020 to 2024 is on a rising trend. This trend indicates deteriorating reliability for Elexicon customers with increase in both the frequency and duration of the outages. The top three contributors to CI during this period were Loss of Supply (29%), Unknowns (20%), and Defective Equipment (19%). Similarly, for CHI, the leading

contributors were Loss of Supply (26%), Defective Equipment (22%), and Tree Contacts (15%). Across the historical period, LOS have been the top contributor to both CHI and CI although these outages are beyond Elexicon' s control and are attributed to the upstream transmitter, Hydro One. The rising trend of both CI and CHI due to defective equipment and tree contacts underscores the importance of Elexicon's continued investment in system renewal (Exhibit 2B - Tab 4 - Schedule 1), vegetation management (Exhibit 4 - Tab 1 - Schedule 4), and Grid Modernization (Exhibit 2B - Tab 3 - Schedule 2 - Appendix A) to improve outage response capability, long-term reliability and reduce customer impact.

The following section provides a detailed analysis of historical reliability performance by cause code, including the number of interruptions, Customer Interruptions (CI), Customer Hours of Interruption (CHI) and key events that have influenced these trends along with planned mitigation strategies over the 2027–2031 DSP period.

2.4 Unknown Outages

Figure 16: Number of interruptions, CI and CHI due to Unknown Outages (2020-2024)

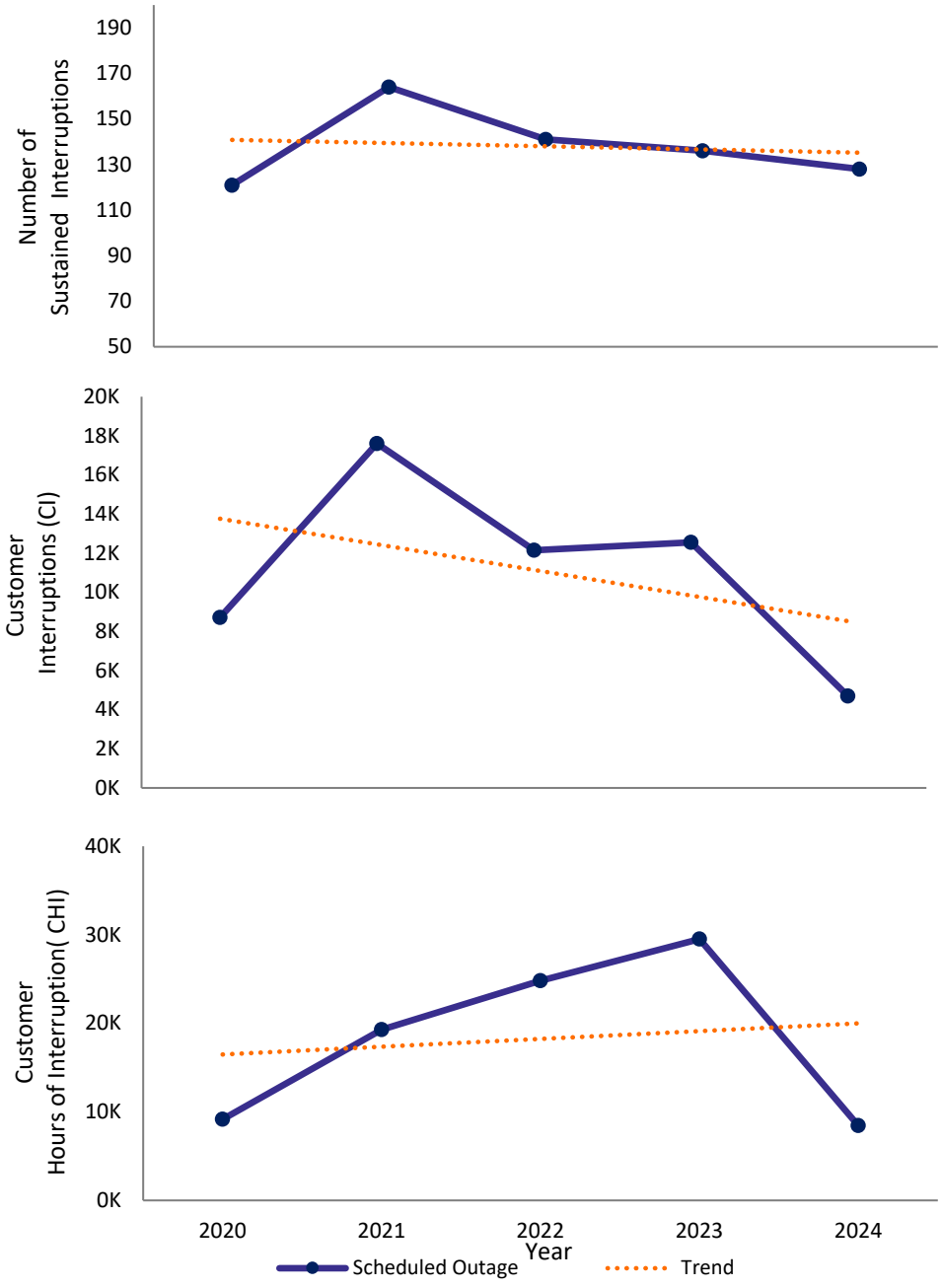


Unknown/other outages are classified events where root cause cannot be identified or is inconclusive. Unknown/other outages are on a rising trend between 2020 and 2024, resulting in 597 interruptions, 151,469 CHI and 264,764 CI during this period, as seen in Figure 16.

Elexicon conducts system patrols following an outage to investigate the root cause; however, in some cases, the root cause cannot be identified leading to an outage to be classified as unknown/other. To improve the identification of unknown/other outages, Elexicon plans to invest in grid modernization technologies as part of its Grid Enhancement program (Exhibit 2B - Tab 4 - Schedule 3 – Appendix J). Over the 2027-2031 period, grid modernization investments will support the reduction of outages classified as unknown by strengthening system visibility and fault detection through leveraging technologies such as SCADA-enabled switches, CFCIs, AMI 2.0, and ADMS that will provide real-time information on fault location and system conditions. These technologies will help reduce reliance on manual patrols, and enable more definitive root-cause identification, thereby lowering the number of outages classified as unknown.

2.5 Scheduled Outages

Figure 17: **Number of interruptions, CI and CHI due to Scheduled Outages (2020-2024)**



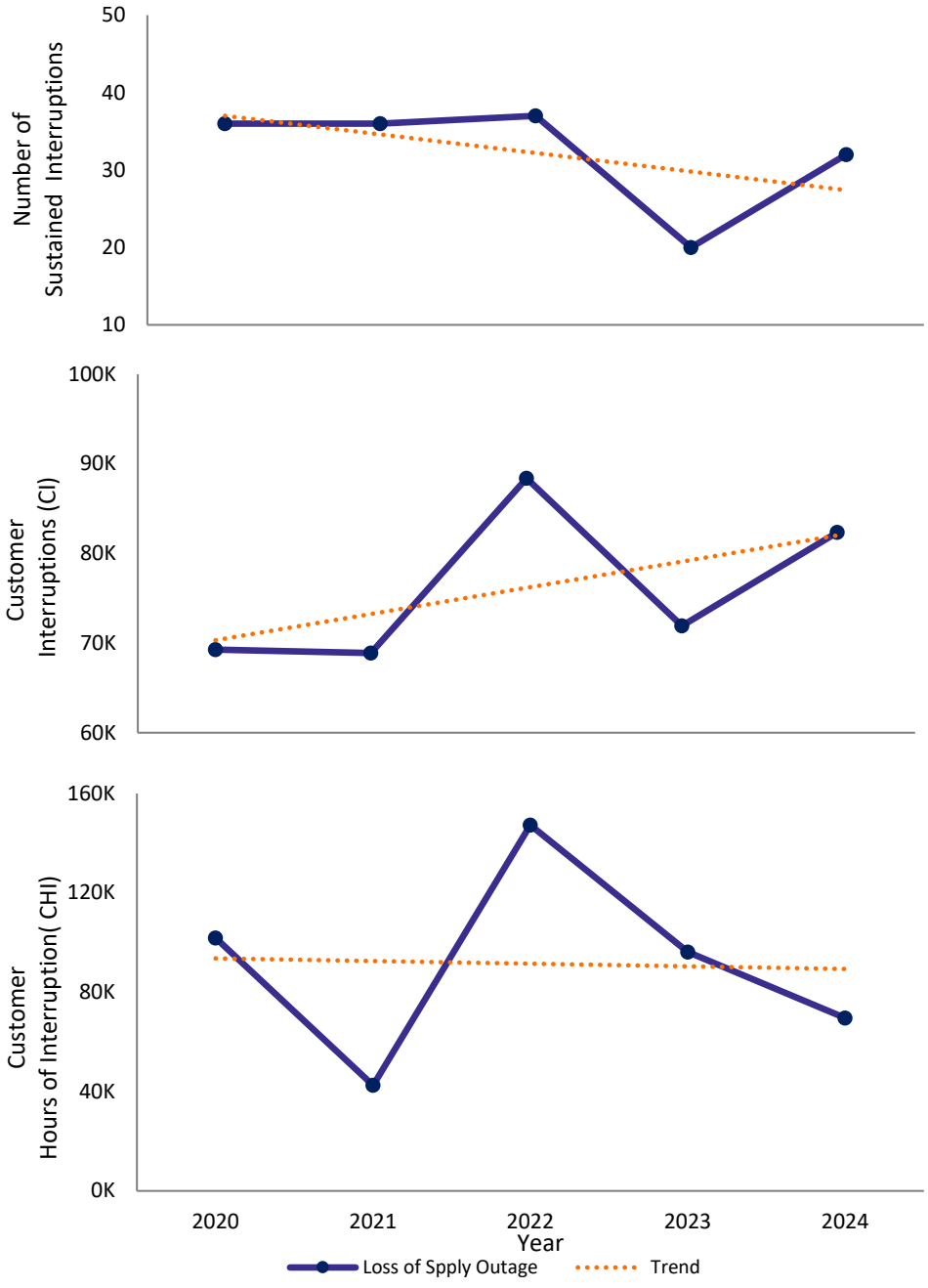
Scheduled Outages are interruptions due to disconnection of customers as part of planned capital or maintenance work. These outages also include any unplanned maintenance or restoration work such as forced outages to address emerging system needs such as switching and sectionalizing due to emergencies or fires requiring isolation. Over the historical period of 2020-2024, the number of sustained interruptions and customer interruption have decreased slightly within Scheduled Outages as result of improved planning activities, as seen in Figure 17. A significant drop in 2024 was due to reduction in planned capital projects resulting from capital investment constraints. However, customer hours are on a slightly increasing trend due to aging infrastructure and damage from storms requiring forced outages for emergency repairs.

Throughout the 2027-2031 DSP period, Elexicon will undertake targeted System Service investments (Exhibit 2B - Tab 4 - Schedule 1) including construction of new substations, feeder enhancements and investing in grid modernization technologies. These investments will reduce risk for customers on radial lines, improve sectionalizing capabilities and system redundancy to mitigate scheduled customer interruptions during construction and maintenance activities.

Elexicon continues to take proactive steps in controlling scheduled outages by employing measures such as installing temporary switches, scheduling outages during periods of minimal disruption to customers and live-line work method to mitigate the number of customers affected. As part of the Substation Growth investment program, Elexicon will invest in a mobile substation to enhance system resiliency in capacity constrained areas during planned outages and reduce customer impacts in the event of subsequent unplanned outages. Additionally, project synergies are also considered when planning outages for capital or maintenance work to ensure minimal disruption to customers.

2.6 Loss of Supply

Figure 18: Number of interruptions, CI and CHI due to Loss of Supply outages (2020-2024)



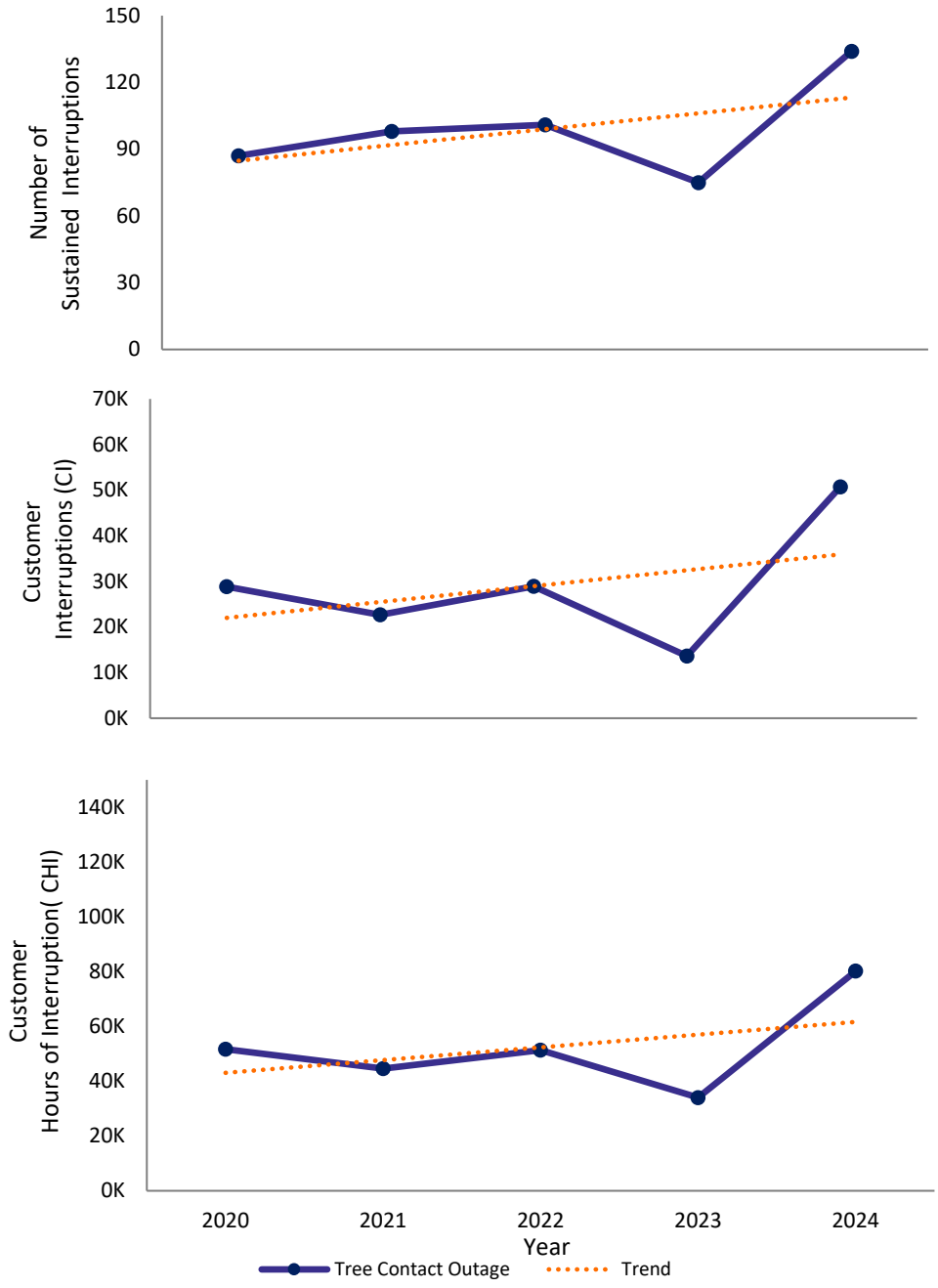
Loss of Supply (LOS) outages refers to interruptions caused by an upstream distribution or transmission system outage. These outages are beyond Elexicon's control and is attributed to its upstream transmitter, Hydro One. Over the historical period of 2020-2024, LOS outages are on a slightly declining trend, with a total of 161 sustained interruptions, resulting in 457,463 CHI.

However, the number of customer interruption has been increasing. This increase is primarily attributed to the larger number of customer base impacted from LOS events that disrupt Elexicon owned substations and distribution system infrastructure. Portions of Elexicon's service territory are supplied via radial supply points, which can contribute to higher customer impact when a LOS outage occurs. Additionally, rural areas, such as Gravenhurst, are more susceptible to LOS interruption due to severe weather events. Between 2020 and 2024, Gravenhurst LOS outages resulted in 62 interruptions and 180,491 CHI.

To mitigate interruptions related to LOS, Elexicon actively monitors its supply points and regularly engages with its upstream distributor and transmitter, Hydro One. This ongoing engagement aims to identify and implement reliability improvements that minimize the impact of LOS events on Elexicon's customers. Over the past five years, Elexicon has reconfigured and introduced new supply points in areas with historically poor reliability of supply, such as Gravenhurst and Clarington. These efforts have contributed to an improvement in the number of LOS-related interruptions as illustrated in Figure 18.

2.7 Tree Contacts

Figure 19: Number of interruptions, CI and CHI due to Tree Contacts (2020-2024)



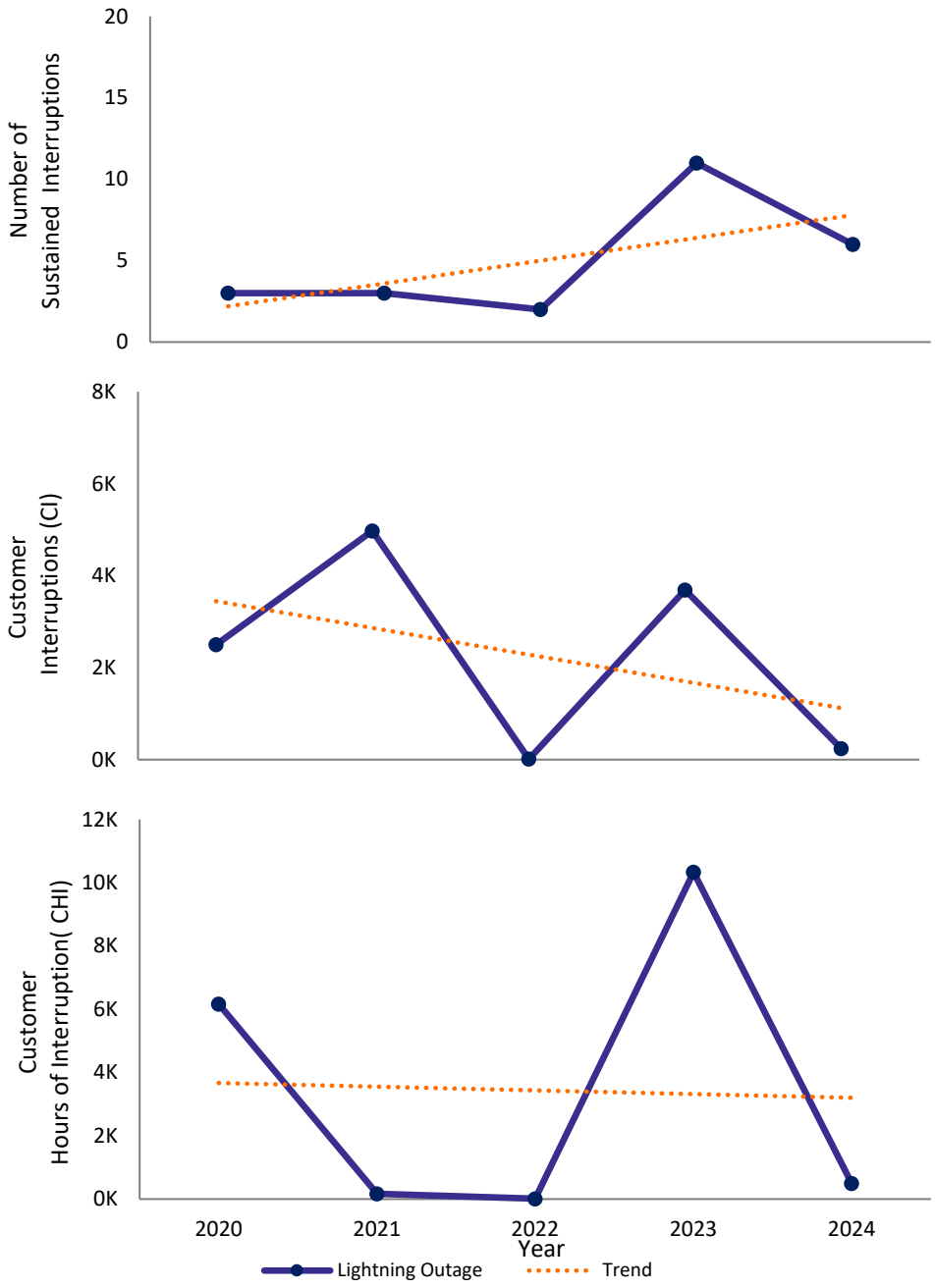
Tree contact outages are caused by vegetation contacting the energized overhead circuits and are a significant reliability concern for Elexicon. Tree contacts have contributed 15% to the overall customer hours over the historical period of 2020-2024 and is one of the top three contributors to the Elexicon's SAIDI performance. As illustrated in Figure 19, the number of interruptions, customers affected, and customer hours have all trended upwards with a sharp increase in 2024. This increase is mainly due to weather events and storms that did not meet the Major Event classification. Additionally, Elexicon's non-contiguous service territory spanning across rural and urban areas presents unique vegetation management challenges and requires Elexicon to strengthen its vegetation management strategy.

To mitigate the impact of tree contacts on reliability, Elexicon plans to strengthen its vegetation management practices through continued investment (Refer to Exhibit 4 - Tab 1 - Schedule 4). This includes leveraging technologies such as LiDAR[6] scanning and satellite imagery, powered by AI to map and monitor vegetation within its service territory. Additionally, capital investments in grid modernization technologies will aid in fault locating, improve sectionalizing capability and restoration times.

[6] LiDAR – Light Detection & Ranging

2.8 Lightning

Figure 20: **Number of interruptions, CI and CHI due to Lightning (2020-2024)**

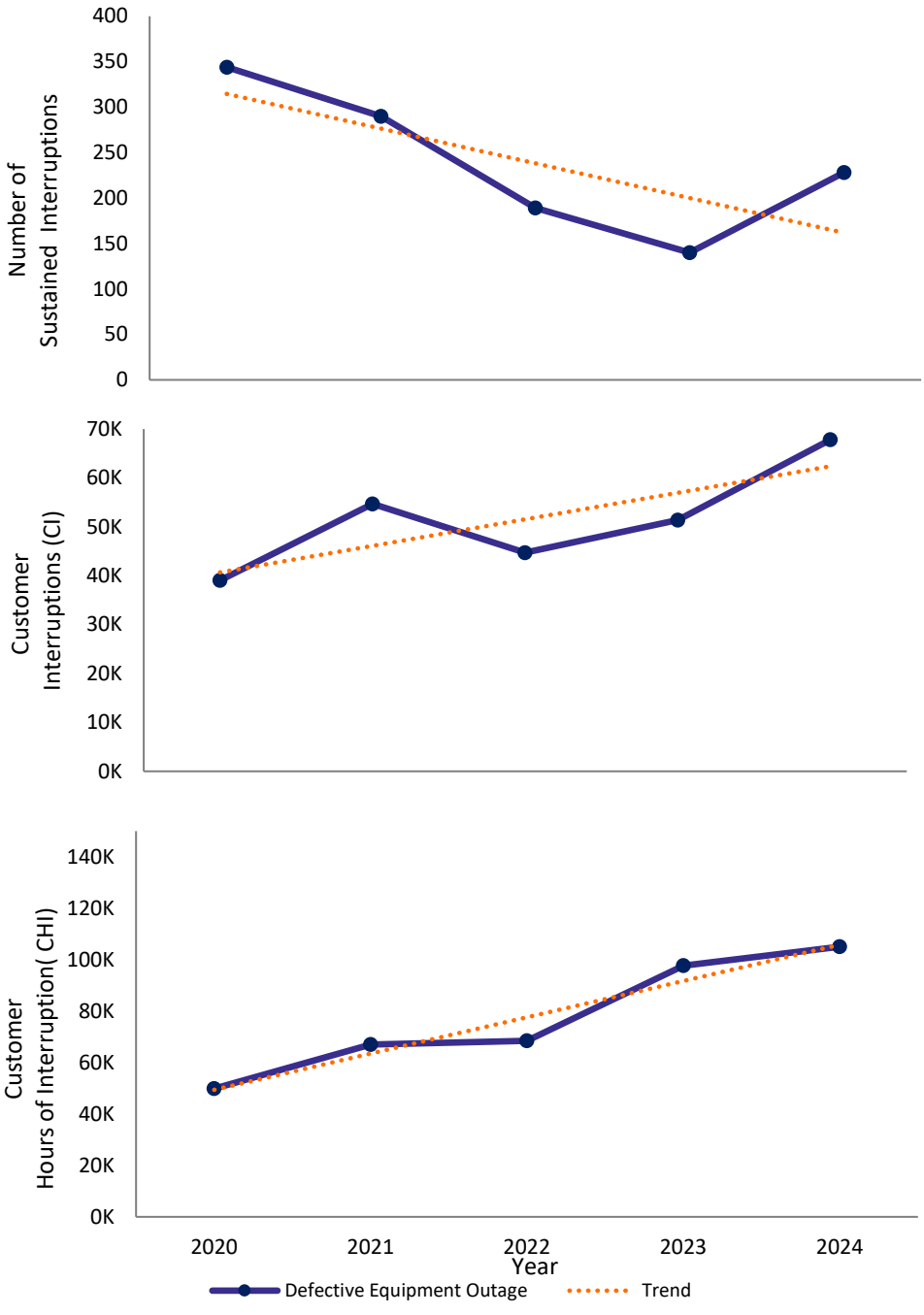


Lightning strikes can lead to insulation breakdowns, flashovers, and pole fires, resulting in faults that interrupt service to customers. They also cause overvoltage's and transients that can damage distribution equipment. Over the historical period of 2020-2024, while the number of lightning related interruptions has slightly increased, both the number of customers affected and the total customer hours of interruption have shown a downward trend, as illustrated in Figure 20.

To mitigate the impact of lightning on system reliability and customer service, Elexicon employs standards aimed at shielding its distribution system. These include the installation of surge arresters on overhead distribution lines and substations, as well as setting appropriate protection schemes across the network. Over the 2027-2031 DSP period, Elexicon plans to enhance lightning protection by investing in its System Service portfolio, targeting areas most vulnerable to lightning strikes.

2.9 Defective Equipment

Figure 21: **Number of interruptions, CI and CHI due to Defective Equipment (2020-2024)**



Defective equipment has been one of the top leading causes of poor SAIDI performance over the past five years. Over the historical period of 2020-2024, Defective Equipment contributed to 22% to Elexicon SAIDI and has been identified as significant reliability risk to Elexicon customers. While the number of interruptions decreased during 2020-2023, primarily due to a reduction in non-major equipment failures such as secondary service connections, elbows and inserts and accessories, both customer hours of interruption and customer interruptions have risen sharply throughout the historical period, as seen in Figure 21. This trend is largely attributed to Elexicon's aging and deteriorating asset base, which has resulted in major equipment failing causing large scale prolonged outages that impacted a larger number of customers. In 2024 the number of interruptions, CI and CHI all rose significantly, underscoring the reliability risks associated with Elexicon' s aging and deteriorating distribution infrastructure.

As of 2025, 13% of Elexicon's distribution assets are in poor or very poor shape. Similarly, 14% of stations are in poor or very poor shape, requiring intervention. The top three contributors to the defective equipment CI and CHI over the historical period were underground primary cables, overhead primary connections and sleeves and defective switches. Similarly, the top three contributors to the number of defective equipment outages were underground primary cables, underground secondary cables and overhead service connections and sleeves. These assets represent the most frequent and the highest-impact contributors to defective equipment related outages.

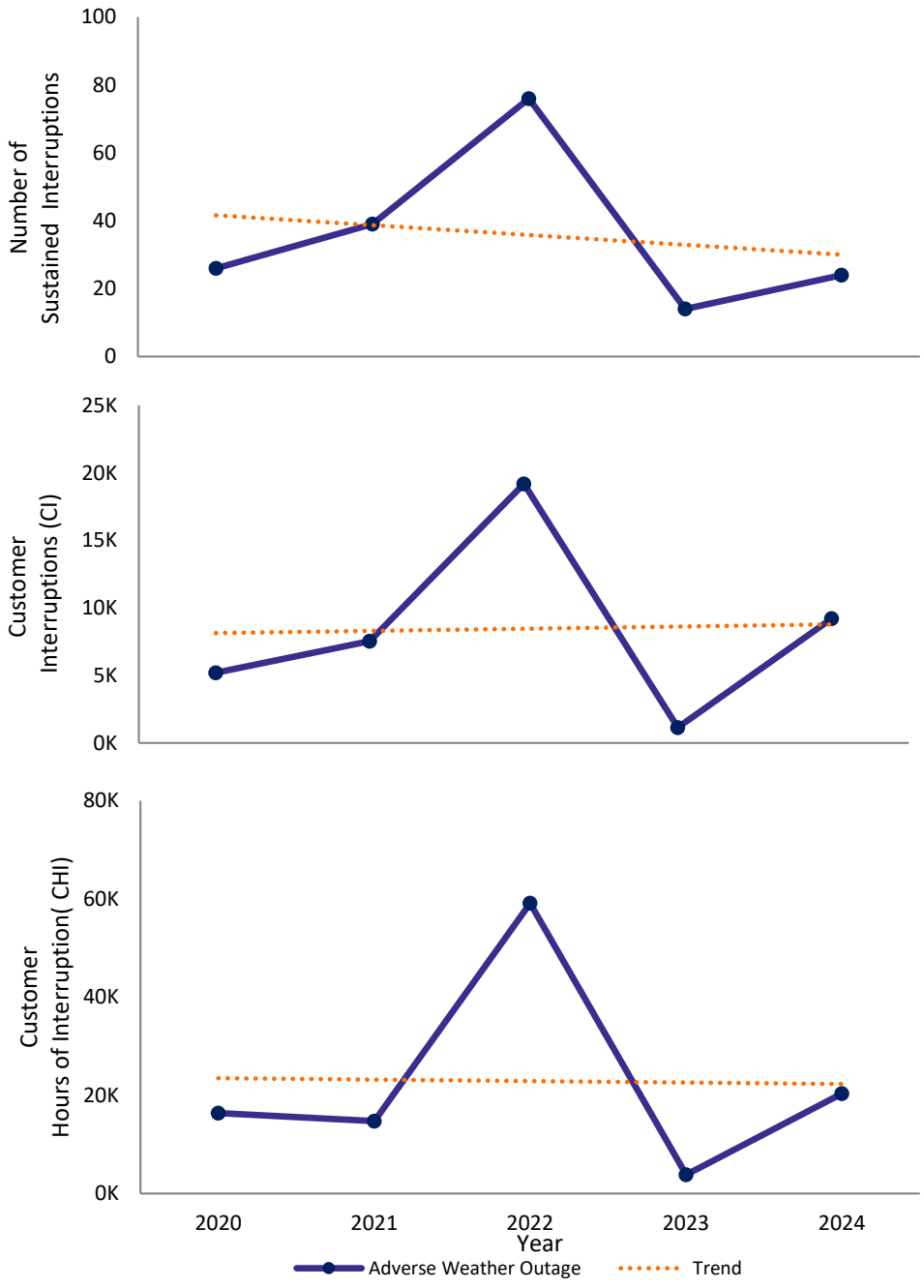
Over the 2027-2031 DSP period, Elexicon plans to address these challenges by:

- Investing in the renewal of substation and distribution assets in poor or very poor condition through its System Renewal portfolio (For further details, refer to Exhibit 2B – Tab 4 – Schedule 3 – Appendices E-H),
- Investing in new feeder enhancements and constructing new stations through its System Service portfolio to address contingency issues and improve supply resiliency (For further details, refer to Exhibit 2B – Tab 4 – Schedule 3 – Appendices I-K)

- Modernizing the grid to reduce outage durations caused by defective equipment, including the deployment of smart technologies for fault detection and sectionalizing to support with the objectives in the Grid Modernization Plan (Exhibit 2B – Tab 3 – Schedule 2 – Appendix A), and
- Enhancing inspection and maintenance practices, to proactively identify and address equipment issues before they lead to asset failure, thereby improving overall system reliability and reducing customer impact. Further details are outlined in Exhibit 4 - Tab 1 - Schedule 4.

2.10 Adverse Weather

Figure 22: Number of interruptions, CI and CHI due to Adverse Weather-related outages (2020-2024)



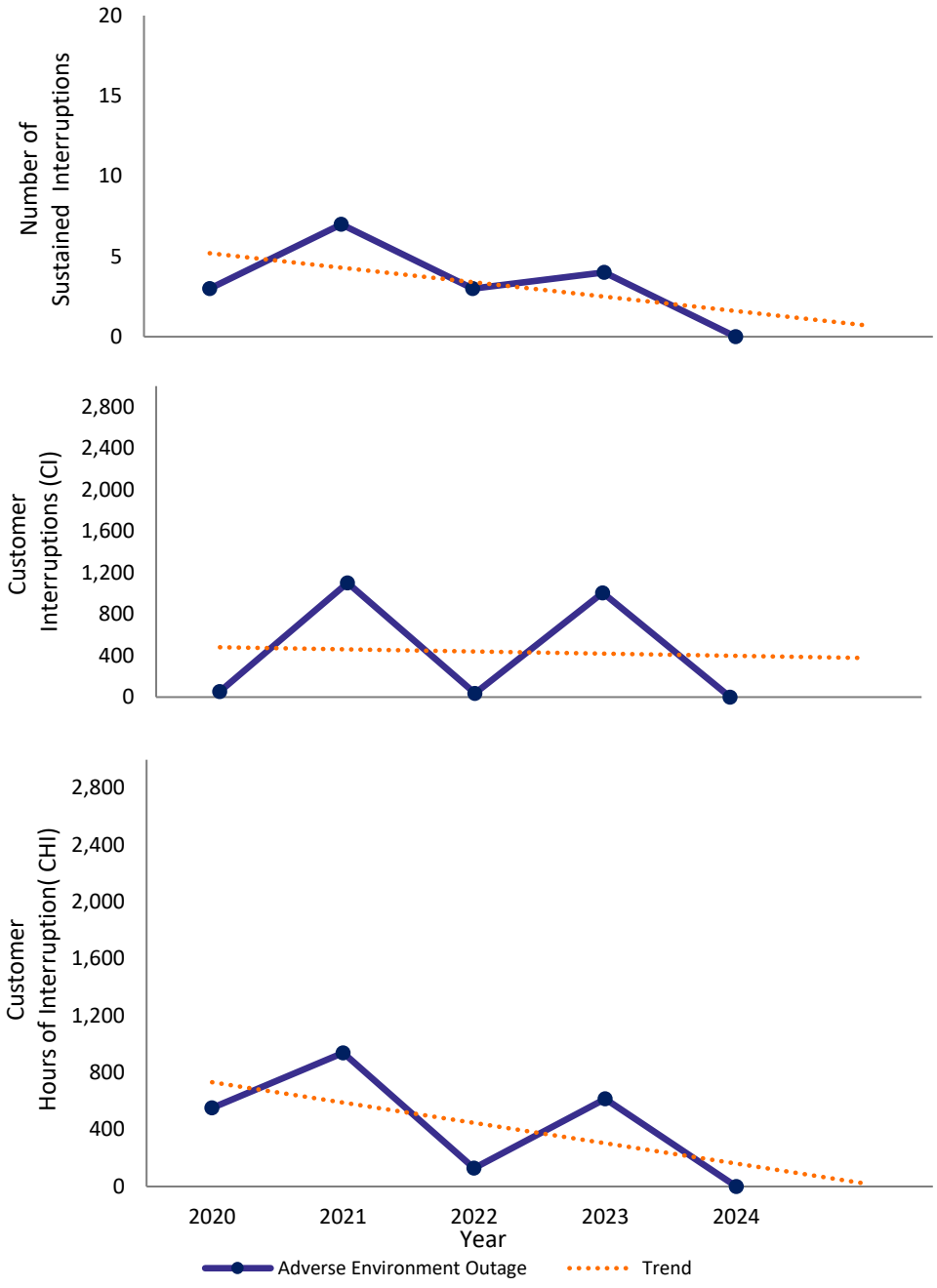
Adverse Weather-related interruptions are caused by severe weather events such as heavy rain, snowstorms, windstorms (with wind speeds exceeding 90 km/h), freezing rain, hail, and other extreme conditions excluding MEDs. These events are beyond Elexicon's control and can have a significant impact on the reliability of its distribution system.

Over the historical period of 2020-2024, Elexicon has experienced multiple Adverse Weather events that resulted in damage to its infrastructure and service interruptions for customers. As illustrated in Figure 22, the number of interruptions, customers affected, and total customer hours associated with Adverse Weather have been declining in recent years. In 2022, Elexicon experienced a sharp increase in adverse weather events, many of which were tied to the aftermath of major storms. Restoration efforts and repairs often extended for several days beyond the official classification of the Major Event. While many of these events qualified as Major Event Days (MEDs), some only impacted portion of Elexicon's distribution system and did not meet the threshold for MED classification.

To mitigate the impacts of adverse weather, and consistent with the Ontario Energy Board's Vulnerability Assessment and System Hardening (VASH) initiative, Elexicon continues to assess opportunities to incorporate grid modernization investments that strengthen system resiliency. Through the targeted deployment of automated switching, fault-detection technologies, protective devices, and station-level monitoring (Refer to Grid Enhancements Material Narrative in Exhibit 2B - Tab 4 - Schedule 3 - Appendix J), Elexicon aims to enhance system response during severe weather events and improve the ability to maintain service under increasingly variable operating conditions.

2.11 Adverse Environment

Figure 23: Number of interruptions, CI and CHI due to Adverse Environment related outages (2020-2024)

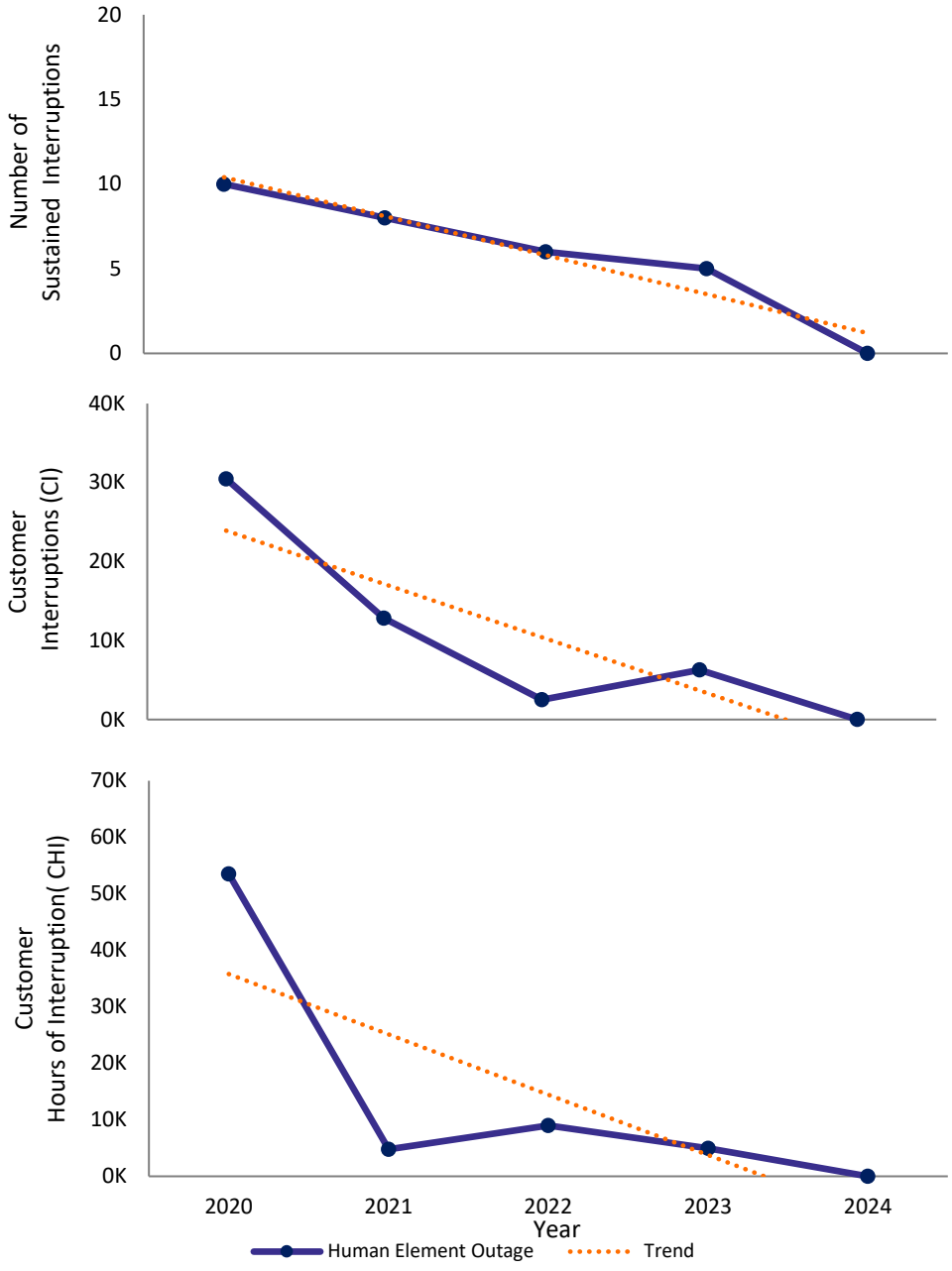


Adverse Environment are customer interruptions caused by abnormal environmental conditions such as salt spray, industrial contamination, humidity, corrosion, fire or flooding. Over the historical period of 2020-2024, the number of interruptions, customer hours of interruption and customer interruptions are on a declining trend, as can be seen in Figure 23. There were 17 interruptions reported during this period primarily resulting from fires spreading on distribution assets caused by foreign objects/vandalism or contamination of insulators from salt spray resulting in pole fires. Elexicon regularly monitors these events and conducts an annual insulator washing program.

Over the 2027-2031 DSP period, Elexicon will enhance the insulator washing program to mitigate pole fires resulting from environmental and salt contamination (Refer to Exhibit 4 - Tab 1 - Schedule 4). Additionally, through its renewal capital plan, Elexicon is continuing to replace legacy porcelain insulators and cut outs with polymer to further reduce pole fire risks (Refer to Exhibit 2B - Tab 4 - Schedule 3 – Appendix G).

2.12 Human Element

Figure 24: Number of interruptions, CI and CHI due to Human Elements (2020-2024)



Elexicon has made significant progress in reducing interruptions associated with human elements, i.e., events linked to staff interactions with the distribution system, such as switching errors, improper construction or maintenance activities, improper protection settings, installation errors, and utility arborist errors. Although 2020 marked a temporary peak driven by switching, construction, and maintenance incidents, the historical period of 2020-2024 show a sharp decline in both the number of outages and the associated CHI and CI as seen in Figure 24.

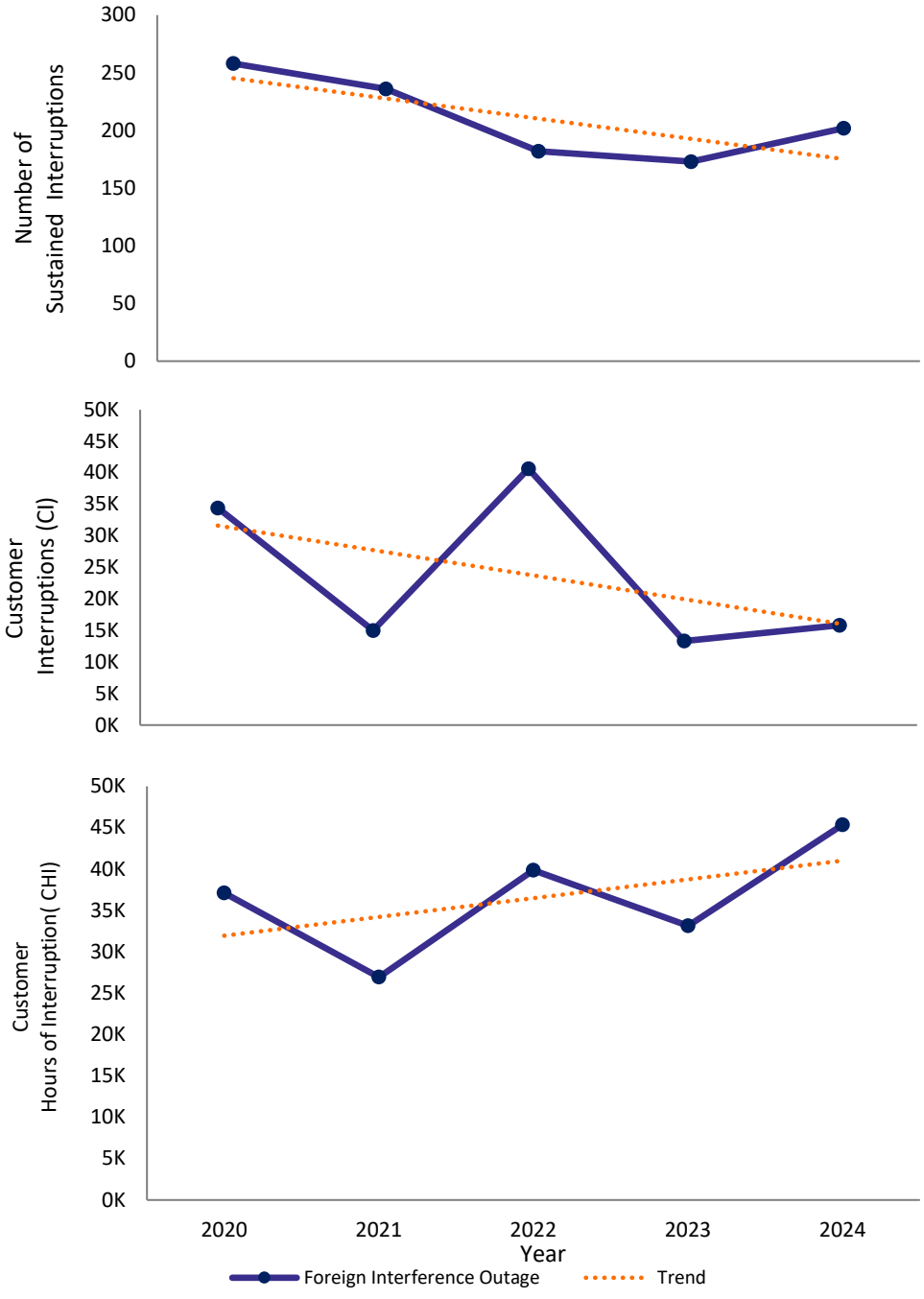
This improvement is largely driven by Elexicon's robust control mechanisms aimed at reducing human-error-related events. To ensure that standard operating procedures (SOPs) are consistently followed by both utility staff and contractors during interactions with the distribution system, Elexicon implements a comprehensive set of practices, including:

- Comprehensive training programs to ensure staff are well-equipped to perform their duties safely and effectively,
- Thorough investigations of near-miss incidents to identify root causes and areas for improvement,
- Systematic sharing of lessons learned across teams to promote continuous learning,
- Implementation of corrective actions to prevent recurrence, and
- Through the development and communication of construction standards to relevant staff

These practices are designed to mitigate reliability risk and promote a culture of safety.

2.13 Foreign Interference

Figure 25: **Number of interruptions, CI and CHI due to Foreign Interference outages (2020-2024)**



Foreign interface interruptions are customer interruption caused by external factors normally beyond the control of the utility. These outages include interruptions caused by animals, vehicles accidents, dig-ins, customer owned equipment and DER, sabotage, vandalism and foreign objects. Over the historical period of 2020-2024, interruptions and customer interruption caused by Foreign Interference are on a declining trend as seen in Figure 25; however, customer hours are on the rise, primarily due to larger customer base interrupted and longer outage durations.

The majority (80%) of the foreign interference interruptions are attributed to animal contacts and is one of top leading contributor to Elexicon's SAIDI performance over the 2020-2024 period. To mitigate the impact of foreign interference outages, Elexicon is making targeted investments through the System Service Investment Portfolio. This includes the strategic installation of animal guards, prioritized on the Worst Performing Feeders (WPFs) and in areas prone to such incidents. Additionally, Elexicon is investing in grid modernization technologies such as fault location and sectionalizing capabilities to reduce the number of customers affected during such incidents and to improve restoration times (Further details on this are presented in Exhibit 2B - Tab 4 - Schedule 3 - Appendix J).

3. DISTRIBUTOR SPECIFIC RELIABILITY TARGETS

Elexicon has developed reliability metrics to complement the standard SAIDI and SAIFI indicators required under the OEB's Scorecard. These reliability metrics establish performance expectations for the 2027 to 2031 period and reflect the capital and maintenance initiatives outlined in this application. They provide a structured basis for demonstrating the reliability performance Elexicon forecasts to deliver under the proposed investment plan. Further details on the proposed metrics are outlined in its Custom Scorecard in section 1.2 of this Schedule.

ASSET MANAGEMENT PROCESS

This section outlines Elexicon's Asset Management (AM) Process, describing key elements and methodologies that have informed the development of Elexicon's Capital Expenditure Plan. The objective of Elexicon's AM Process is to optimize the lifecycle of assets while ensuring the delivery of safe, reliable, and cost-effective electricity service to customers.

Elexicon's AM Process is based on evidence-based analysis, structured and risk-informed decision-making, and alignment with regulatory, safety, and engineering design standards. The AM Process provides a consistent and transparent approach for identifying needs, prioritizing investments, and optimizing the timing of expenditures to achieve system performance objectives and customer outcomes.

The following subsections describe Elexicon's structured AM Process, which transforms asset data and system performance insights into actionable, prioritized capital and maintenance investments.

1. PLANNING PROCESS

This section describes Elexicon's Asset Management planning process, including the key elements that have informed the development of Elexicon's Capital Expenditure Plan. As illustrated in Figure 1, the process is governed by a structured planning cycle that integrates data analytics, performance insights, and risk assessments to guide capital investment decisions. This approach ensures that planning activities remain evidence-based, repeatable, and aligned with investment plan objectives and regulatory obligations.

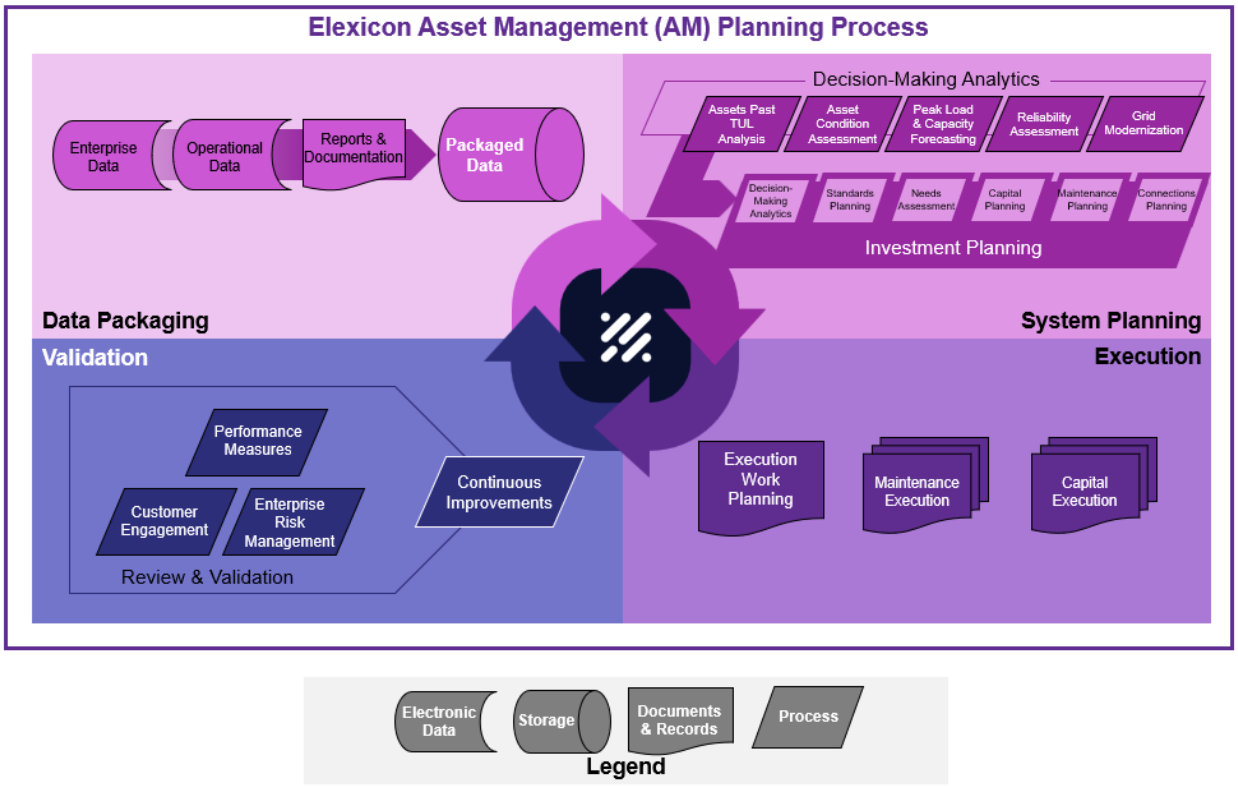
Integration of Corporate Strategy and Governance

Elexicon's strategic plan and governance structure provides the foundation for the AM planning process. Through Elexicon's investment plans, Elexicon seeks to achieve optimal alignment between cost, risk, and performance, while providing customers with reliable, affordable electricity, and ensuring that sustainable growth needs are met.

Cross-Functional Coordination

Through a structured governance model, investment decisions are coordinated across planning, engineering, and capital and maintenance work execution teams to ensure alignment with strategic priorities such as safety, system reliability performance, and financial responsibility. This collaborative approach ensures that capital and maintenance plans are practical, achievable, and reflect both near-term operational realities and long-term system needs.

Figure 1: Elexicon's AM Planning Process



Elexicon's AM Planning process provides a structured framework that supports achievement of both corporate and asset management objectives, while establishing the foundational inputs required for decision making, investment planning, and regulatory reporting.

The process is comprised of four interrelated stages**:** Data Packaging, System Planning, Execution, and Validation. Each stage represents a key function within Elexicon's planning process, collectively

transforming data and performance insights into actionable investment decisions. This structured process ensures that both capital and maintenance programs are risk-informed, cost-effective, and strategically aligned. Key Elements of the AM Planning Process are further discussed within Section 1.1 below.

1.1 Overview

This subsection provides an overview of the four core stages within Elexicon's AM planning process and describes how these stages interact to support effective decision-making and prioritization.

Data Packaging: This stage of the process focuses on the collection, harmonization, and consolidation of critical asset data from multiple sources, including inspections, testing, condition assessment, capacity analysis, supervisory control and data acquisition (SCADA), outage management system (OMS), advanced metering infrastructure (AMI), geographic information system (GIS), and enterprise resource planning (ERP) systems. These data sets form the foundation for evidence-based analysis and investment prioritization. Further details on this stage of the AM process are discussed in the Data Packaging section.

System Planning: In this stage, packaged data are transformed into analytical outputs through risk and condition assessment frameworks. Elexicon's distribution system needs are analyzed based on a variety of drivers including asset condition, system capacity, system reliability and resiliency and are coupled with the associated consequences across financial, customer, environmental, and safety dimensions. The outcomes guide the development of capital and maintenance programs that balance cost, risk, and performance. Further details on this stage of the AM process are discussed in the System Planning section.

Execution: This stage focuses on implementation of approved capital and maintenance investments identified through the planning process. Activities include finalizing work scopes, scheduling, and resourcing, followed by the delivery of field work through design, procurement, construction, and commissioning. The execution phase ensures that projects are completed safely, on-time, within budget, and to the required quality reliability and system performance. Further details on this stage of the AM process are discussed in the Execution section.

Validation: This stage involves the performance monitoring and feedback of the associated AM processes. Elexicon continuously measures investment outcomes using established performance metrics and short interval control processes to validate and ensure that objectives are achieved. Lessons learned from these

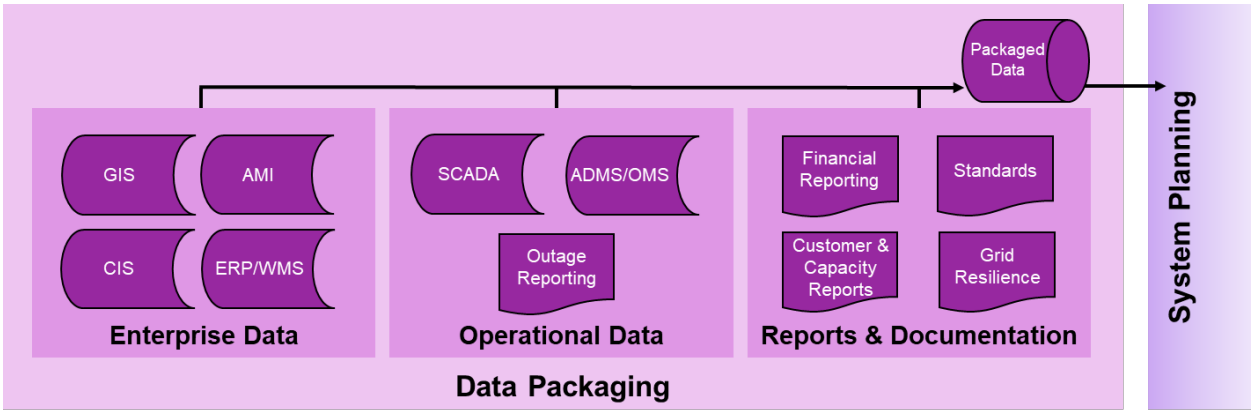
evaluations are used to refine the processes and strengthen future planning cycles. Further details on this stage of the AM process are discussed in the Validation section.

1.2 Data Packaging

Elexicon's Asset Management (AM) Process begins with Data Packaging, which represents the systematic consolidation of all foundational information required to support capital and maintenance investment decision-making in the System Planning stage. This step ensures that data from multiple enterprise systems, field inspections, operational monitoring, and financial records are organized, validated, and structured for analysis.

The Data Packaging process establishes a unified information base that feeds into subsequent planning and prioritization activities, enabling consistent, evidence-based decision-making across all asset classes. Figure 2 illustrates Elexicon's Data Packaging process within the overall AM Planning framework.

Figure 2: Data Packaging - AM Planning Process



1.2.1 Enterprise Data:

Enterprise Data represents information housed within Elexicon's corporate systems. These systems capture and maintain asset, customer, and operational information that enables analysis of performance, cost, and condition.

Key enterprise data sources include:

- **Geographic Information System (GIS):** Serves as the asset registry, containing spatial and attribute-level data for all assets. GIS maintains detailed information on asset location, configuration, connectivity, and characteristics (e.g. type, sub-type, installation year, material, manufacturer, size, voltage, and ownership).
- **Advanced Metering Infrastructure (AMI):** Enables near-real-time energy usage and outage detection, supporting system reliability and planning analysis.
- **Customer Information System (CIS):** Provides customer account and service connection details, billing history, and consumption data.
- **Enterprise Resource Planning (ERP)/Work Management System (WMS):** Serves as the central platform for managing work orders, maintenance activities, procurement, and financial transactions.

Collectively, these enterprise datasets form the backbone of Elexicon's asset registry and operational visibility, providing a foundation for the data analytics in planning and investment prioritization.

1.2.2 Operational Data:

Operational data represents system information captured through Elexicon's operational technology platforms. These systems provide visibility into network performance, asset operations, and system reliability, enabling both proactive and reactive decision making.

- **Supervisory Control and Data Acquisition (SCADA):** Monitors and controls the distribution system in real time, collecting telemetry data such as voltage, current, power factor, breaker status, and switching operations. SCADA data supports fault isolation, voltage management, and network reconfiguration.
- **Advanced Distribution Management System (ADMS) / Outage Management System (OMS):** Integrates system control, outage detection, and restoration management. These systems capture outage events with cause codes, timestamps, affected customer counts, and restoration details.

They also support operator workflows and analytics to improve fault response and service restoration efficiency.

- **Outage Reporting:** Consolidates event-level outage records and post-event analyses to produce key reliability metrics such as SAIDI and SAIFI. This dataset underpins System Reliability Reporting (SRR), regulatory filings, and trend analysis for continuous performance improvement.

This data is continuously reviewed to monitor reliability trends, assess outage performance, and support continuous improvement in operational practices. It also informs internal reporting processes which aggregates and summarizes performance insights for operational oversight and regulatory compliance.

1.2.3 Reports & Documentation:

Reports and documentation provide structured records that form the foundation for system planning by supporting consistent, informed, and compliant decision-making.

- **Financial Reporting:** This section encompasses all financial information associated with Elexicon's underlying assets and utility operations. It includes:
    - Scope Cost Estimates: Material and labour cost estimates required to replace or rehabilitate distribution assets.
    - Historical Financial Data: Capital and maintenance cost breakdowns for each investment program, organized by year. This data supports variance analysis activities.
    - Projected Financial Data: comprising anticipated capital and maintenance investment outcomes used to develop strategic investment plans.
    - Fixed Asset Module: Centralizes the management of Elexicon's capitalized assets and their depreciation schedules. These schedules are aligned with each asset's Typical Useful Life (TUL) to ensure accurate financial reporting and effective lifecycle management.
- **Standards:** This represents the documented standards leveraged by Elexicon to develop capital and maintenance investment projects. Elexicon maintains a series of standards and design documents that guide how assets are installed, replaced, and maintained, ensuring work is performed consistently and in compliance with applicable safety codes and industry practices.

These standards typically include schematics showing installation requirements and bills of materials specifying the components to be used.

- **Customer & Capacity Reports:** Elexicon leverages customer and system data to assess growth trends, evolving load profiles, and potential capacity constraints across its distribution network. These insights are informed through coordinated engagement with external stakeholders, including Hydro One and local municipalities, and supported by internal enterprise systems such as Advanced Metering Infrastructure (AMI), customer information platforms, and billing systems.

  Load forecasting and capacity planning activities incorporate consolidated and validated datasets, along with customer-specific inputs such as offers to connect, load inquiries, and other relevant data. This includes historical consumption patterns, distributed energy resource (DER) adoption, electric vehicle (EV) charging trends, energy efficiency initiatives, and anticipated changes in land use or zoning. These inputs provide a comprehensive view of evolving demand drivers and support proactive planning aligned with regulatory expectations. This integrated approach enables informed planning and investment decisions that align with regulatory expectations for system reliability, operational efficiency, and long-term service sustainability.

  Through their continued communication with surrounding municipalities, Elexicon also identifies and plans for Externally-Initiated Plant Relocation and System Expansion initiatives, including activities relating to road relocations.

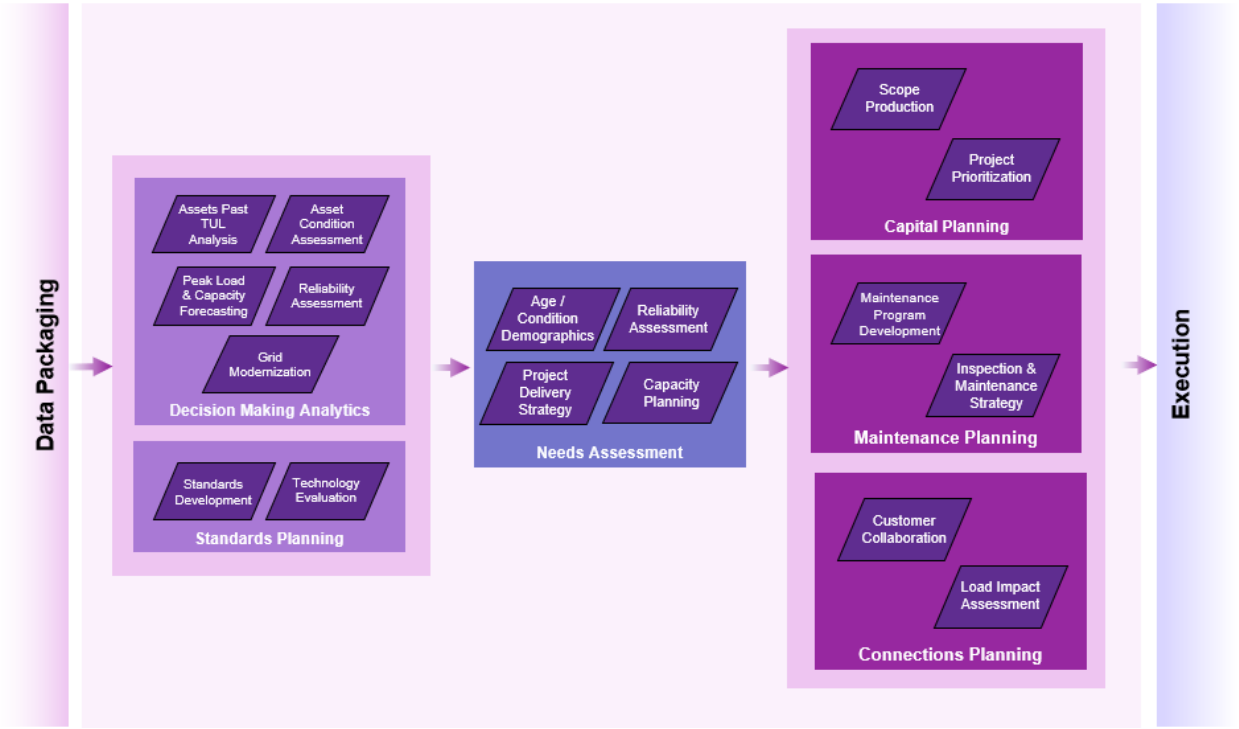
- **Grid Resilience:** Elexicon recognizes the persistent risks to system reliability that adverse and severe weather events can have on the distribution system, which highlights the importance of a grid that is resilient to such events. Through its Grid Modernization Plan, Elexicon will implement a series of investments informed by historical outage data, equipment condition assessments, and other parameters. These initiatives are designed to improve service delivery and meet evolving customer needs. Additionally, in alignment with the Ontario Energy Board's (OEB) Vulnerability Assessment and System Hardening (VASH) framework, Elexicon will be utilizing outputs from this analysis to prioritize investments in vulnerable areas to drive enhanced reliability, resiliency and customer value.

In conclusion, the integration of standards, structured reporting, and field data into Elexicon's planning framework creates a unified foundation for system planning. By embedding regulatory alignment, consistent data practices, and real-world asset insights into the process, Elexicon is equipped to make informed, strategic decisions that balance reliability, capacity, and long-term investment priorities.

1.3 System Planning

Following Data Packaging, System Planning represents the process of translating consolidated asset and system information into strategic investment decisions. This step evaluates system needs, asset risks, and performance drivers to develop coordinated capital and maintenance plans that align with Elexicon's operational objectives. It serves as the critical link between data preparation and execution within the AM Planning framework.

Figure 3: System Planning - AM Planning Process



1.3.1 Decision-Making Analytics

The Decision-Making Analytics stage leverages the consolidated data from the Data Packaging process to perform a series of system-wide analyses that inform Elexicon's capital and maintenance investment planning. This stage integrates multiple analytical frameworks to establish a comprehensive understanding of asset performance, condition, and system needs across the distribution network.

Collectively, these analyses provide a holistic view of Elexicon's distribution system, enabling the identification of emerging risks, system constraints, and opportunities for optimization. The outputs of this stage form the foundation for subsequent capital, maintenance and connections planning activities, where investment priorities and system needs are defined.

Table 1 below summarizes how the Decision-Making Analytics stage supports each investment category within the asset management framework.

Table 1: Summary of Analytical Framework Inputs by Investment Category

Investment Category	Typical Inputs to Needs Assessment
System Renewal	• Asset age demographics data, where each asset's calendar age is compared to its typical useful life (TUL) to identify those assets already past TUL, or assets that will exceed TUL by the end of the planning period (in this case, 2031). • Condition demographics data as generated by Elexicon's Asset Condition Assessment (ACA) framework, such that assets that are in Very Poor & Poor condition can be identified. • Historical reliability data including SAIDI, SAIFI, customers interrupted (CI) and customer hours interrupted (CHI) results, as well as number of outages, cause code trends and assessments of Major Event Days (MEDs) are brought together to identify emerging reliability challenges and issues. • Legacy equipment demographics and associated critical spares information relate to assets that no longer align with Elexicon's standard design practices and are increasingly affected by obsolescence and emerging safety and reliability concerns.

Investment Category	Typical Inputs to Needs Assessment
System Service	• Capacity and loading data, including capacity maps, capacity and load forecasting results, customer connection reviews and other inputs designed to provide short and long-term forecasts for customer and load growth within the service area. • Technology standards that provide guidelines for approved integration of emerging technologies, including CFCI's and other monitoring technologies. • Grid modernization plans, which leverages historical reliability data and load growth requirements to target investments in grid visibility, automation and control to transform the existing grid into a more modern, reliability, resilient and efficient system. • Voltage conversion short-term and long-term plans, providing insight into current-state performance of legacy voltage types. • Regional Planning Process and associated outputs, which provide broader regional planning requirements between Elexicon, Hydro One and adjacent utilities.
System Access	• Advanced metering infrastructure (AMI) plans, including short-term and long-term roadmaps detailing future metering requirements, including front-end metering and back-end communications requirements. • Customer requests, including short-term and long-term development requests, providing insight into customer growth, the type of growth (e.g. residential, commercial, industrial) and the nature of customer requests. • Third-party coordination & requests, including short-term and long-term development requests with municipalities and transit systems, providing insight into third-party planning requirements and the nature of these requests.
General Plant	• Fleet & facilities demographic and performance data, providing insight into the overall performance and reliability of fleet and facilities infrastructure. • Short-term and long-term tools & equipment requirements, providing insight into future tools and equipment requirements. • IT system demographic and performance data, providing insight into current-state performance of IT systems, as well as identifying systems reaching EOL or obsolescence.

1

2 The following subsections describe the analytical methodologies applied within the Decision-Making

Analytics stage, including the Asset Condition Assessment (ACA), Assets Past Typical Useful Life (TUL) Analysis, Load and Capacity Forecasting, and Reliability Assessment. Each methodology provides distinct insights that collectively guide Elexicon's risk-informed, data-driven investment planning.

Assets Past Typical Useful Life (TUL) Analysis

Elexicon performs an Assets Past Typical Useful Life (TUL) analysis to assess age-related risks across its asset base and identify infrastructure that is approaching or has surpassed its expected typical useful life. The purpose of this analysis is to generate risk insights that complement the results of the Asset Condition Assessment (ACA) and provide a broader understanding of lifecycle performance trends across the distribution and substation portfolios. The Assets Past TUL analysis is updated yearly.

This analysis evaluates assets against their Typical Useful Life (TUL) values, which have been defined for each asset class and derived from the Asset Depreciation Study prepared for the Ontario Energy Board (July 2010)[1]. Each asset is compared against its respective asset class TUL, and the results are categorized into three primary groups:

- Assets that have already exceeded their TUL;
- Assets that will exceed their TUL within the next five years; and
- Assets that remain within their expected TUL.

This analysis produces an age-based demographic profile of Elexicon's asset population, providing a high-level view of renewal pressures across the system. When integrated with ACA results, the Assets Past TUL analysis allows Elexicon to differentiate between age and condition when evaluating failure risk, thus improving the targeting and prioritization of renewal investments.

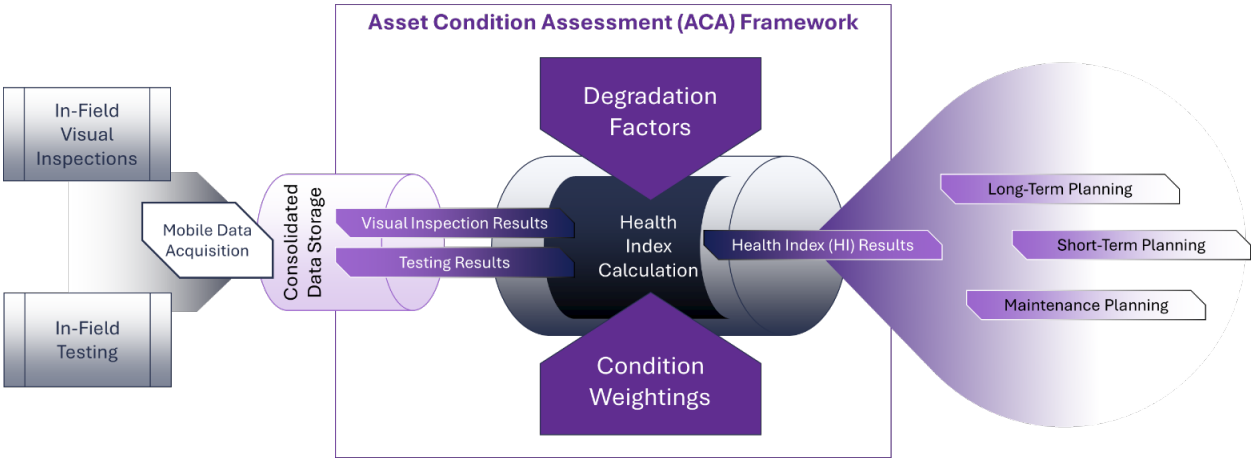
Detailed assets past Typical Useful Life (TUL) results are presented in Exhibit 2B - Tab 3 - Schedule 2.

Asset Condition Assessment

[1] Kinectrics, "Asset Depreciation Study for the Ontario Energy Board", (July 2010).

The Asset Condition Assessment (ACA) framework leverages in-field inspection and testing data to quantify the health of each asset and support risk-informed decision-making. Figure 4 illustrates Elexicon's ACA Framework. The ACA analysis is updated annually.

Figure 4: Elexicon's Asset Condition Assessment Framework



In-Field Visual Inspections & Testing: In-field visual inspection and testing data are captured through mobile or electronic devices and processed to calculate health index (HI) scores. The frequency of visual inspections and testing activities varies by asset class and is established in accordance with Elexicon's internal maintenance standards and the requirements outlined in the Ontario Energy Board's Distribution System Code (DSC), as well as other applicable regulatory and safety standards.

Degradation Factors: Within the ACA framework, degradation factors represent the condition parameters that influence asset deterioration and eventual failure. Degradation factors will be specific to each asset class and will typically include results from visual inspection and maintenance activities.

Where an asset possesses greater deterioration with respect to a given degradation factor, it will receive the lowest possible degradation factor score, whereas an asset with less deterioration will receive a higher degradation factor score. Examples of degradation factors include remaining structural strength within a wood pole to assess overall internal strength and health within the pole, or the results from infrared (IR) thermographic inspections, used to detect thermal anomalies in equipment such as distribution transformers, switchgear, and cable terminations.

Condition Weightings: A weight is assigned to each degradation factor to indicate its relative influence on the overall health and resulting HI score of the asset. The weighting applied to a given factor depends on the parameter type (e.g., testing versus visual inspection) and the other factors included in the HI calculation.

Since testing results can be more quantitative in nature, these results, such as remaining strength, may be weighted more heavily when compared to visual inspection parameters. Certain parameters may also be given a greater weight where it is known that they will result in a greater overall health impact to the asset as a whole. An example would include oil leaks within a padmount transformer, since leaks can lead to further contamination (e.g. water and moisture ingress) to the dielectric oil within the transformer tank.

HI Result: Degradation factors are scored based on visual inspection and testing results. Based upon Elexicon's ACA framework, the highest numerical score of 4 will be assigned to degradation factors where the best possible condition (pertaining to that degradation factor) is observed, while the lowest numerical score of 0 will be assigned to degradation factors where the worst possible condition is observed. The final HI score is calculated by combining the individual degradation scores and their respective weightings, divided by the maximum possible score, to produce a normalized value representing the overall asset health. The ACA process produces a HI score on a scale from 0% to 100% for each asset, representing its overall condition. New assets typically have an HI of 100%, which decreases over time as degradation occurs.

Table 2: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
30-50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

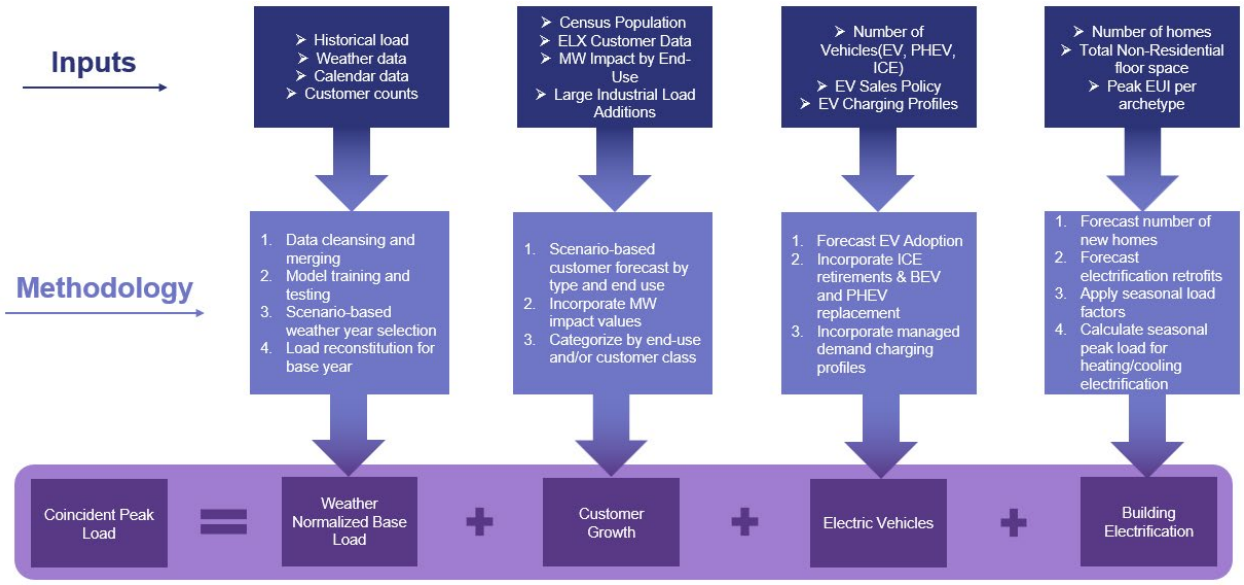
This ACA process is executed annually, accounting for the newest asset registry, inspection and testing data. The resulting outputs are integrated into the system planning process, where they support informed decision-making. These insights guide the development and execution of capital and maintenance programs, ensuring that identified risks are addressed proactively. Refer to Exhibit 2B – Tab 3 – Schedule 2 - Appendix B for the ACA report, which outlines the degradation factors, applied weightings, and results.

Peak Load & Capacity Forecasting

Historical demand data and system performance are combined with demographic, economic, and policy-based projections to develop a forward-looking view of system loading under a range of scenarios. Weather normalization techniques are applied to remove short-term anomalies, ensuring the forecast reflects sustainable trends in customer and community growth. The Peak Load & Capacity Forecast is

updated on an ongoing basis when substantial updates are received from the municipalities Elexicon serves. A complete update is performed yearly. Figure 5 below outlines Elexicon's Load & Capacity Forecasting process.

Figure 5: Elexicon's Peak Load & Capacity Forecasting process



These forecasts are then applied in the Capacity Planning stage to evaluate the system's ability to meet projected demand. Each substation's transformer capacity and downstream feeder capacity are compared against the forecasted load to identify emerging capacity constraints. This assessment provides early visibility into areas where additional substation supply or distribution capacity will be required to maintain reliability and service quality.

Capacity constraints identified through this analysis fall into two categories:

- Insufficient Substation Supply Capacity – when the upstream supply available is inadequate to meet projected demand.
- Insufficient Distribution System Capacity – when the downstream capacity from a substation is insufficient to serve forecasted load.

The following subsections describe the key components of this process in greater detail, beginning with the development of the System Peak Load Forecast, which outlines how customer growth, electrification, and weather normalization are used to project future demand across Elexicon's service territory. This is followed by the Capacity Planning stage, which applies the forecast to evaluate available system capacity and identify areas requiring investment.

System Peak Load Forecast

The System Peak Load Forecast provides a comprehensive outlook of electricity demand across Elexicon's service territory and forms the foundation for identifying future capacity needs. The forecast covers the entire Elexicon service area and considers both summer and winter peak seasons, the results of the forecast from 2025 to 2031 through the rate period are shown in Exhibit 2B - Tab 3 - Schedule 2.

To accurately represent system demand, the forecast was developed through four sub-forecasts that capture the key drivers of load growth. Each sub-forecast addresses a specific component of system demand, and the results are aggregated to produce a combined system peak load forecast.

The four sub-forecasts incorporated into the model are:

1. Weather-Normalized Baseload ("Load Floor")

The Weather-Normalized Baseload represents the foundational component of the system peak load forecast and reflects the existing peak electrical demand under typical weather conditions. This baseline was derived from Elexicon's historical metering data and serves as the reference point for projecting future growth in system demand. Historical daily peak loads from 2014 to 2023 were analyzed for both summer and winter seasons to capture variations in temperature-driven demand patterns.

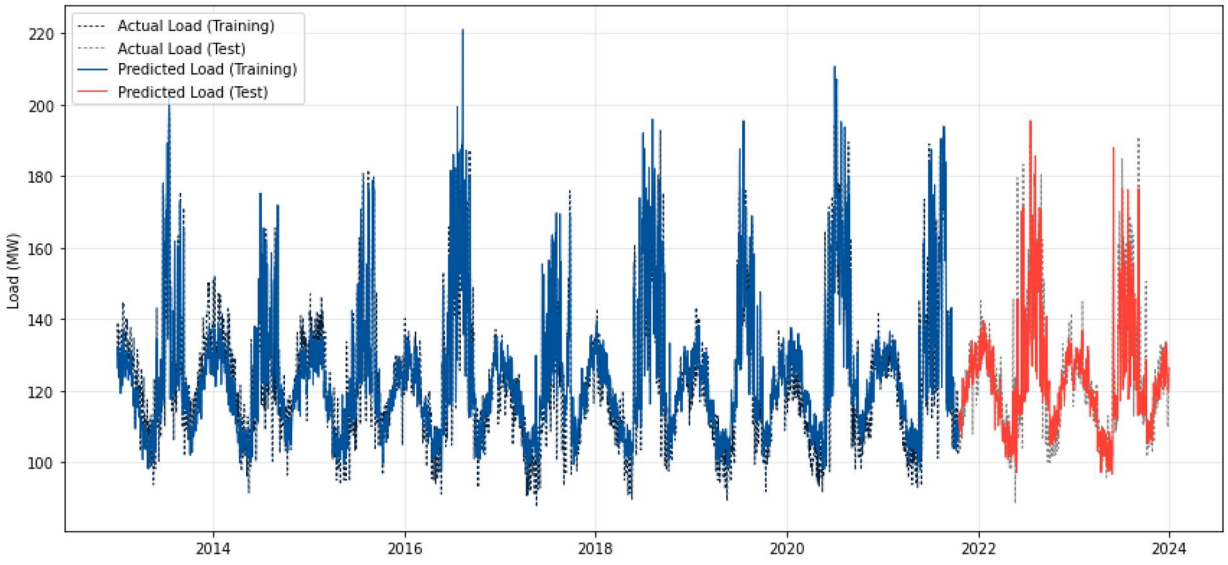
To normalize these data, a multivariate linear regression model was developed to correlate load with weather variables:

- Cooling Degree Days (CDD)
- Heating Degree Days (HDD)
- Seasonal, monthly, and weekday effects

- Holidays, solar eclipses, and COVID-19 impacts

The regression model was validated using statistical performance indicators such as the coefficient of determination (R^2) and Mean Absolute Percentage Error (MAPE) to ensure reliability. Both validation methods demonstrated robust accuracy, supported by the close alignment between the training and testing periods. The validation for the Whitby region load data is shown in Figure 6. The model was trained on historical peak load data from 2014 to 2021 (the training period) and then tested by predicting peak loads for 2022–2023 (the testing period) and comparing against the actuals.

Figure 6: Predicted and Actual Load from Regression Model on Training and Test Sets for Whitby



Once normalized, the baseline load was adjusted to account for different weather severity conditions to assess potential system stress levels. Three representative weather scenarios were used to model future peak conditions:

- **P90 (Extreme Weather):** Represents conditions at the 90th percentile, meaning there is only a 10% chance that demand will exceed this level. These scenarios correspond to high-temperature or low-temperature extremes resulting in maximum demand.
- **P50 (Normal Weather):** Represents the 50th percentile, or the median expected demand. This reflects average weather conditions typically observed across the service area.

- **P10 (Mild Weather):** Represents the 10th percentile, meaning there is a 90% chance demand will be higher than this level. These scenarios correspond to milder conditions associated with reduced heating or cooling demand.

For capacity planning purposes, the P90 (Extreme Weather) scenario was selected to ensure that system adequacy is assessed under the most demanding but credible conditions. This approach provides a conservative basis for planning, ensuring that Elexicon's infrastructure can accommodate extreme temperature events that have a higher likelihood of driving system peaks and potential capacity constraints.

2. Customer Growth

A bottom-up approach was used to estimate future demand arising from residential, commercial, and industrial developments. The forecast incorporates municipal planning data, demographic projections, and committed connection requests.

Residential:

- Based on growth forecasts for residential development compiled from municipal planning documents and studies:
    - Durham Region: Based on the Envision Durham Draft Official Plan[2].
    - Belleville: Based on the Belleville Population, Housing and Employment Growth Forecast[3].
    - Gravenhurst: Based on the Gravenhurst Growth Management Strategy[4].
    - Port Hope: Based on the Northumberland County Official Plan[5].

[2] Durham Region, "Envision Durham – Draft New Regional Official Plan", (February 2023).

[3] Watson & Associates, "Population, Housing, and Employment Growth Forecast Update – City of Belleville", (December 21, 2022).

[4] Hemson Consulting, "The District of Muskoka Forecast & Growth Allocation Report", (2019).

[5] Northumberland County, "Northumberland County Official Plan", (2016).

- Residential archetypes (e.g., single-detached, row houses) were developed using Statistics Canada Census data (2006–2021).
- Average household energy consumption data from Statistics Canada and Elexicon's Ontario Energy Board (OEB) Yearbook were converted to peak load using historical regional load factors.

Commercial and Industrial:

- Business and employment statistics from Statistics Canada were used to establish business-to-employee ratios by district and sector.
- Employment growth forecasts from each region were translated into business counts and mapped to sector-specific load intensities (e.g., retail, manufacturing):
    - Durham Region: Based on the *Envision Durham Draft Official Plan*[2].
    - Belleville: Based on the *Belleville Population, Housing and Employment Growth Forecast*[3].
    - Gravenhurst: Based on the *Gravenhurst Growth Management Strategy*[4].
    - Port Hope: Based on the *Northumberland County Official Plan*[5].
- Load per business type was derived from Elexicon's OEB Yearbook data to distinguish industrial and commercial demand profiles.
- External to the macro forecasted growth, committed connection requests[6] for large upcoming commercial & industrial loads were also incorporated.

To account for uncertainty in long-term development patterns and economic conditions, a sensitivity analysis was performed on the Customer Growth forecast. The analysis evaluated how variations in population growth, housing development rates, and employment expansion may influence system peak demand over the planning horizon.

[6] Committed loads are classified as loads where Elexicon and the customer have signed an Offer-to-Connect or Memorandum of Understanding to connect the agreed upon load.

Sensitivity Analysis:

A sensitivity analysis was conducted to evaluate how varying rates of customer growth could influence peak demand across Elexicon's service territory. The analysis accounts for the uncertainty inherent in long-term development patterns.

Three growth scenarios were developed to represent a range of potential outcomes:

- **Low Growth Scenario:** 50% of the projected residential homes are developed, and 50% of the projected Commercial and Industrial (C&I) business counts materialize within the forecast period.
- **Medium Growth Scenario:** 75% of the projected residential homes are developed, and 75% of the projected Commercial and Industrial (C&I) business counts materialize within the forecast period.
- **High Growth Scenario:** 100% of the projected residential homes are developed, and 100% of the projected Commercial and Industrial (C&I) business counts materialize within the forecast period.

For capacity planning purposes, the High Growth Scenario was selected to meet 100% of the projections outlined in the various municipal and regional growth plans. These scenarios were reviewed during municipal coordination meetings with each respective municipality, all of which agreed with Elexicon's rationale for selecting this growth scenario. By adopting this scenario, Elexicon ensures that its infrastructure planning is based on realistic and appropriate assumptions, enabling it to meet all potential demand should it materialize.

This scenario reflects the ongoing growth trajectory across Elexicon's service territories, driven by intensified residential construction, mixed-use urban developments in greenfield areas, and a surge in committed large customer projects. It also aligns with provincial and municipal policy objectives that emphasize housing acceleration and economic expansion.

3. Building Electrification

The Building Electrification forecast incorporates anticipated increase in peak load demand from the transition of building heating, cooling, and water-heating systems from fossil fuels to electricity. This analysis reflects both new construction buildings built to higher efficiency standards and retrofits of

existing buildings that are converting to electric technologies such as heat pumps and electric water heaters.

To estimate these impacts, residential and commercial forecasts were developed using municipal energy plans and national energy-intensity data sources from the Natural Resources Canada (NRCan) Comprehensive Energy Use Database.

Residential:

- Retrofit targets are based on the expected rate of residential electrification retrofits and derived from available municipal energy plans.
- Incorporates retrofit and new net-zero construction goals by building archetype.
- End-Use Intensity (EUI) represents the average energy consumption per household by end-us category, including space heating, water heating, and other major appliances.
- Coefficient of Performance (COP) reflects the efficiency of residential electric heating and water-heating systems and is used to convert thermal demand into equivalent electrical load for the electrification forecast.

Commercial:

- Developed using municipal energy plans and Natural Resources Canada data.
- Accounts for floor-space targets for both new and retrofit projects.
- EUI represents the average energy consumption per unit of floor area across commercial and industrial facilities.
- COP for commercial applications represents the efficiency of electric heating and water-heating systems.

Sensitivity Analysis

A sensitivity analysis was conducted to capture the uncertainty surrounding the rate of building electrification adoption. Three scenarios were developed:

- **Low Scenario:**
  - Residential
    - Retrofit: Maintains the 2025 building electrification targets throughout the forecast period, derived from available municipal energy plans.
    - New Build: Aims for 100% electrification by 2035.
  - C&I:
    - Retrofit: Maintains the 2025 building electrification targets throughout the forecast period, derived from available municipal energy plans.

New build: Net-zero targets from available municipal energy plans delayed by 5 years.

- **Medium Scenario:**
  - Residential:
    - Retrofit: Applies the targets from available municipal energy plans.
    - New Build: Aims for 100% electrification by 2035.
  - C&I:
    - Retrofit: Applies the retrofit targets from available municipal energy plans delayed by 5 years.
    - New build: Net-zero targets from available municipal energy plans delayed by 5 years.
- **High Scenario:**
  - Residential:
    - Retrofit: Applies the targets from available municipal energy plans.
    - New Build: Aims for 100% electrification by 2030.

- C&I:
  - Retrofit: Applies the targets from available municipal energy plans.
  - New build: Applies the targets from available municipal energy plans.

For capacity planning purposes, the High Scenario was selected to meet 100% of the projected electrification impacts outlined in available municipal energy plans and federal growth and energy transition plans. These scenarios were reviewed during municipal coordination meetings with each respective municipality, all of which agreed with Elexicon's rationale for selecting this scenario. By adopting this approach, Elexicon ensures that its infrastructure planning is based on realistic and appropriate assumptions, enabling it to meet all potential electrification-related demand.

This approach represents prudent planning by capturing the upper range of potential heating electrification, which significantly influences both winter and summer peak demand.

4. Electric Vehicles (EVs)

The EV forecast estimates peak load impacts associated with the growing adoption of electric vehicles. The model considers vehicle population, EV sales targets and adoption rates and the load impact per EV.

Vehicle Population:

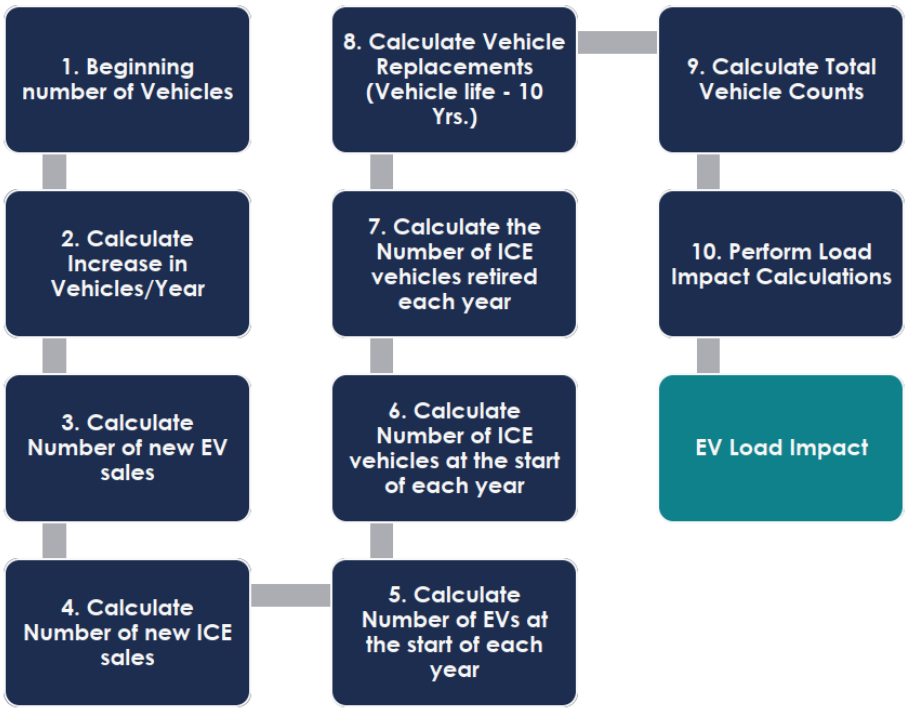
- Determined using municipal population forecasts and vehicle-per-capita ratios to estimate the growth of light-duty vehicle (LDV) ownership.
- Medium- and heavy-duty (MD/HD) EV adoption was estimated based on business counts for each region taken from the commercial customer growth forecast.
- Historical total vehicle (internal combustion engine and electric vehicle) counts for Ontario, and the regions Elexicon serves were taken from the Ministry of Transportation (MTO).

EV Sales Target and Adoption Rates:

EV target percentages of new electric vehicle sales each year for LDV based on Federal Policy where adoption rates were modeled using an S-curve.

- Retirement rates for internal combustion engine (ICE) vehicles were assumed at to be retired every 10 years.

Figure 7: Process of Calculating EV Load Impact



Load Impact per EV:

- Peak charging demand assumptions based on Dunsky Energy for Natural Resources Canada for LDV[7].
- Peak charging demands for MDV/HDV were taken from a study conducted by Lawrence Berkley Labs in California[8].

[7] Natural Resources Canada, "Electric Vehicle Charging Infrastructure for Canada", (n.d.).Available: Electric Vehicle Charging Infrastructure for Canada - Natural Resources Canada
[8] Lawrence Berkley National Laboratories, Individual Charging Profiles in 2030, 2022.

Sensitivity Analysis:

A sensitivity analysis was conducted to capture the uncertainty associated with future EV adoption, which is influenced by federal and provincial policy timelines, technology availability, infrastructure readiness, and consumer uptake. Three adoption scenarios were developed for both LDV and MDV & HDV:

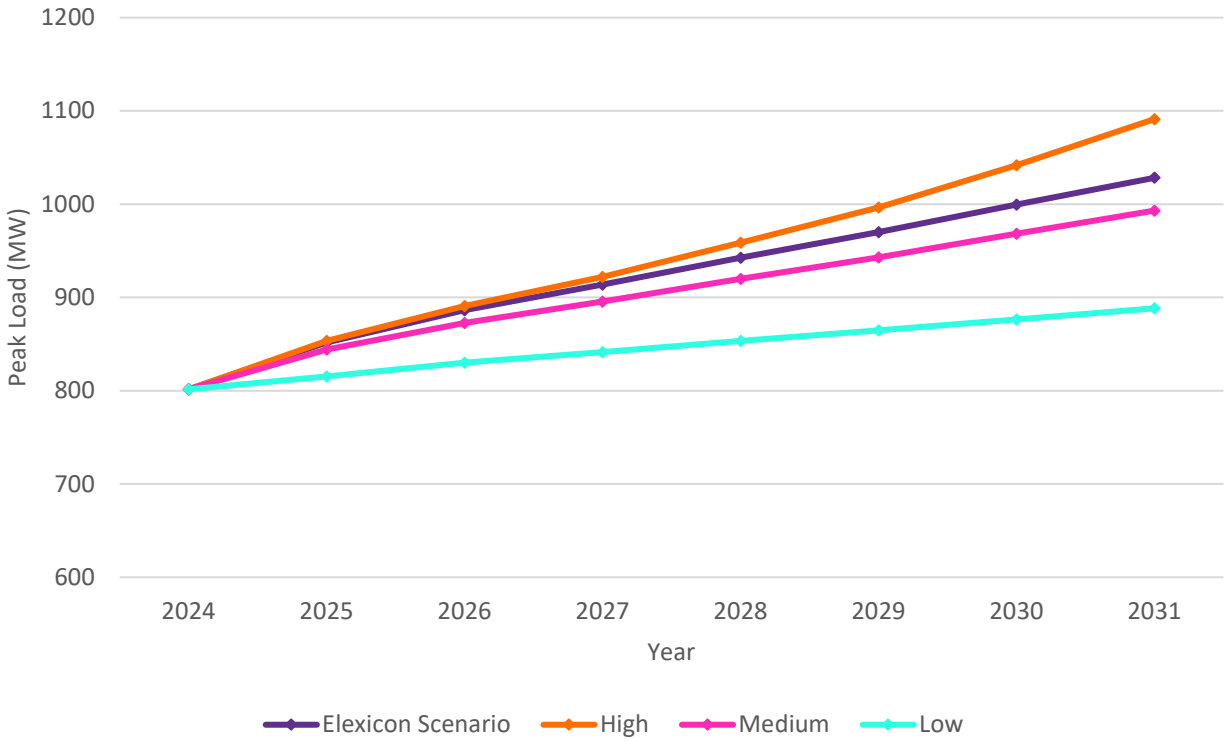
- **Low Scenario (Business-as-Usual):** Represents incremental EV adoption under current provincial trends without additional policy acceleration. The Business-As-Usual (BAU) scenario uses a linear model based on historical Ontario data.
- **Medium Scenario (Delayed Policy):** Reflects a five-year delay in achieving federal ZEV targets — 100% of new light-duty vehicle sales by 2040 and 100% of medium- and heavy-duty vehicle sales by 2045. This represents a moderate adoption trajectory consistent with infrastructure expansion and market behaviour.
- **High Scenario (Federal Policy):** Assumes achievement of Canada's ZEV sales targets—100% of new light-duty vehicle sales by 2035 and 100% of medium- and heavy-duty vehicle sales by 2040.

For capacity planning purposes, the Medium Scenario was selected. This scenario reflects realistic and balanced expectations of EV market growth in Ontario, accounting for gradual infrastructure development, evolving consumer preferences, and the current pace of policy implementation. Similar to the previous sections, these scenarios were reviewed during municipal coordination meetings with each respective municipality, all of which agreed that this scenario captured meaningful load growth from transportation electrification without overstating short-term impacts on system capacity.

In summary, the four inputs – Weather-Normalized Baseload, high scenario Customer Growth, high scenario Building Electrification, and medium scenario Electric Vehicles – were aggregated into an Elexicon Scenario (described above in each input) to produce a consolidated System Peak Load Forecast, shown in Figure 8. This System Peak Load Forecast represents the total anticipated load demand across Elexicon's service territory up to the end of 2031 through the DSP planning period. This integrated forecast captures the combined influence of demographic growth, electrification trends, and evolving consumer behaviours, providing a comprehensive view of how system loading is forecasted to evolve. The resulting projections

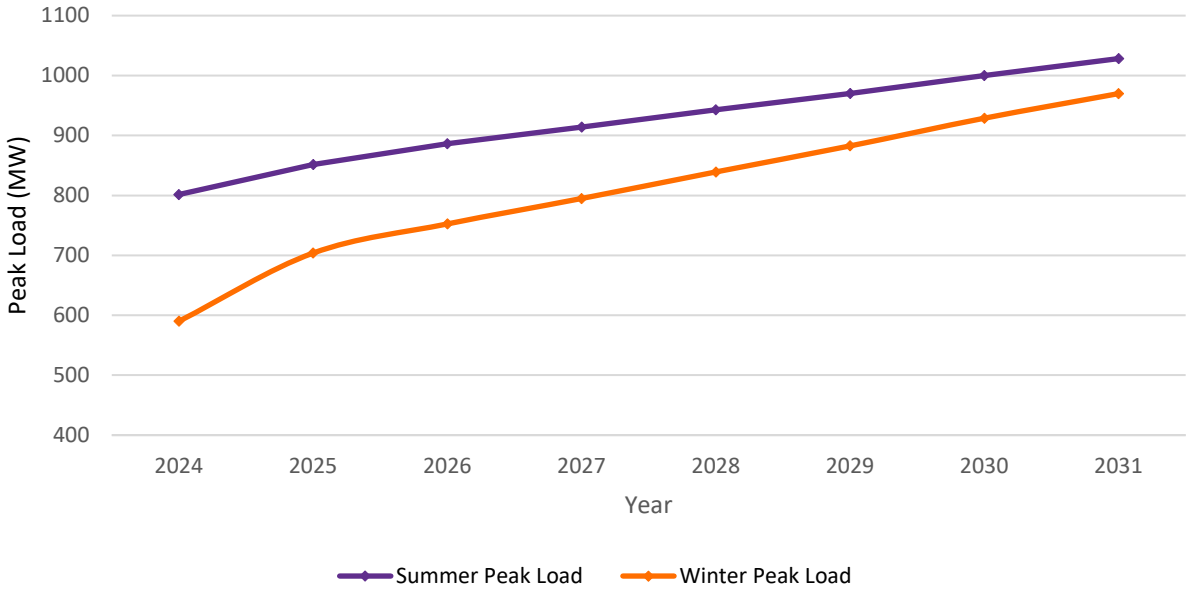
form the analytical foundation for Capacity Planning, where forecasted peak demand is compared against system and equipment ratings to identify when and where capacity constraints may occur.

Figure 8: System Peak Load Forecast Scenarios (P90 Summer) 2024-2031



Elexicon is currently a summer peaking utility across the majority of its service territory. As shown in Figure 9, the System Peak Load Forecast indicates that winter peak demand is increasing at a higher annual rate due to the continued electrification of space and water heating, leading to a progressive alignment of winter and summer peaks. This shift toward a dual-peaking system highlights the importance of forward-looking capacity planning to ensure Elexicon's distribution system remains capable of meeting peak demand under extreme weather conditions. The results of this forecast provide the foundation for subsequent capacity assessments, guiding investment decisions to maintain system adequacy, reliability, and alignment with long-term growth and electrification trends.

Figure 9: System Peak Load Forecast Summer vs. Winter 2024-2031



Reliability Assessment

Elexicon continuously evaluates the reliability performance of its distribution system to identify emerging risks, understand the underlying causes of interruptions, and guide future investment decisions. A Reliability Assessment forms a core component of Elexicon's Decision-Making Analysis framework, providing continuous data-driven insights into ongoing system performance trends and areas requiring targeted improvement.

Reliability performance is primarily assessed through key reliability indicators, including SAIDI and SAIFI. Refer to Exhibit 2B - Tab 2 - Schedule 2 for Elexicon's historical reliability information. Feeder-level analysis is further enhanced through the identification and review of Worst Performing Feeders (WPFs) and Feeders Experiencing Sustained Interruptions greater than seven (FESI-7), which is measured excluding MED's, LOS and Scheduled outages (SO). Top 10 WPFs are determined annually based on a combination of SAIDI, SAIFI, and number of sustained interruptions, with adjustments made to exclude MEDs and LOS. Each WPF is subject to detailed root-cause analysis to determine predominant outage causes, such as defective equipment, vegetation contact, animal interference, or operational constraints. For Loss of

Supply outages, Elexicon continuously engages with the transmitter to review reliability issues to improve supply point reliability across its service areas.

These insights are used to identify high-risk feeders, recurring equipment issues, and geographic clusters of poor reliability performance. The results directly inform Reliability Planning activities within Capital and Maintenance Planning.

Grid Modernization

The electricity grid is undergoing a transformative shift driven by electrification, the integration of Distributed Energy Resources (DERs), and the growing need for enhanced resiliency in the face of climate change. To maintain reliable service through these current and anticipated changes, Elexicon must continue investing in grid modernization technologies. The Grid Modernization plan focuses on strengthening the grid's near-term resiliency, reliability, and adaptability through targeted investments in four focus areas of smart devices, operational technology, distributed energy and electrification, and enhanced data analytics. The Grid Modernization plan is continuously updated in alignment with the strategy document. Further details on Elexicon's Grid Modernization Plan can be found in Exhibit 2B - Tab 3 - Schedule 2 - Appendix A.

Modernizing the distribution system involves improving automation and fault management using smart devices, such SCADA-enabled switches, communicating fault current indicators (CFCIs), AMI 2.0, and self-resetting fuses. These technologies provide real-time insights into grid performance and operations and enhance reliability through improved restoration times during system events.

In the Grid Enhancements program, as part of the substation modernization segment, Elexicon is advancing a data-driven Asset Performance Management (APM) approach by leveraging real-time monitoring, condition sensors, and intelligent electronic devices (IEDs). This enables proactive maintenance, improves visibility into asset health, and enhances system reliability and resiliency across substations.

Investments in distribution capacity and reliability enhancements aim to alleviate capacity constraints while addressing known reliability risks. Initiatives such as replacing undersized conductors, installing animal guards, and deploying lightning arrestors will improve system reliability. Additionally, new

substations and feeder upgrades will support future load growth, resolve capacity constraints, and create new pathways for power routing.

This added flexibility supports planned outages and contributes to a more reliable and resilient grid. Vulnerability of the electrical grid to climate change and adverse weather events is another aspect that requires system hardening to withstand these events to sustain a stable power supply. In alignment with the OEB's Vulnerability Assessment and Storm Hardening (VASH) framework, Elexicon will identify areas within the grid for strategic investment opportunities to modernize and harden the grid to mitigate risks and customer impacts. Together, these initiatives position Elexicon to deliver reliable, resilient, and intelligent grid services, ensuring the organization can effectively adapt to future challenges and continue meeting evolving customer needs.

1.3.2 Standards Planning

Elexicon continually reviews, updates, and develops its construction and design standards to ensure that all assets are installed, operated, and maintained in a safe, efficient, and consistent manner. Standards Planning forms a key part of Elexicon's broader Asset Management Process, linking technical requirements with long-term planning, maintenance, and capital delivery functions.

Standards Development

Elexicon's standards are developed and maintained through a structured process that involves cross-functional input from Engineering, Operations, and Planning teams. This process ensures alignment with applicable regulatory requirements, industry best practices (e.g., CSA, IEEE), and internal safety procedures. Periodic reviews are conducted to incorporate lessons learned from field experience, emerging risks, and technological advancements.

Technology Evaluation

As part of this process, Elexicon conducts Technology Evaluation and Integration activities to assess new materials, equipment, and emerging technologies for potential adoption. Each new technology is reviewed for safety, compatibility, and performance through detailed engineering analyses, including short-circuit, grounding, arc-flash, protection and coordination, and power-quality studies. Technologies that

demonstrate clear operational, reliability and resiliency benefits are standardized for broader system use and integrated into Elexicon's construction and maintenance practices.

1.3.3 Needs Assessment

Needs Assessment represents the process through which Elexicon translates analytical insights from the Decision-Making Analytics stage into actionable, system-level investment needs. This stage forms the bridge between analytical assessment and system level investment planning, where data-driven insights are utilized to determine where reinforcements, replacements, and upgrades are required across the distribution and substation systems to maintain safe, reliable, and efficient service delivery.

Key Decision-Making Analytics discussed above that inform the Capital Planning process include:

- Assets Past Typical Useful Life (TUL) Analysis
- Asset Condition Assessment (ACA)
- Load Forecasting & Capacity Planning
- Reliability Assessments

These analytical results are evaluated collectively to establish a system-wide view of asset risk and investment need. Elexicon prioritizes areas requiring intervention by considering asset criticality, system constraints, operational risks, and customer growth drivers. The outcome of this process is a defined set of system needs and investment themes that inform subsequent stages of Project Planning, where individual projects and programs are scoped, costed, and scheduled for execution.

1.3.4 Capital Planning

The Capital Planning stage represents the process through which Elexicon transforms identified system needs from the System-Wide Needs Assessment into actionable, executable scopes. This stage ensures that investment priorities are defined, scoped, and validated to enable efficient project delivery and prudent capital expenditure.

Focus Areas of Capital Planning: Elexicon's Capital Plan is designed to balance long-term system renewal, modernization, and growth while maintaining affordability for customers. The key focus areas include:

- Addressing system capacity needs to accommodate existing and future customer demand;
- Enhancing reliability by replacing end-of-life and deteriorated assets, and;
- Modernizing the grid to enhance system visibility, operability, and resiliency.

These focus areas ensure that investments are strategically aligned with corporate objectives, regulatory expectations, and system performance outcomes. Capital Planning activities are coordinated across multiple departments including Asset Planning and System Engineering, Program Delivery, Design and Construction, System Control Centre (SCC), and Finance to ensure consistency with regulatory requirements, IRRPs, RIPs, and Elexicon's long-term system performance objectives. This integrated planning approach enables Elexicon to proactively manage infrastructure renewal, optimize capital deployment, and ensure that long-term investment pacing remains sustainable and achievable.

Although project execution is addressed in later stages of the planning process during the development of the execution work packages, Elexicon considers delivery feasibility and resourcing requirements during the Capital Planning stage to ensure that identified investments are realistic and executable within the planning window.

Key considerations include:

- Availability of internal and external construction resources;
- Timing of material procurement and long-lead equipment;
- System outage and switching constraints required for project execution; and
- Annual pacing of work to align with financial and operational capacity.

Incorporating delivery considerations at this stage ensures that capital investments can transition smoothly from planning to implementation, supporting consistent attainment of Elexicon's annual Capital Execution Work Program (EWP).

In support of this Distribution System Plan, Elexicon examined three different investment scenarios where applicable, for the 2027 to 2031 DSP planning period:

- **Needs-Based:** This investment scenario is designed to prioritize the needs of the system within the 2027-2031 filing period through an accelerated investment program.
- **Balanced:** This investment scenario is designed to balance the needs of the system with customer rate affordability through a strategically paced investment program.
- **Low:** This investment scenario is designed to prioritize rate impacts above the needs of the system, which leads to increasing asset risks, reliability degradation and capacity constraints through the 2027-2031 period.

In summary, Elexicon's Capital Planning process is inherently collaborative and cross-functional, drawing on input from multiple departments across the organization. Through this coordinated approach, Elexicon identifies and prioritizes system needs in a manner that balances technical analysis, operational experience, financial prudence, and customer priorities. The result is a capital plan that is evidence-based, strategically aligned, and optimized to meet both local and regional system needs in a safe, reliable, and cost-effective manner.

Scope Production

Elexicon develops discrete project scopes to address capital investment needs. Each scope defines a specific investment need, typically at the asset or geographic level, and serves as the foundation for the utility's capital program.

Scope development follows a structured workflow to ensure technical validity, consistency, and alignment with investment priorities. The process begins with an Initiation phase, where each potential project is assigned a unique identifier and recorded in Elexicon's internal planning tracker.

Each proposed scope undergoes a feasibility review to assess deliverability, alignment with standards, and consistency with corporate and regulatory objectives. Scopes deemed non-viable are withdrawn, while feasible scopes proceed to documentation, including technical justification and budgetary estimates.

A typical Scope Document includes:

- Project identification Details
- Project overview and justification
- Primary and secondary drivers
- Scope of work – defined activities, design boundaries, and schematic references
- Preliminary cost estimate – itemized by materials, labour, and contingency
- Customer preference alignment – referencing survey results and engagement outcomes
- Criticality score and impacted customers – quantifying benefit and system impact
- Options analysis – summary of alternatives considered and rationale for selection
- Long-lead material requirements – expected delivery timelines for key components; and
- Approvals and sign-off

This standardized structure ensures that each capital project is well-defined, justified, and ready for prioritization and inclusion in the Capital Execution Work Program (EWP).

Project Prioritization

As part of the Capital Planning stage, Elexicon prioritizes projects to ensure that investments are directed toward areas of highest need, balancing risk, reliability, customer impact, and regulatory compliance. Project prioritization is guided by a structured criticality-based framework that integrates both mandatory and risk-based criteria. Prioritization of projects within the investment categories follow the approach below.

- **System Access:** Prioritized as mandatory to accommodate new customer connections or third-party requirements. These projects are typically non-discretionary and driven by external demand or regulatory obligations.

- **System Renewal:** Prioritized based on criticality scoring that considers the probability and consequence of asset failure. The framework incorporates metrics such as asset condition assessments, customer count and type, safety exposure, operational risk, functional obsolescence and outage performance. For substation assets, prioritization additionally considers redundancy and loading limitations. Projects addressing the highest-risk assets or those that mitigate

significant reliability or safety concerns are advanced first. To ensure consistency, Elexicon applies a quantitative scoring methodology consisting of two key components:

1. **Impact Assessment (Consequence of Failure)**: Evaluates financial, reliability, safety, and environmental dimensions using a weighted matrix. Each factor is scored to produce an overall Impact Score (IS).

2. **Probability Assessment (Likelihood of Failure):** Considers asset condition, historical performance, and presence of legacy or non-standard assets to determine a Probability Score (PS).

The Criticality Score (CS), derived from the combination of IS and PS, provides a standardized basis for ranking and sequencing renewal projects. This enables Elexicon to allocate resources to initiatives that deliver the greatest value in terms of risk reduction, customer benefit, and system reliability, while ensuring alignment with available budgets, regulatory requirements, and stakeholder input.

- **System Service:** Prioritized based on contribution to improving reliability, resiliency, automation, visibility, and overall system efficiency. For substation growth projects, prioritization additionally considers the load forecast and capacity analysis to address areas approaching or exceeding capacity. For voltage conversion projects, prioritization is based on a combination of technical and operational criteria, including feeder capacity utilization, the condition and age of infrastructure, risk of failure, safety concerns, and redundancy limitations.

- **General Plant:** Prioritized based on operational necessity, safety, and enablement of core business functions. Criteria include end-of-life condition, compliance with safety or regulatory standards, and the asset's criticality to maintaining day-to-day operations and supporting field work.

Elexicon's project prioritization process ensures that capital investments are selected and sequenced based on objective, risk-informed criteria. By applying a standardized framework, Elexicon ensures that projects addressing the highest system risks, customer impacts, and operational constraints are advanced first.

1.3.5 Maintenance Planning

Maintenance Program Development

In parallel with capital planning, Elexicon conducts maintenance planning to sustain the performance and reliability of in-service assets and to prevent premature asset failure. Elexicon's maintenance planning framework is primarily driven by the requirements of the Distribution System Code (DSC), applicable regulatory obligations, and equipment manufacturer recommendations. These requirements establish the minimum inspection, testing, and maintenance standards necessary to ensure the continued safety, reliability, and performance of distribution system assets.

While maintenance activities are largely prescriptive and compliance-based, Elexicon supplements these requirements with targeted prioritization based on asset condition, location, criticality, and historical performance data. In case of substations, where operational experience or asset health indicators suggest increased risk of failure, Elexicon may increase the maintenance frequency or scope to sustain asset life and mitigate reliability or safety concerns.

Inspection and Maintenance Strategy

Elexicon's maintenance programs includes activities such as visual inspections, patrols, Co2 cleaning and Insulator washing, oil sampling, thermographic surveys, relay calibrations, and breaker testing. Each program is supported by defined procedures, inspection intervals, and documentation consistent with DSC and manufacturer specifications.

Findings from maintenance activities are used to update asset condition records and inform future investment planning. Assets exhibiting accelerating deterioration or rising maintenance costs are identified as potential candidates for renewal consideration. This integration between maintenance and capital planning ensures that Elexicon's asset management practices remain coordinated, risk-informed, and aligned with long-term system reliability objectives.

Refer to Exhibit 4 - Tab 1 – Schedule 4 for further details on Elexicon's maintenance programs.

1.3.6 Connections Planning

Elexicon's Connections Planning process ensures that new customer connections and load additions are evaluated, designed, and implemented in a safe, reliable, and transparent manner. This process supports customer growth, DER integration, and electrification while maintaining compliance with the DSC and the Electricity Act, 1998.

The process begins with an initial capacity and feasibility review, where Elexicon assesses the available capacity on the distribution system to determine if the requested load or generation can be accommodated. This is followed by a preliminary consultation with the customer to review connection options, timelines, and potential system constraints.

Where required, a Load Impact Assessment (LIA) or Connection Impact Assessment (CIA) is performed to evaluate the technical effects of the proposed connection on the distribution network. These studies assess voltage performance, thermal loading, protection coordination, and power quality to ensure that the new connection does not adversely impact existing customers or system reliability.

Once the assessments are complete and the connection is approved, Elexicon issues a formal Offer to Connect (OTC) in accordance with the DSC. The OTC outlines the technical requirements, timelines, and cost responsibilities under which Elexicon agrees to connect the customer's load or generation project to the distribution system. Capacity is not guaranteed until the OTC is executed by the customer. Upon acceptance, the OTC forms a binding agreement between the customer and Elexicon, after which the project advances through detailed design, construction, and final energization.

To improve transparency and facilitate early-stage planning, Elexicon provides a Distribution System Capacity Map, which identifies available feeder and substation capacity across its service territory. The map is intended for preliminary reference only and does not guarantee capacity availability, as real-time conditions may vary based on pending applications and system constraints.

Through this structured approach, Elexicon's Connections Planning process ensures that customer-driven projects are delivered efficiently, technically sound, and in alignment with system reliability and long-term capacity objectives.

Elexicon also receives DER connection requests and follows a standardized process to facilitate interconnections based on the size and type of the project.

For all micro-generation projects (≤10 kW), Elexicon follows a structured review process, including the submission of Pre-Generation Application form, technical assessment, and execution of Micro Generation Agreements, as outlined in the Distributed Energy Resource Micro Connection Information Package.

For non-micro generation projects (>10 kW), Elexicon follows a structured review process, including the submission of Preliminary Consultation Information Requests (PCIR). Next, a formal Connection Impact Assessment (CIA) is required to assess the technical feasibility, risks, and infrastructure needs of the project. These steps, including design submission, SCADA integration (if applicable), and protection & coordination (if applicable) are detailed in the DER Non-Micro Generator Connection Package.

By embedding these DER connection procedures within planning, Elexicon ensures that both forecasted and real-time connection demands are analyzed using standardized technical and regulatory processes. This enhances the accuracy of capacity expansion planning and supports the integration of low-carbon energy resources within the distribution system.

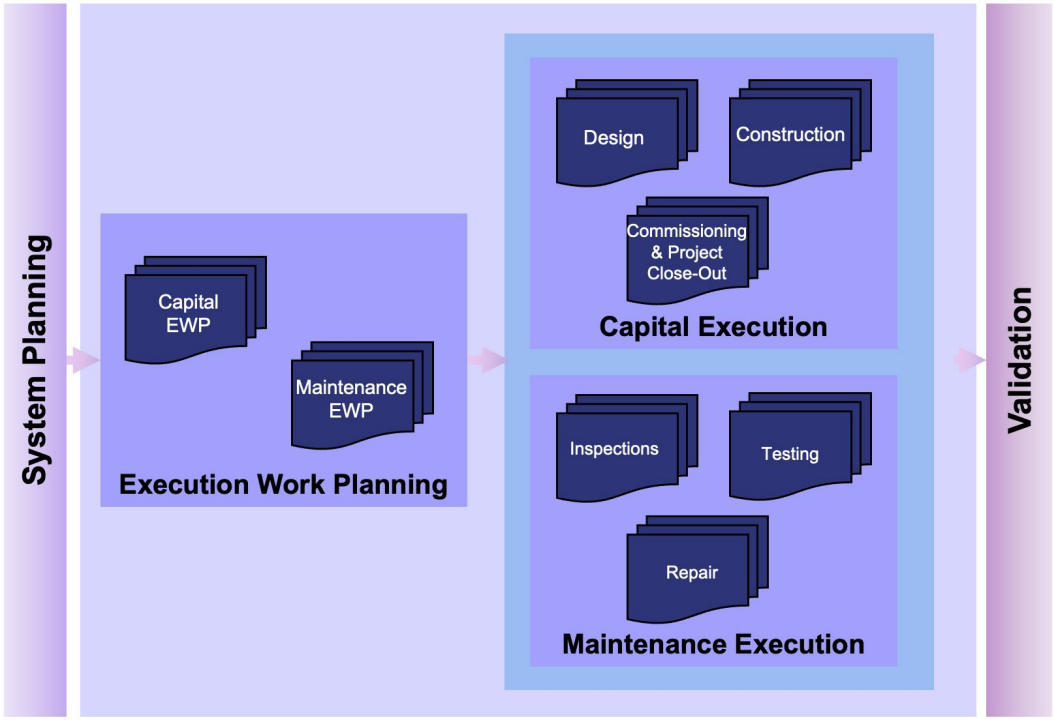
1.4 Execution

The Execution stage represents the implementation phase of Elexicon's AM Process, where capital and maintenance investments identified through System Planning are delivered. This stage focuses on turning strategic investment decisions into tangible system improvements through effective planning, design, construction, inspection, and maintenance execution.

Elexicon's execution framework ensures that all approved projects and programs are delivered safely, efficiently, and in accordance with regulatory, technical, and financial requirements. It integrates cross-departmental coordination between Asset Planning and System Engineering, Program Delivery, Design & Construction, SCC, and Supply Chain to ensure that resources, materials, and schedules are aligned with Elexicon's annual investment targets.

Figure 10 below illustrates Elexicon's Execution Framework, which includes the processes used to translate approved investments into completed capital projects and maintenance activities.

Figure 10: Execution - AM Planning Process



1.4.1 Execution Work Planning

Execution Work Planning (EWP) represents the process through which Elexicon translates approved investment scopes into annual, executable work programs. These programs ensure that planned capital and maintenance activities can be delivered safely, efficiently, and within available resource and budget constraints.

Two coordinated programs are developed as part of this process. The Capital EWP consolidates all approved capital projects, including System Access, System Renewal, System Service, and General Plant investments, into an annual delivery plan. The Maintenance EWP outlines the planned inspection, testing, and repair activities required to sustain asset condition, reliability, and regulatory compliance.

Each EWP is developed collaboratively by Asset Planning and System Engineering, Program Delivery, Design & Construction, and System Control Centre teams to ensure that scope, sequencing, and resourcing align with organizational priorities and delivery capacity. This collaboration ensures that investments are properly staged and coordinated to minimize customer impacts and optimize system outage scheduling.

During EWP development, Elexicon considers several key factors to ensure that the plan is achievable and balanced, including:

- Priority and urgency of the identified needs;
- Customer timing requirements and development schedules;
- Availability of long-lead materials and equipment;
- Annual capital and OM&A budget envelopes;
- Key project requirements such as permits and municipal consent; and
- Balancing of internal and external design & construction resources.

The Capital and Maintenance EWPs are reviewed and approved by Elexicon's management team prior to the plan year. Once finalized, they serve as the operational blueprint for all field execution activities, providing a clear linkage between the planning and delivery functions of the AM Process. This structured approach ensures that each year's investment program is fully executable, resource-balanced, and aligned with Elexicon's safety, reliability, and cost-effectiveness objectives.

1.4.2 Capital Execution

Capital Execution represents the delivery of all approved capital projects identified through the annual Capital EWP. This process transforms the investment plans developed through System Planning into tangible field outcomes.

The Capital Execution process consists of three primary stages:

Design: Detailed designs are developed for each approved project, including drawings, specifications, permits, material lists, and cost estimates. This stage ensures that all projects are technically sound, compliant, and aligned with Elexicon's construction standards. Designs incorporate input from the Asset Planning and System Engineering, System Control Centre, and Supply Chain teams to confirm constructability and coordination with ongoing field activities.

Construction: Following design approval, construction activities are carried out by Elexicon's internal crews or qualified external contractors. Elexicon's qualified external contractors are secured with Master Service Agreements (MSA). This stage also includes the procurement of materials, scheduling of work, and execution of field installations in accordance with Elexicon's safety protocols and quality assurance procedures. Coordination with System Control Centre ensures that outages are safely managed and that customer impacts are minimized.

Commissioning & Project Close-Out: Upon completion of construction, assets undergo testing, inspection, and commissioning, where applicable, to verify that all installations meet design specifications, safety standards, and regulatory requirements. As-built drawings, inspection results, and commissioning records are finalized and submitted for review, and asset information is entered into Elexicon's GIS system to support ongoing asset management and lifecycle planning.

Through this structured and coordinated process, Elexicon ensures that capital projects are delivered on time, within budget, and in compliance with all technical, regulatory, and safety requirements.

1.4.3 Maintenance Execution

Maintenance Execution represents the process through which Elexicon delivers its planned inspection, testing, and repair activities. These activities are derived from the Maintenance EWP and are designed to sustain asset over its typical Useful Life (TUL), ensure regulatory compliance, and maintain overall system reliability.

Maintenance Execution covers in-service distribution and substation assets, focusing on proactively identifying and addressing emerging risks before they result in equipment failure or customer interruptions. Work is prioritized based on asset condition, inspection findings, and operational risk to ensure that resources are directed where they provide the greatest reliability and safety benefit. Maintenance execution work is performed by a combination of Elexicon's internal crews or qualified external contractors.

Key activities within the Maintenance Execution process include:

- **Inspections:** Routine visual inspections of assets to detect deterioration, safety hazards, or non-conformities with construction standards. Inspection frequencies follow the requirements outlined in the DSC and Elexicon's internal maintenance standards.
- **Testing:** Diagnostic and functional testing of assets such as breakers, transformers, relays, and cables to verify performance and identify potential deterioration or end-of-life conditions.
- **Repair:** Execution of corrective actions to address deficiencies identified through inspection and testing activities. This includes equipment repair, component replacement, or temporary mitigations to restore safe and reliable operation.

Maintenance work orders are managed and tracked through Elexicon's WMS, ensuring traceability of inspection results, maintenance completion, and resource utilization. Information collected during these activities, including inspection data, and testing results are validated and incorporated into the asset registry and ACA framework to support ongoing risk evaluation and future capital and maintenance planning.

This process provides a direct feedback loop into Elexicon's planning stages by identifying emerging reliability risks, recurring issues, and opportunities to refine maintenance strategies. Through disciplined maintenance execution, Elexicon ensures that its assets operate safely, efficiently, and in accordance with regulatory requirements, while supporting continuous improvement across the AM Process.

1.5 Validation

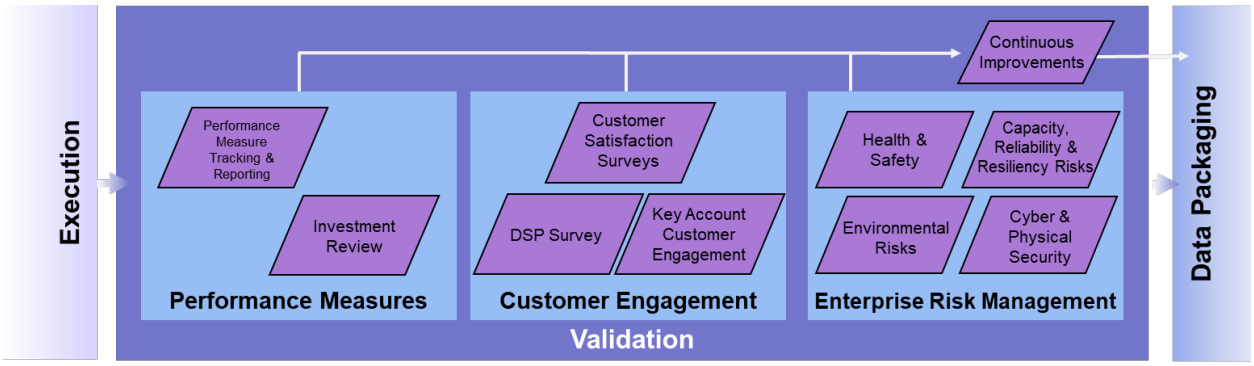
The Validation stage represents the final step of Elexicon's AM Process and serves as the feedback mechanism that drives continuous improvement. It evaluates whether the outcomes achieved through the Execution stage align with Elexicon's performance objectives, customer expectations, and risk tolerances.

Through this stage, Elexicon reviews system performance results, engages with customers to assess service satisfaction and priorities, and evaluates enterprise-level risks to ensure that planning and operational

decisions remain effective and adaptive. Insights generated during Validation are integrated back into the Data Packaging stage to refine asset data, improve analytical models, and enhance future planning cycles.

Figure 11 below illustrates the Validation stage, which encompasses three key functions: Performance Measures, Customer Engagement, and Enterprise Risk Management. Together, these functions enable Elexicon to monitor performance, gather feedback, and continuously improve its Asset Management practices.

Figure 11: Validation - AM Planning Process



1.5.1 Performance Measures

Performance measurement provides the foundation for validating the effectiveness of Elexicon's capital and maintenance investments. It involves tracking system reliability, cost efficiency, and safety outcomes through defined key performance indicators (KPIs) and assessing whether Elexicon's investment programs have achieved their intended objectives.

The Performance Measures function is supported by two primary activities, Performance Measure Tracking and Reporting, and Investment Review. Performance Measure Tracking and Reporting involves the ongoing monitoring of key performance indicators such as SAIDI, SAIFI, project and program delivery metrics (design, construction and maintenance attainment), and budget adherence. These metrics provide quantitative insights into Elexicon's overall system performance and operational efficiency. Investment Review focuses on evaluating individual projects and programs after completion to assess performance against planned budgets, schedules, and scope of work completion. Reviews of the performance

measurement results between planned and actual outcomes to ensure that projects are delivered efficiently, cost-effectively, and in alignment with approved objectives.

Together, these measures provide transparency and accountability, ensuring that Elexicon's investments deliver value to customers and contribute to system reliability, safety, and efficiency.

1.5.2 Customer Engagement

Customer Engagement is a key component of the Validation stage to ensure that the outcomes of the AM Process are aligned with the customer's expectations. This process captures customer feedback on service reliability, cost, communication, and priorities for future system improvements.

Engagement activities include the Annual Customer Satisfaction Surveys and Key Account Customer Engagement sessions. These activities gather feedback from a range of customer groups (residential, commercial, industrial) to understand expectations regarding reliability performance, outage communication, and modernization initiatives.

Feedback collected through these activities is analyzed and integrated into the planning process to ensure that future investments reflect customer preferences, affordability considerations, and service expectations. This continuous dialogue supports transparency and strengthens trust between Elexicon and its customers while ensuring that capital and maintenance plans remain responsive to evolving customer needs.

Additionally, Elexicon conducted a structured customer engagement program to inform the development of this DSP, delivered in two phases. Phase I examined customer needs, preferences, and expectations for the 2027 to 2031 period through online surveys and focus groups. Phase II gathered detailed feedback on the draft investment plan and assessed customer perspectives on the proposed direction, scope, and outcomes of the planned investments. The insights from both phases were incorporated into this filing to ensure that the DSP reflects customer priorities and supports transparent, evidence-based planning. Refer to Exhibit 1 - Tab 7 - Schedule 1 for more details on Elexicon's Customer Engagement program.

1.5.3 Enterprise Risk Management

Elexicon's Enterprise Risk Management (ERM) framework ensures that risk identification, monitoring, and mitigation are embedded across all facets of Elexicon's AM process. ERM evaluates how internal and external risks such as safety hazards, environmental conditions, and cyber or physical security threats may impact Elexicon's ability to meet its performance objectives.

Key areas of focus include Health and Safety, Environmental Risks, Capacity, Reliability, Resiliency, and Cyber and Physical Security risks. These risk categories are continuously assessed through both qualitative and quantitative methods to ensure that risk controls remain effective and aligned with corporate tolerance levels.

Results from ERM activities are integrated into planning and execution to ensure that risk mitigation strategies are proactive and that resources are allocated efficiently. This ongoing assessment process supports compliance with Elexicon's internal governance framework and ensures that decision-making across the organization remains risk-aware, resilient, and adaptive to changing conditions.

1.5.4 Continuous Improvement

Continuous Improvement represents the mechanism through which insights from the Validation stage are integrated back into Elexicon's AM Planning Process to strengthen future decision-making and execution. Findings from performance measurement, customer engagement, and enterprise risk management activities are reviewed to identify process enhancements, data improvements, and opportunities to refine analytical methodologies and planning assumptions. These lessons inform updates to investment prioritization criteria, standards, and maintenance practices, ensuring that Elexicon's AM Process remains adaptive and data-driven.

A key component of continuous improvement is the ongoing training and knowledge development of Elexicon's staff. Training programs are designed to maintain alignment with regulatory requirements, technical standards, and safety protocols, while promoting consistency in how planning and field activities are carried out. These programs combine internal knowledge-sharing sessions, external workshops, and cross-functional training initiatives to strengthen coordination between Planning, Engineering, Operations, and Field Services.

The continuous improvement cycle is further supported by the activities undertaken by Elexicon's Standards team. When field equipment fails or exhibits performance anomalies, the Standards team performs a detailed technical review on the affected equipment to determine the underlying causes. Furthermore, where required the manufacturers and/or third-party are also contacted to perform a root-cause analysis. This review includes examination of inspection records, operating conditions, failure modes, and any contributing environmental or loading factors. Where appropriate, the team engages directly with manufacturers to share findings, validate hypotheses, and assess whether design modifications, enhanced quality controls, or updated maintenance practices are required. Insights from these investigations are used to refine material specifications, construction standards, and approved product lists, ensuring that future equipment selections reflect lessons learned and support improved reliability and asset performance, along with safety improvements for Elexicon staff, contractors, and members of the public.

Another critical element of continuous improvement is Elexicon's DxNEXT initiative, an enterprise-wide modernization program designed to enhance data integrity, standardization, and process efficiency. DxNEXT involves the implementation of a fully integrated Enterprise Resource Planning (ERP) solution that connects key systems such as GIS, Work Management, Finance, and Supply Chain. This integration will improve data accuracy, streamline workflows, and enable more advanced analytics and reporting to support evidence-based decision-making.

Figure 12: DxNext Value Drivers to Asset Management



From an AM Process perspective key areas in which the implementation of DxNEXT will support several key areas of improvement, including:

- Asset Analytics and Lifecycle Management: Leveraging data-driven analytics to assess asset lifespan, utilization, and probability of failure to better inform renewal and maintenance decisions.
- Standardized Master Data Integration: Aligning GIS and enterprise asset data to accurately identify and prioritize maintenance activities for assets at risk of failure.
- Material and Resource Visibility: Providing real-time access to asset documentation, spare parts inventory, and resource availability to improve response times and reduce equipment downtime.
- Enhanced Reporting and Risk Assessment: Developing integrated tools to assess asset criticality, optimize preventive and corrective maintenance strategies, and support reliability-driven decision-making.
- Optimized Work Scheduling: Enabling data-informed scheduling that accounts for asset priorities, geographic proximity, and crew availability to improve productivity and resource efficiency.
- Cost and Performance Tracking: Ensuring visibility of maintenance costs, labour utilization, and work performance to identify efficiencies and support accurate financial reporting.
- Automation Enablement: Establishing the foundation for future automation of preventive maintenance activities and workflow execution.

Collectively, DxNEXT represents a major step toward improving process efficiency, optimizing work program delivery, and embedding data-driven decision-making across Elexicon's AM Process. More information on DxNEXT can be found in Exhibit 4 – Tab 1 – Schedule 6 – Appendix A.

Through this structured approach to continuous improvement, including training, data integration, and digital transformation, Elexicon ensures that organizational learning is embedded within the Asset Management cycle. The result is a process that continually evolves to reflect industry best practices, regulatory requirements, and lessons learned from both operational performance and customer feedback.

2. IMPORTANT CHANGES TO ASSET MANAGEMENT PROCESS SINCE LAST DSP FILING

Elexicon continues to advance and refine its Asset Management Process to strengthen decision-making, improve data integration, and support continuous improvement across each planning cycle. Building on this foundation, Elexicon has introduced targeted enhancements outlined below in recent years to improve data quality, analytical capability, and integration across planning functions. Examples include:

Revamped Planning Team: Elexicon has implemented several key organizational and operational changes to strengthen its planning and delivery capabilities. A major initiative involved the revamping of the Asset Planning and System Engineering function, which now integrates Distribution System Planning, Load Forecasting and Substations Planning, Standards and System Studies under a single coordinated framework.

This integrated structure enables a holistic, system-wide approach to identifying capacity requirements, reliability priorities, and emerging system needs across Elexicon's service territory. The enhanced collaboration and results within these functional areas supports more consistent planning assumptions, stronger alignment between capital and maintenance programs, enablement of customer connections and load growth, and improved execution of long-term investment strategies.

Revamped Design & Construction Team: Design, Connections, and Construction functions were consolidated under a single reporting structure to improve coordination across the project lifecycle. This unified Design and Construction team strengthens end to end line-of-sight from design through execution, enhances responsiveness to project and customer needs, and supports consistent, well-coordinated delivery of the capital program and customer connection activities. This structure also improves overall predictability, reduces handoff inefficiencies and enables more efficient end to end project execution.

GIS and Asset Repository: Elexicon has continued to strengthen the accuracy, completeness, and usability of its asset data through targeted improvements to its GIS and enterprise Asset Repository. These enhancements focus on systematically identifying and filling data gaps to improve confidence in asset demographics, connectivity, and condition information. A key outcome of this work has been the reduction of assets categorized with unknown condition or age, allowing Elexicon to generate more complete ACA and Assets Past TUL results. With improved data quality, Elexicon can more accurately assess asset health,

assign condition scores, and determine an asset's position within its lifecycle. This, in turn, enables more defensible, risk-based investment decisions and better prioritization of renewal programs across the distribution system.

Enterprise Resource Planning (ERP): As mentioned in the Continuous Improvement section, Elexicon is implementing an ERP system, through the DxNEXT initiative. This enterprise-wide platform will integrate key business function including asset management, work management, finance, supply chain, and customer service within a unified environment. The ERP system will support improved data centralization, workflow automation, and process standardization, reducing duplication of effort and enhancing visibility across the asset lifecycle. Once fully implemented, DxNEXT will enable more consistent and traceable asset data, strengthen linkages between financial and operational planning, and improve Elexicon's ability to monitor performance and costs throughout execution.

Maintenance and Inspection: Elexicon has advanced its maintenance and inspection processes through improved data collection methods, standardized forms, and enhanced field reporting protocols. These updates ensure that inspection activities are directly aligned with the requirements of asset condition assessments, enabling more accurate and consistent evaluation of asset health across the distribution system. To further support data-driven maintenance planning, Elexicon will pilot Overstory, an AI-powered vegetation management solution that leverages high-resolution satellite imagery to identify and prioritize feeders with elevated vegetation risk. By integrating Overstory's insights into maintenance planning, Elexicon can proactively target areas of highest reliability impact.

Program Delivery: Elexicon continues to enhance its program management oversight of its capital and maintenance execution work programs and has introduced structured processes that are focused on the development and successful delivery of these execution work programs to achieve targeted outcomes. Capital and maintenance execution work programs (EWPs) are created annually, and updated typically mid-year, within the Program Delivery group and provide a constraint balanced set of work plans. Constraints can include items such as overall budget for the work program, material availability, labour resource availability, approved design readiness, system loading considerations if taking equipment out of service, among others. In order to ensure proper capital and maintenance program delivery, tools such as creation of a balanced scorecard along with detailed reporting that can be on a weekly/biweekly/monthly

frequency depending on report topic, are utilized to ensure proper management oversight and to drive timely completion with rigorous cost oversight.

Load Forecasting: Elexicon has revamped its load forecasting process and team structure to strengthen coordination, data integration, and stakeholder engagement. The updated process incorporates direct collaboration with municipalities, developers, and Hydro One to align distribution planning with regional growth trends and infrastructure developments. By integrating customer growth data, historical consumption patterns, and land-use forecasts, Elexicon can more accurately anticipate emerging capacity constraints and system needs. This enhanced forecasting approach supports proactive, evidence-based investment planning that aligns with customer demand and municipal development priorities.

Grid Modernization: Elexicon continues to implement advanced technologies that provide real-time visibility into asset performance and system conditions. These initiatives include the deployment of underground cable monitoring systems on critical cable segments to detect early signs of insulation degradation and predict potential failure events before they occur. Additionally, Elexicon is expanding the use of Communicating Fault Circuit Indicators (CFCIs) along overhead feeders to enable faster fault detection, improved outage response, and enhanced situational awareness. Collectively, these technologies strengthen Elexicon's grid resiliency and ability to transition toward a more predictive and proactive asset management approach.

Grid Resilience: Elexicon recognizes the need for a more adaptive and resilient distribution system that will have increased capability of self-healing, enhanced remote monitoring and operation capabilities, and proactive fault detection to improve outage restoration duration and fault isolation capabilities. Through the analysis of historical outage data, fault location trends, asset condition assessments, and reviews of distribution system automation, Elexicon maintains a comprehensive, system-wide perspective to identify vulnerable areas that require system hardening and/or grid enhancement investments. In addition, strategic grid enhancement investments are anticipated to enhance fault location capabilities and provide opportunities for real-time network configuration, with the objective of minimizing the impact on customers during outage events.

Aligned with the Ontario Energy Board's Vulnerability Assessment and System Hardening (VASH) initiative, Elexicon is enhancing its vulnerability assessment and benefit-cost analysis methodologies. These tools will serve as key inputs in the planning process to help prioritize climate-related vulnerabilities and guide strategic investments in system hardening to improve resiliency, reliability and customer service.

Risk Management Integration: Elexicon continues to identify, monitor, and manage emerging risks through its Enterprise Risk Management (ERM) framework, which provides a structured and dynamic approach to assessing risks across the organization. The ERM framework is closely aligned with Elexicon's AM Process, ensuring that asset-related, operational, and strategic risks are systematically captured, evaluated, and treated. This integration allows insights from enterprise-level risk assessments such as those related to reliability, sufficiency of distribution capacity, and supply chain challenges to inform investment prioritization, maintenance planning, and long-term capital strategies. By embedding ERM principles within the AM Process, Elexicon ensures that its asset management decisions are risk-informed, transparent, and consistent with corporate objectives for reliability, safety, and financial sustainability.

Non-Wires Solutions (NWS): Elexicon recognizes the growing importance of non-wires solutions and the evolution of technologies within the sector and has worked with an external consultant to develop a structured pre-screening framework. This NWS pre-screening framework will be integrated into the asset management process and support consistent consideration of NWS within future planning cycles in conjunction with the benefit-cost analysis (BCA) framework. See Exhibit 2B - Tab 3 - Schedule 5 for more information on Elexicon's NWS activities.

Elexicon continues to pursue opportunities to enhance and mature its AM Process, ensuring it remains responsive to evolving operational needs, regulatory expectations, and industry best practices. The initiatives described above demonstrate Elexicon's commitment to continuous improvement through better data integration, advanced analytics, and proactive risk management. As Elexicon continues to modernize its tools, systems, and governance frameworks, these enhancements will further strengthen the transparency, defensibility, and effectiveness of investment planning and execution.

OVERVIEW OF ASSETS MANAGED

This section presents a description of Elexicon's service area, a summary of the system configuration, the results of the ACA, and Elexicon's system utilization relative to planning criteria.

1. OVERVIEW OF SERVICE AREA

1.1 Customers Served

Table 1 below depicts the number of customers that Elexicon serves based on the customer rate class. The table illustrates the increasing trend in Elexicon's customer based over the historical period, divided into residential, general service <50 kW, general service ≥50 kW and <5000 kW, and large customers ≥5000 kW. Elexicon experienced a 5.6% increase in its customer base from 2020 to 2024.

Table 1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50 kW	Large Customers ≥5000 kW[1]	Total
2024	165,560	11,979	1,473	5	179,017
2023	163,332	11,952	1,436	5	176,725
2022	160,856	11,888	1,405	4	174,153
2021	158,407	11,689	1,464	4	171,564
2020	156,463	11,585	1,437	4	169,489

1.2 System Demand & Efficiency

Table 2 shows the annual season and average peak demand in kW for Elexicon's distribution system. Elexicon experiences a system peak during the summer months. Typically, the peak demand has remained fairly static over the historical years.

[1] Large customer classification applies to an account whose average monthly maximum demand usage for billing purposes is greater than, or is forecast to be greater than, 5000 kW.

Table 2: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2024	537,894	696,556	555,904
2023	574,176	696,474	574,184
2022	586,033	700,859	580,185
2021	541,382	711,257	564,516
2020	562,955	750,598	562,300

Table 3 indicated the efficiency of the kilowatt-hour purchased by Elexicon and delivered. Historical losses as a percentage of purchased energy has been below 4.2% demonstrating the Elexicon has been minimizing system losses over the historical period.

Table 3: Efficiency of kWh Purchased by Elexicon

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2024	3,626,036,248	3,767,002,629	3.9%
2023	3,558,423,901	3,694,371,141	3.8%
2022	3,578,237,132	3,711,169,315	3.7%
2021	3,515,660,342	3,661,088,195	4.1%
2020	3,475,068,653	3,622,240,952	4.2%

1.3 Summary of System Configuration

1.3.1 Ajax-Pickering

The Ajax-Pickering area is a high-growth urban region that encompasses a significant portion of Elexicon's customer base. Elexicon's head office in Ajax also functions as an operations centre for this area.

Power is supplied to the Town of Ajax and the City of Pickering at 44 kV and 27.6 kV voltage levels from transformer substations (TS) owned by Hydro One, as well as from Elexicon's Seaton Municipal Transformer Substation (MTS). Specifically, eight 44 kV feeders originate from Cherrywood TS, three 44 kV feeders and six 27.6 kV feeders from Whitby TS, two 27.6 kV feeders from Sheppard TS, and one 27.6 kV feeder from Malvern TS. The 44 kV feeders supply 11 municipal substations (MS) in the area, which step down the voltage to 13.8 kV. Figure 1 and Figure 2 illustrate the locations of these substations, while Table 5 and Table 6 outline their respective voltage levels, capacities and lengths of overhead and underground circuits by voltage level. The area features an approximately even split between overhead and

underground systems. Most of the distribution network operates at 13.8 kV (45%) or 27.6 kV (39%), with a smaller portion functioning at 44 kV and 8.32 kV.

Elexicon has planned capital investments that will impact the system configuration in Ajax-Pickering. These include voltage conversion projects to transition the system from 8.32 kV to 27.6 kV, which will facilitate switching operations, support growth with improved capacity, and enhance reliability and safety.

The construction and energization of the Seaton MTS represented a major investment to address load growth in North Pickering. This development also provides load relief to other high-voltage substations and increases capacity to support new developments as they are integrated into the existing distribution system.

Currently, Elexicon's system faces capacity-related risks due to sustained high load growth, primarily driven by major residential developments in Seaton, North Whitby, North Pickering, and Port Whitby. Continued growth within the service territory is expected over the forecast period. The planned investments will help mitigate these risks by either reducing them or maintaining them at current levels.

Additionally, there are several projects in the System Service investment category that are expected to alter the system configuration, including the addition of new feeders. The system configuration may also evolve due to road relocation projects associated with transportation infrastructure development and road modifications.

Table 4: Ajax-Pickering Municipal Transformer Substation Voltage and Capacity

Region	Substation	Voltage (kV)	Summer Capacity (MVA)	Winter Capacity (MVA)
Pickering	Seaton	27.6	153	180

Table 5: Ajax-Pickering Municipal Substations Voltage and Capacity

Region	Substation	Voltage (kV)	Capacity (MVA)[2]
Ajax	Applecroft	13.8	25
	Dowty	13.8	15
	Monarch	13.8	25
	Notion	13.8	15
	Pickering Beach	13.8	30
	Westney Heights	13.8	25
Pickering	Bay Ridges	13.8	15
	Fairport	13.8	20
	Sandy Beach	13.8	27
	Squires Beach	13.8	20
	Town Centre	13.8	22

Table 6: Ajax-Pickering OH and UG Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total
8.32-kV	115	9	124
13.8-kV	249	515	763
27.6-kV	273	388	661
44-kV	128	6	133
Total	764	917	1682

[2] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.

Figure 1: Municipal Substations in the Ajax Area

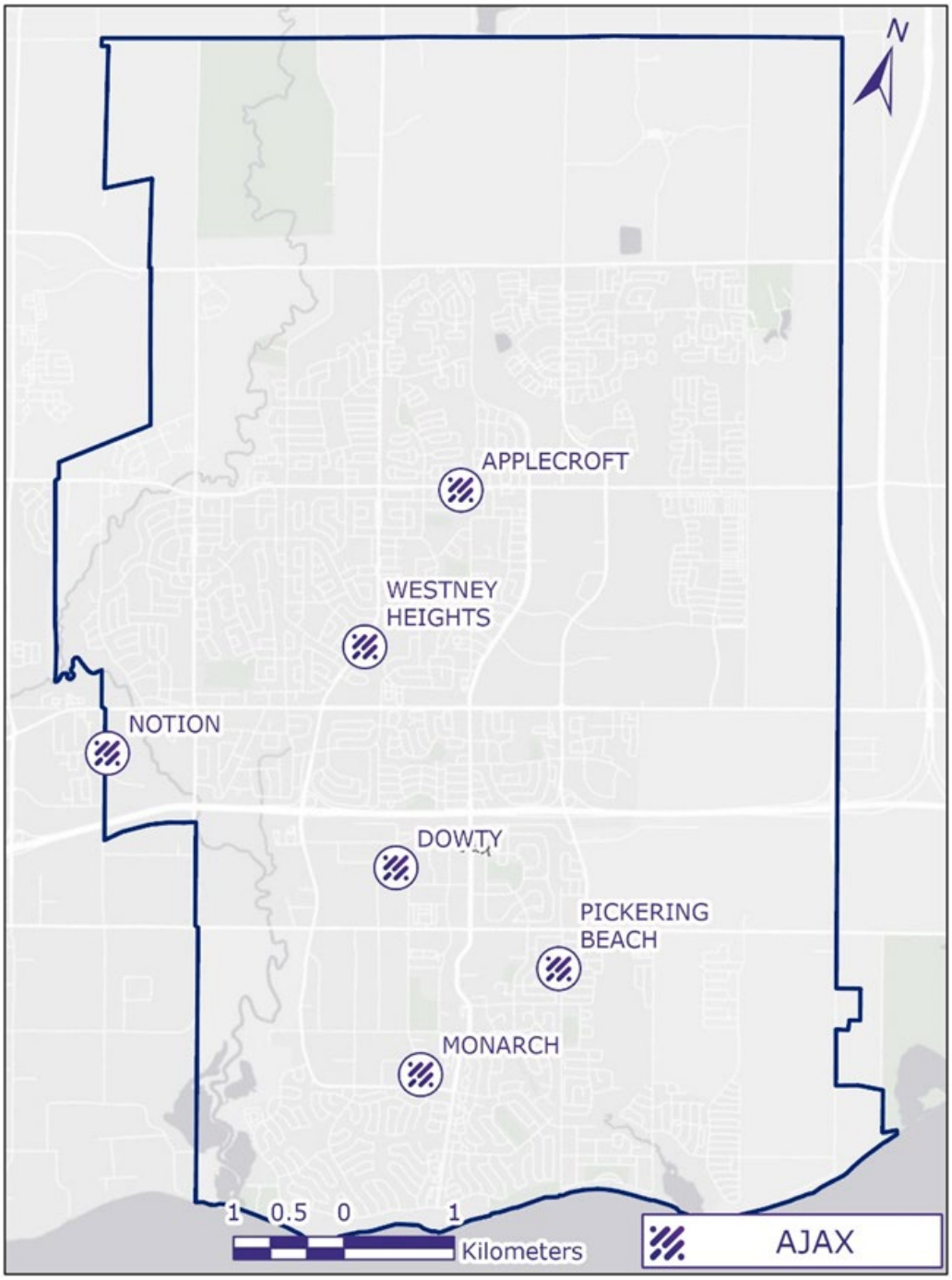
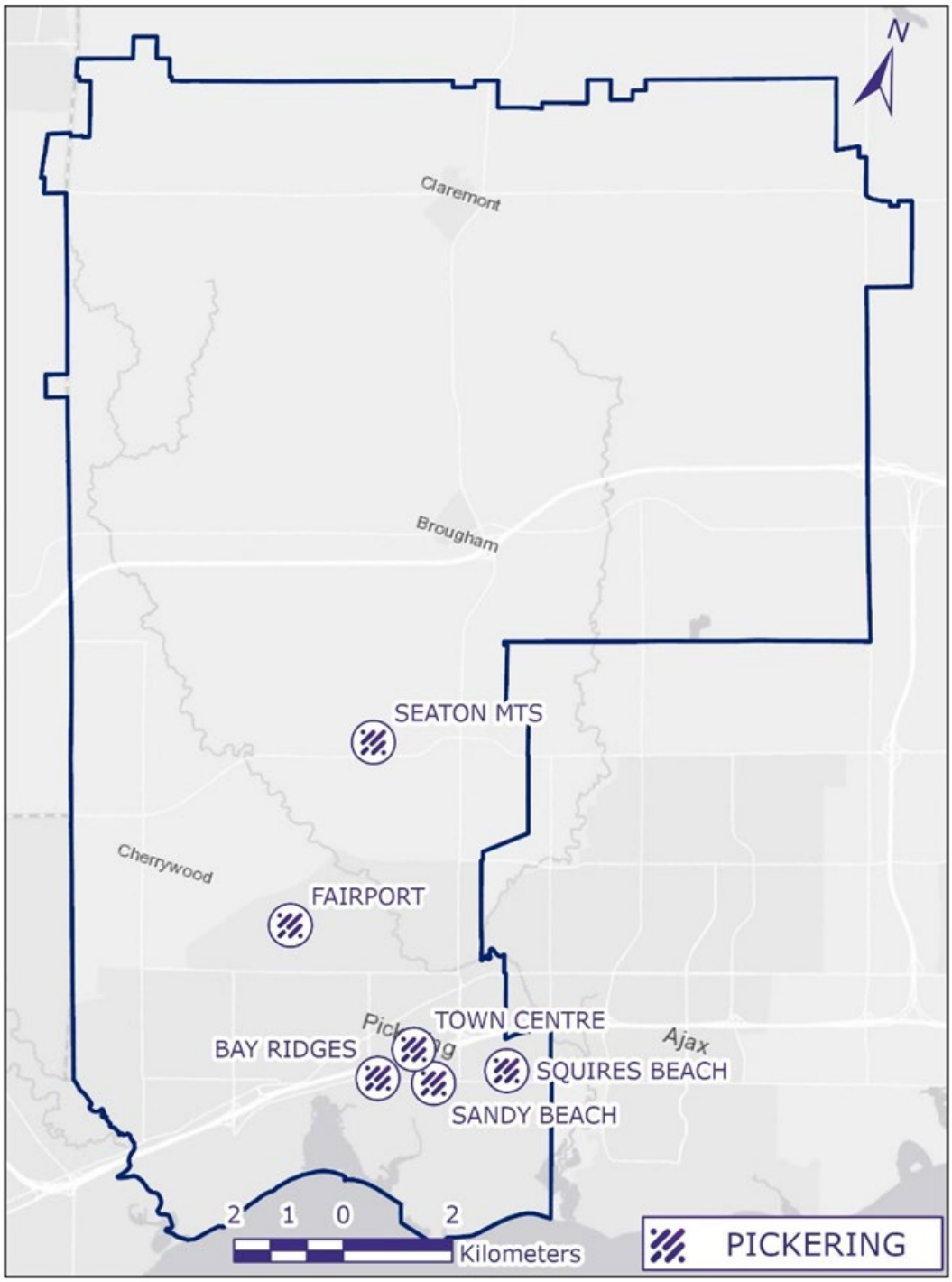


Figure 2: Municipal & Municipal Transformer Substations in the Pickering Area



1.3.2 Whitby Area

The Whitby area is comparable to the Ajax-Pickering area as it has similar weather characteristics, a high growth rate, and a significant portion of Elexicon's customers. While the majority of customers reside in the southern urban core, there is a significant portion of non-urban land in the northern half of this area. The Whitby area receives power at 44-kV from nine feeders egressing from Whitby TS and four feeders egressing from Thornton TS. These feeders supply power to 15 municipal substations (MS) in the area Figure 3 depicts the locations of these substations and Table 7 outlines their voltage and capacity. All MS within the Whitby sub region operate at 13.8-kV. Table 8 below outlines the length of overhead and underground circuits in the area by voltage level. Similar to Ajax-Pickering, there is an approximately equal split between the total overhead circuit length and the total underground circuit length. Nearly all of the distribution line in Whitby is at the 13.8-kV level (86%). There are no planned voltage conversion projects within the area over the forecast period, but other capital investments such as the construction of a new transformer substation in the North Pickering / North Whitby area may impact the system configuration in the future.

Table 7: Whitby Municipal Substations Voltage and Capacity

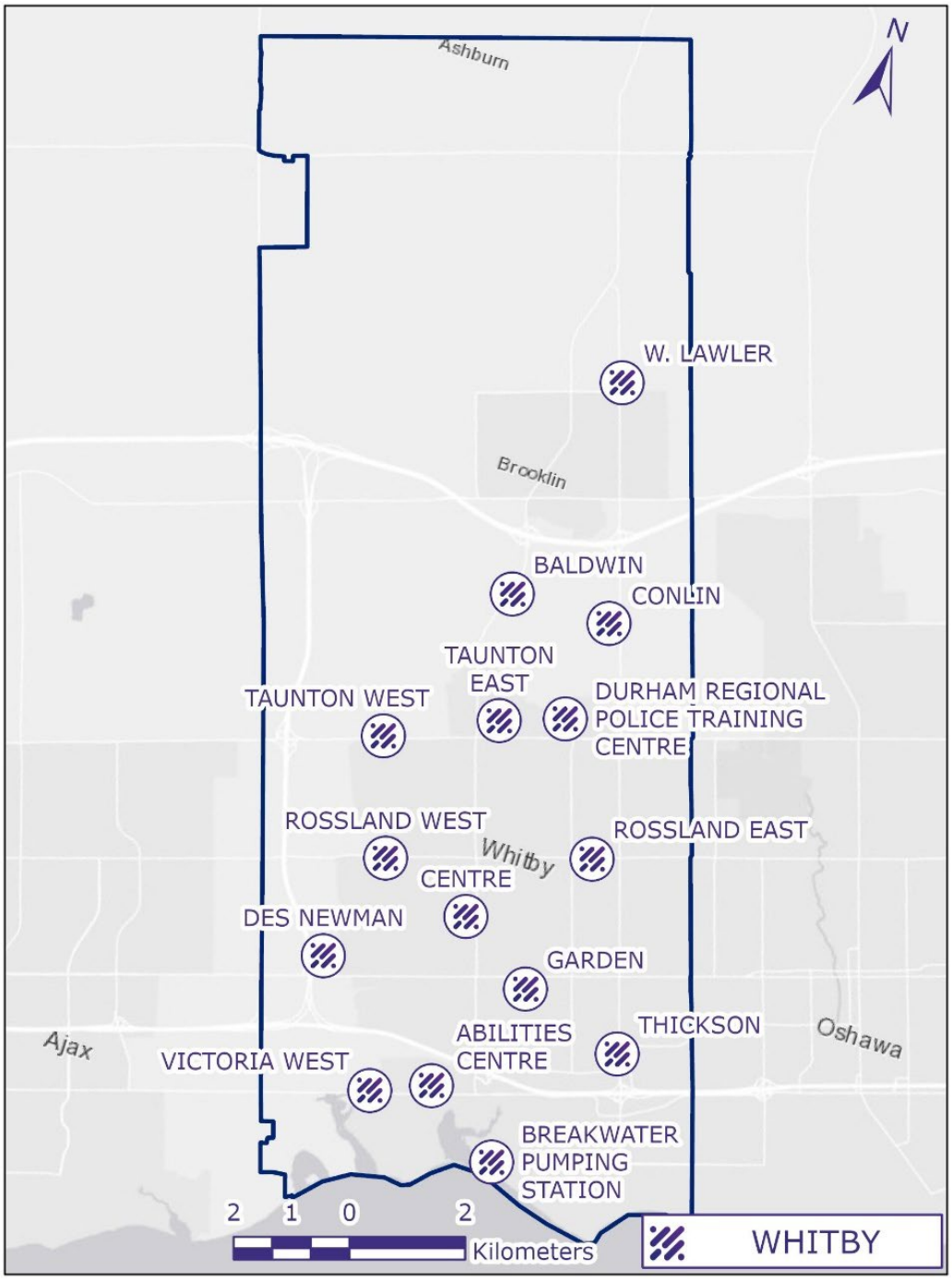
Substation	Voltage (kV)	Capacity (MVA)[3]
Taunton West	13.8	18
Rossland East	13.8	24
Thickson	13.8	24
Rossland West	13.8	20
Baldwin	13.8	20
Garden	13.8	32
Lawler	13.8	35
Victoria West	13.8	12
Centre	13.8	12
Conlin	13.8	18
Taunton East	13.8	18
Des Newman	13.8	24
Durham Regional Police Training Centre[4]	0.6	1
Abilities Centre[4]	0.6	1.5
Breakwater Pumping Substation[4]	0.6	2

Table 8: Whitby Overhead and Underground Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total
13.8-kV	359	636	995
27.6-kV	2	2	4
44-kV	155	5	160
Total	516	643	1159

[3] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.
[4] Dedicated customer-specific municipal station owned and maintained by Elexicon

Figure 3: Municipal Substations in the Whitby Area



1.3.3 Belleville Area

The majority of the City of Belleville area is comprised of non-urban land, and Elexicon's service territory is concentrated in the downtown core and surrounding areas. Belleville shares regional characteristics with Ajax, Pickering and Whitby, including a similar weather profile and customer base. Due to its distance from the Head Office and Operations Centre in Ajax, Elexicon operates a satellite operations centre in the area.

Electricity is supplied to Belleville at 44 kV via six feeders originating from the Hydro One-owned Belleville Transformer Substation (TS). These feeders serve 11 municipal substations (MS), as illustrated in Figure 4. Table 9 provides key details about each substation, including voltage levels and capacity.

The municipal substations in Belleville are rated at either 4.16 kV or 13.8 kV, with Edgehill MS being the sole exception, housing one transformer at both voltage levels. Table 10 also outlines the lengths of overhead and underground circuits by voltage. Most of Belleville's circuit length is overhead (75%), with 46% rated at 13.8 kV. A significant portion (32%) operates at 4.16 kV and consists of aging infrastructure.

Elexicon plans to undertake voltage conversion projects aimed at standardizing the system to 13.8 kV to enhance system efficiency, improve operational flexibility, reduce maintenance requirements, and provide greater capacity to accommodate future load growth and electrification initiatives.

Table 9: Belleville Municipal Substations Voltage and Capacity

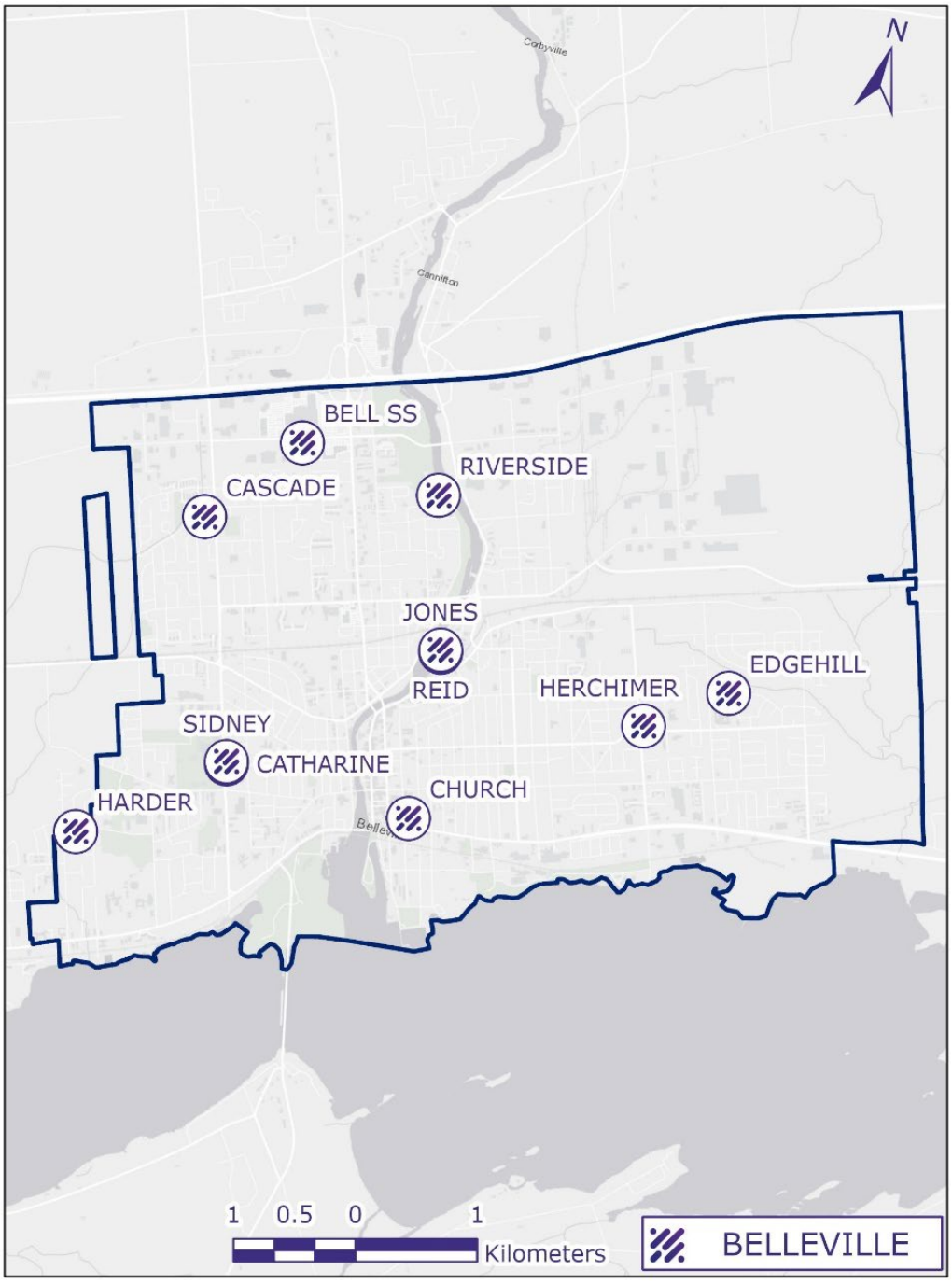
Substation	Voltage (kV)	Capacity (MVA)[5]
Bell	13.8	15
Cascade	4.16	5
Church	4.16	7.5
Catharine	4.16	5
Edgehill	4.16	5
	13.8	15
Harder	13.8	10
Herchimer	4.16	7.5
Jones	4.16	5
Reid	13.8	15
Riverside	4.16	5
Sidney	13.8	15

Table 10: Belleville Overhead and Underground Circuit Length by Voltage Level

Voltage Level	Overhead (km)	Underground (km)	Total
4.16 kV	62	14	76
13.8 kV	90	48	138
44 kV	43	2	45
Total	195	64	259

[5] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.

Figure 4: Municipal Substations in the Belleville Area



1.3.4 Brock Area

The Brock area encompasses the communities of Beaverton, Cannington, Scugog/Port Perry, Sunderland, and Uxbridge. These areas have similar characteristics and relatively stable growth rates. Although they are largely surrounded by non-urban area and natural features, the communities themselves mostly consist of developed land. There is a satellite operations centre in Beaverton which serves these sub-regions. The supply points are outlined below:

- Beaverton is served via one 44-kV feeder egressing from Hydro One owned Beaverton TS.
- Cannington is served via one 44-kV feeder egressing from Hydro One owned Beaverton TS.
- Scugog/Port Perry is served via two 44-kV feeders egressing from Hydro One owned Wilson TS and Enfield TS.
- Sunderland is served via one 44-kV feeder egressing from Hydro One owned Beaverton TS.
- Uxbridge is served via one 44-kV feeder egressing from Hydro One owned Armitage TS.

There are a total of 10 Municipal Substations (MS) in the Brock area which step down voltage to 4.16-kV level – the only exception is Sunderland MS which operates at 8.32-kV. Table 11 outlines key information about voltage and capacity of each substation. Table 12 below outlines the overhead and underground circuit length by voltage level in the Brock area. Much of the circuit line in Brock is overhead (66%), and the majority of the system operates at the 4.16-kV level (88%). There are no planned voltage conversions within the Brock area that would impact the system configuration.

Table 11: Brock Municipal Substations Voltage and Capacity

Municipality	Substation	Voltage (kV)	Capacity (MVA)[6]
Beaverton	Beaverton Main	4.16	5
	Beaverton West	4.16	5
	William Gillespie	4.16	5
Cannington	Laidlaw	4.16	10
Port Perry	Bigelow	4.16	5
	Crandell	4.16	5
	Mabley	4.16	5
Sunderland	Sunderland	8.32	5
Uxbridge	Uxbridge East	4.16	5
	Uxbridge West	4.16	5

Table 12: Brock Overhead and Underground Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total
4.16-kV	64	33	98
8.32-kV	5	4	9
44-kV	4	0	4
Total	73	37	111

[6] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.

Figure 5: Municipal Substations in the Beaverton Area

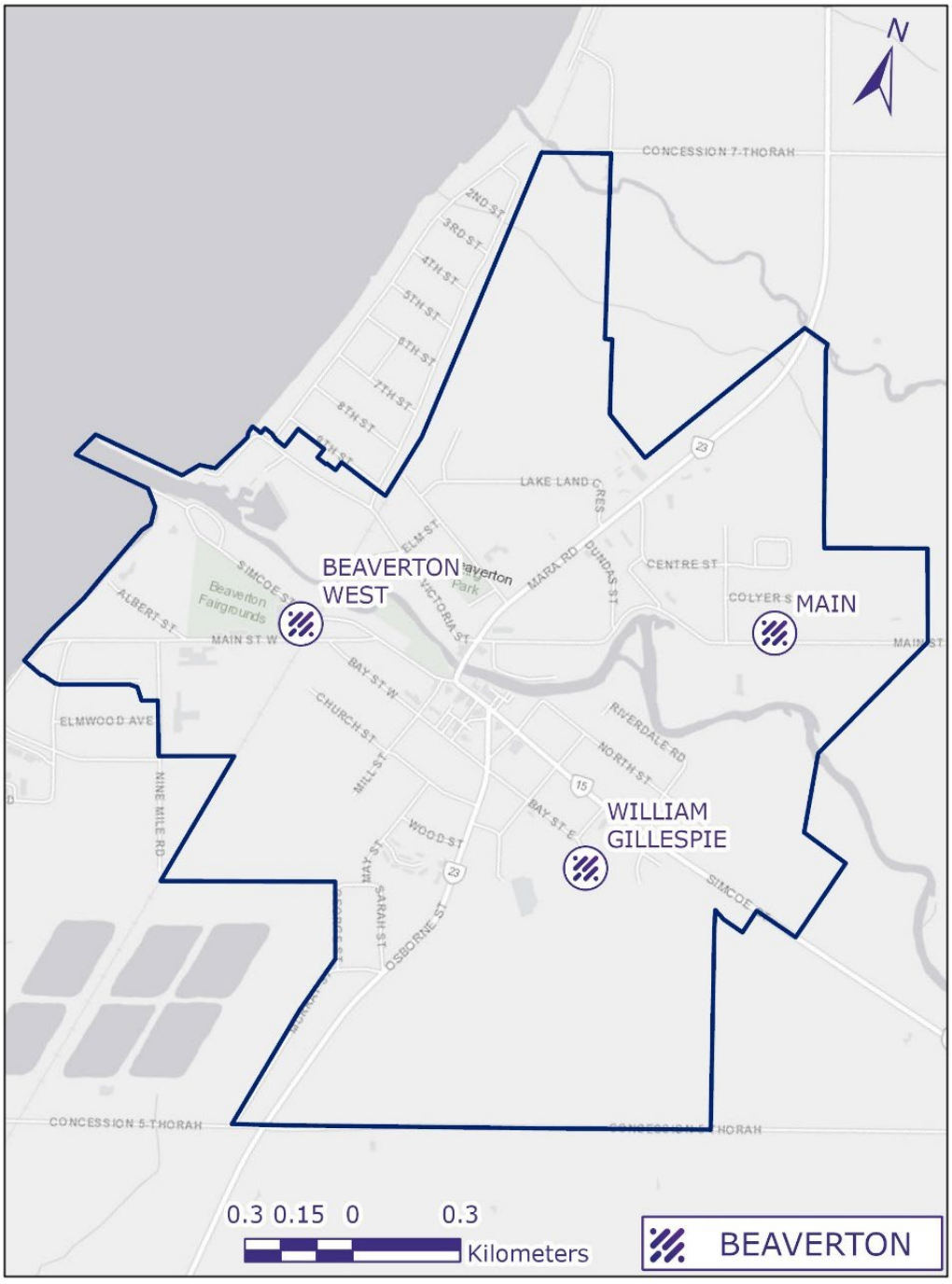


Figure 6: Municipal Substations in the Cannington Area

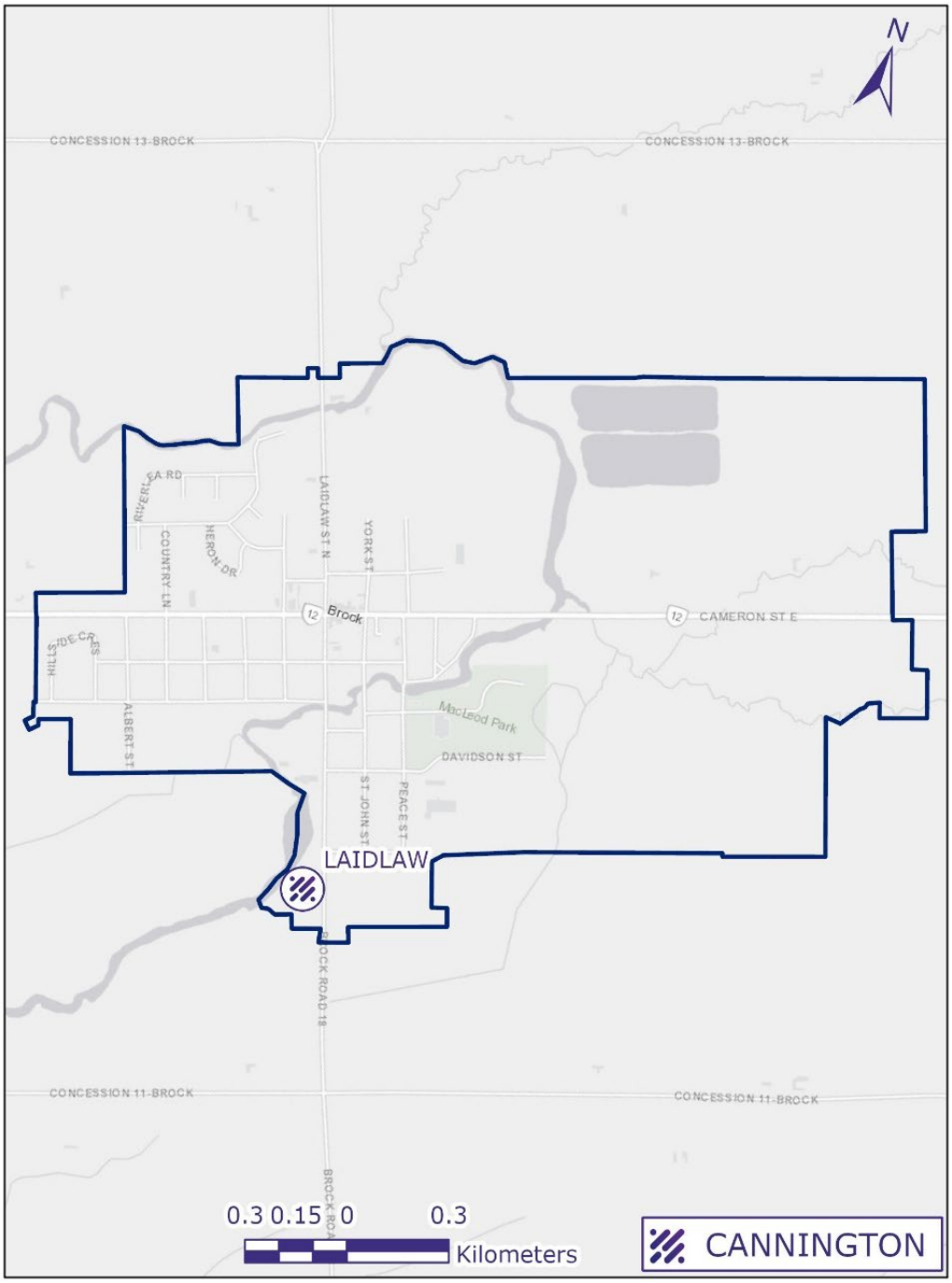


Figure 7: Municipal Substations in the Port Perry Area

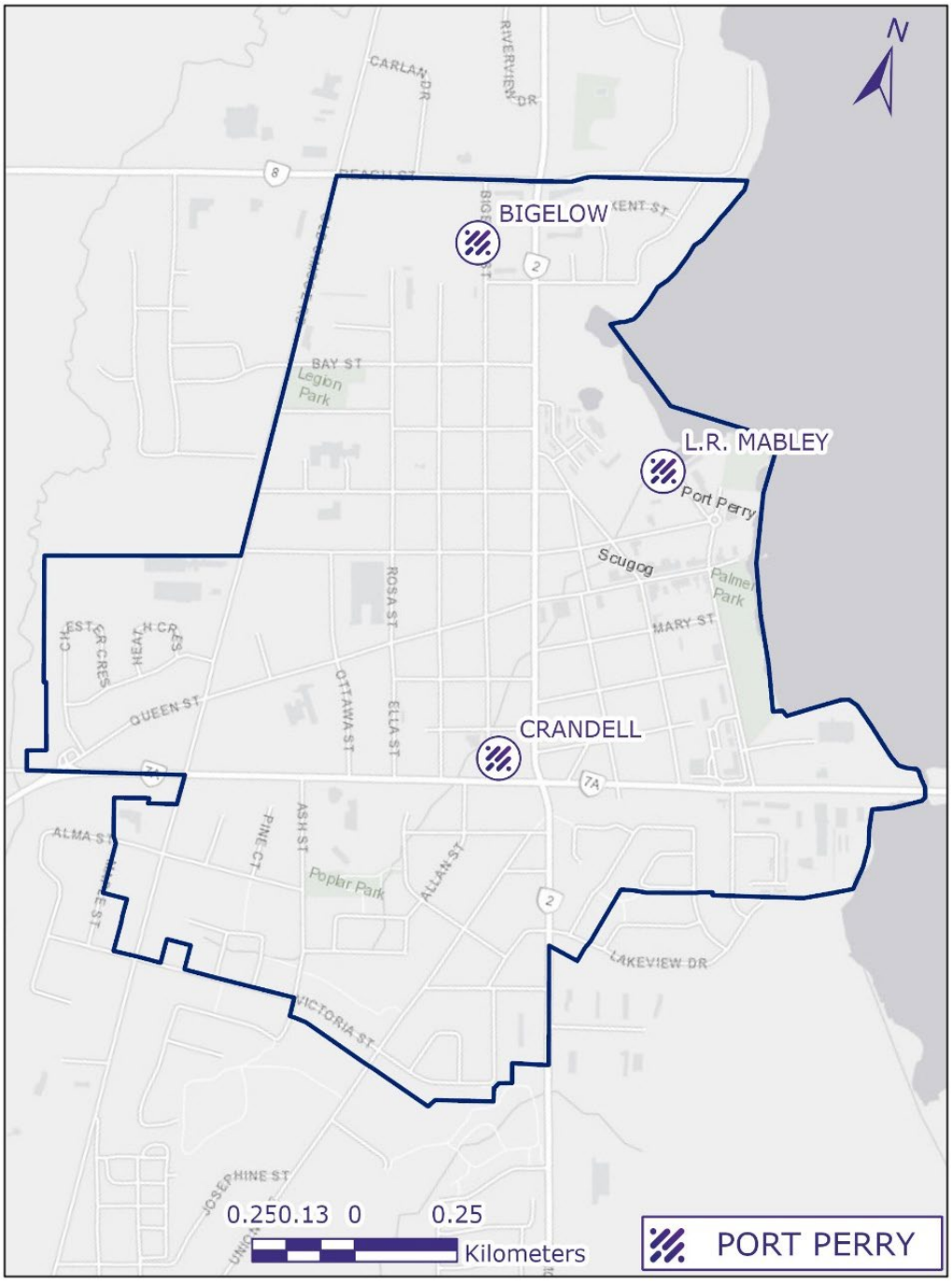


Figure 8: Municipal Substations in the Sunderland Area

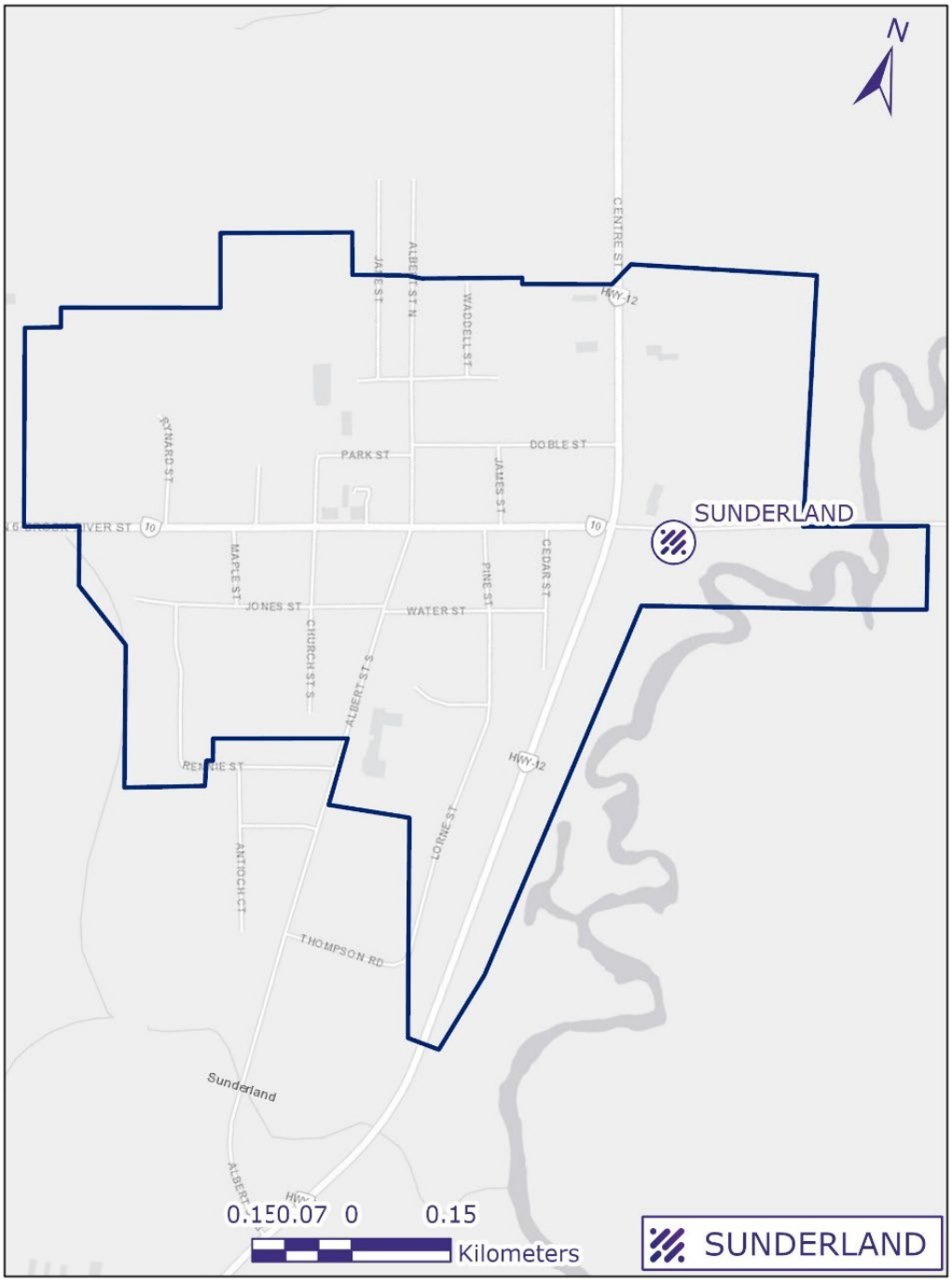
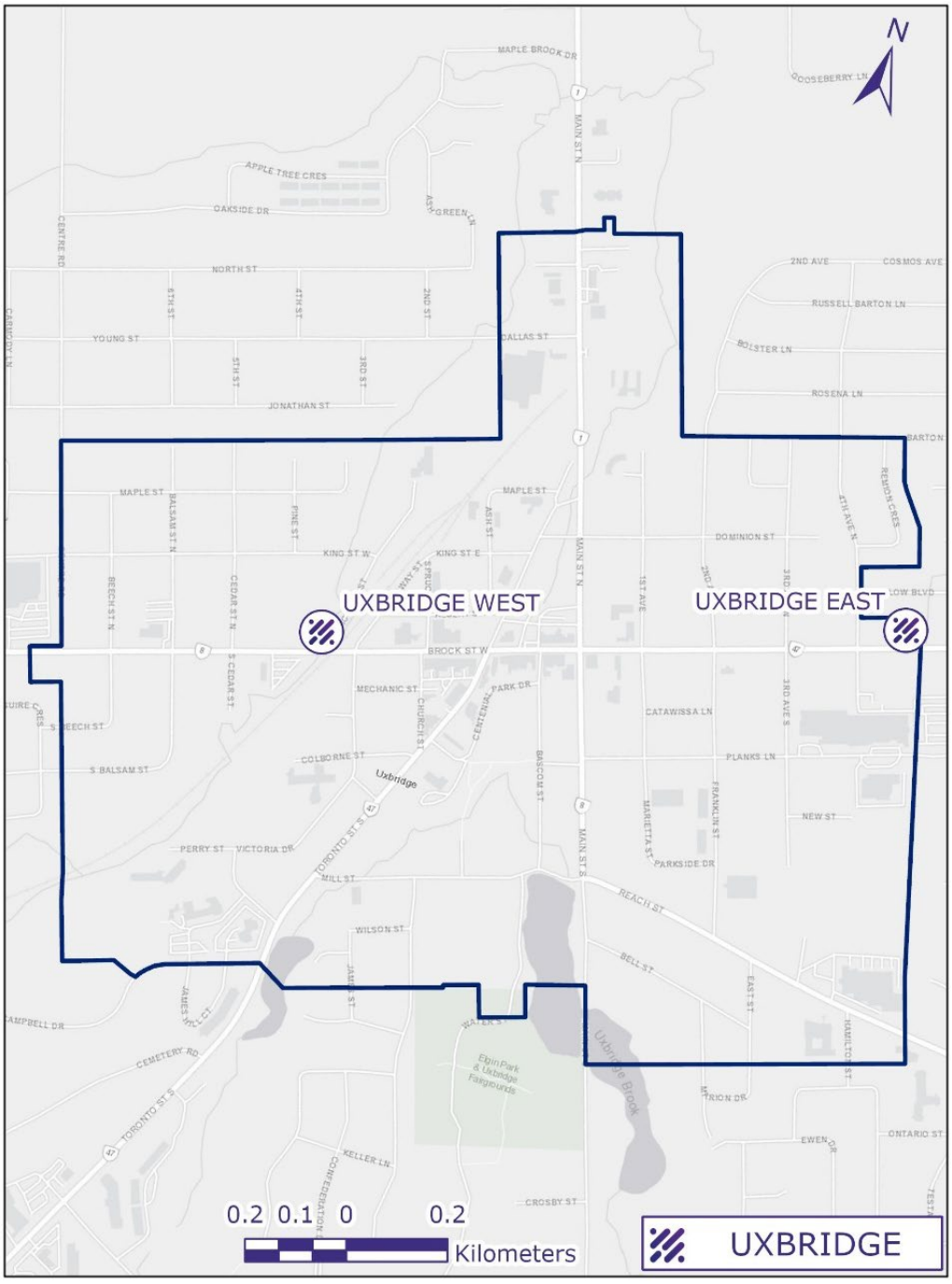


Figure 9: Municipal Substations in the Uxbridge Area



1.3.5 Clarington Area

The Clarington area encompasses the communities of Bowmanville, Newcastle, Orono, and Port Hope. The characteristics of sub-regions within the Clarington area are similar to the municipalities within the Brock area. These communities have stable growth rates and although they are developed, the surrounding area is largely non-urban. There is a satellite operations centre in Clarington which serves this region. The supply points for each municipality are outlined below.

- Bowmanville is served from three 44-kV feeders egressing from Hydro One owned Wilson TS.
- Newcastle is served from one 44-kV feeder egressing from Hydro One owned Enfield TS.
- Orono is served at 8.32-kV from Hydro One owned Orono Distribution Substation ("DS").
- Port Hope is served from two 44-kV feeders egressing from Hydro One owned Port Hope TS.

Elexicon owns a total of 11 municipal substations (MS) within the area – the locations of these substations are depicted in the figures below and Table 13 outlines their voltage and capacity. There is a mix of voltage levels within this area including 4.16-kV, 13.8-kV, and 27.6-kV. Table 14 below outlines the overhead and underground circuit length by voltage level for the Clarington area. There is an approximately even distribution of overhead and underground circuit. Most feeders in the area operate at the 13.8-kV level (41%), but there are material segments at the 4.16-kV (17%) and 27.6-kV (20%) levels as well. Elexicon has planned voltage conversions projects in Port Hope which aim to convert existing 4.16-kV feeders with aged assets to the 27.6-kV level. There are also planned road relocations projects in Bowmanville which may impact the system configuration (Refer to Externally Initiated Plant Relocation in Exhibit 2B - Tab 4 - Schedule 3 - Appendix A).

Table 13: Clarington Municipal Substations Voltage and Capacity

Municipality	Substation	Voltage (kV)	Capacity (MVA)[7]
Bowmanville	Bradshaw	13.8	10
	Liberty North	13.8	15
	Spry	13.8	27
Newcastle	Toronto	13.8	15
	Wilmot	13.8	10
Port Hope	Cavan North	4.16	7.5
	Cavan South	4.16	3
	Howard Walker	4.16	5
	James D. Collins	27.6	10
	Peacock	4.16	5
	Shuter	27.6	10

Table 14: Clarington Overhead and Underground Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total
4.16-kV	33	19	52
8.32-kV	7	0	7
13.8-kV	78	157	234
27.6-kV	37	23	61
44-kV	36	0	37
Total	191	200	391

[7] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.

Figure 10: Municipal Substations in the Bowmanville Area

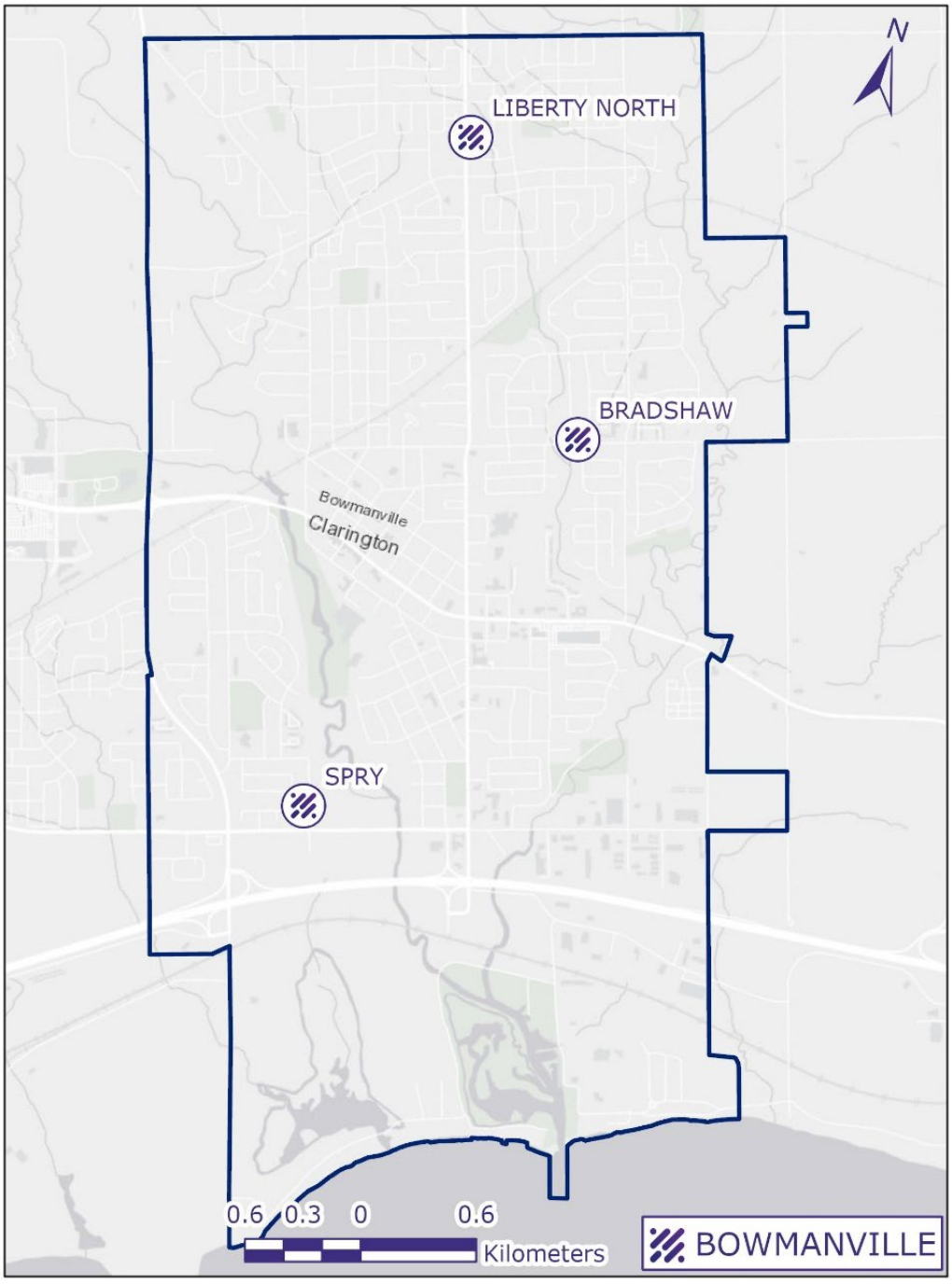


Figure 11: Municipal Substations in the Newcastle Area

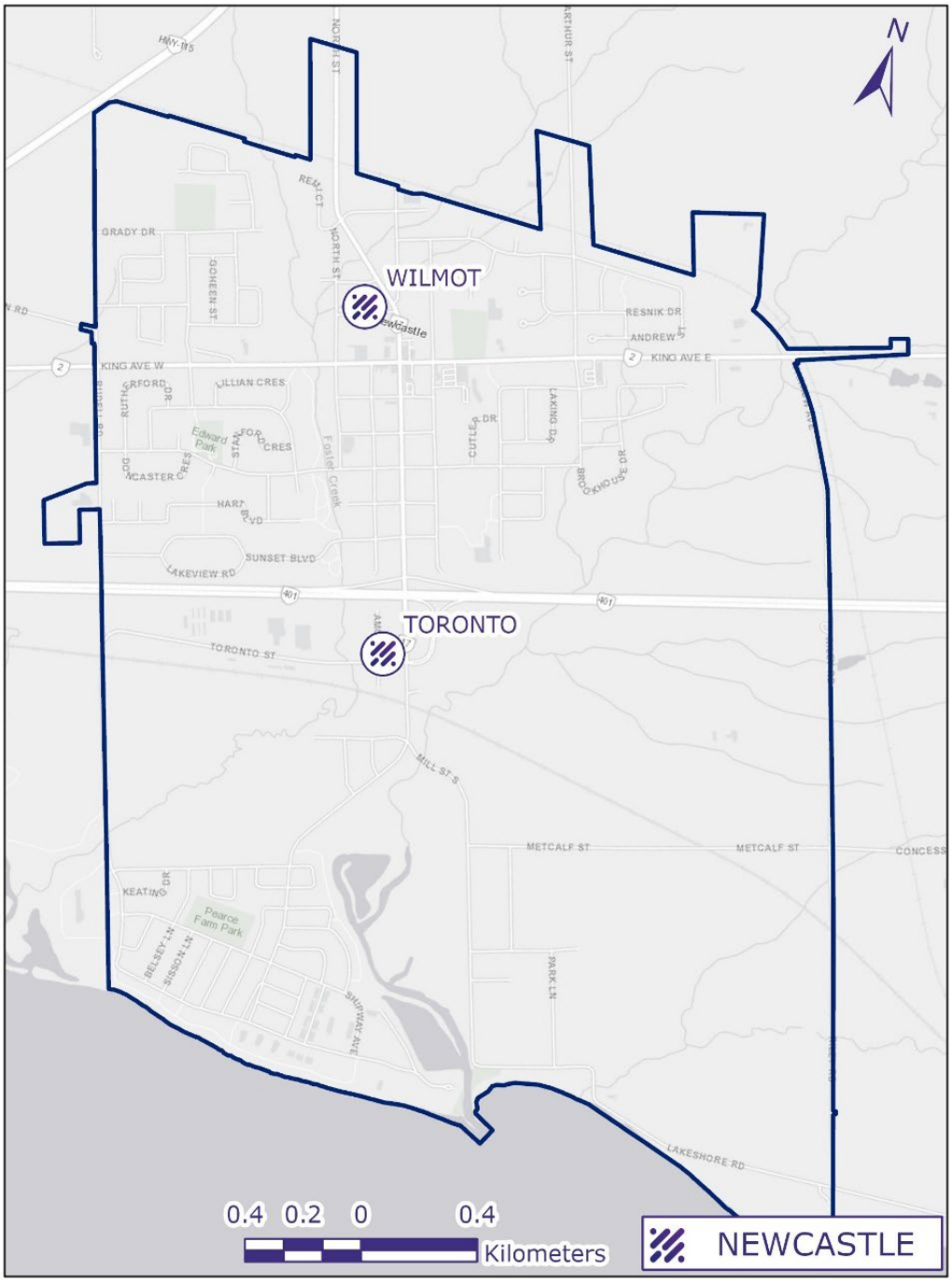


Figure 12: Orono Service Area

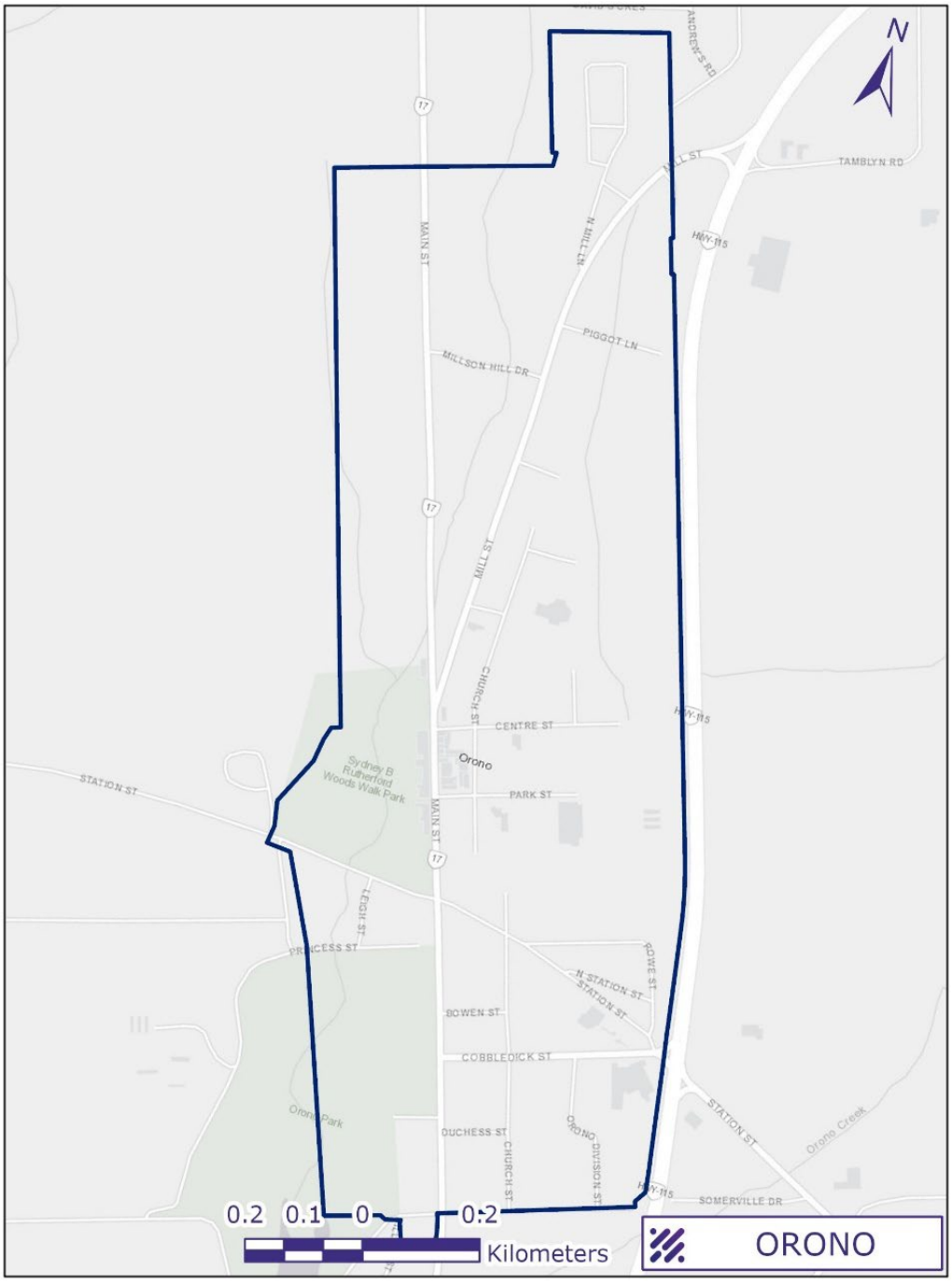
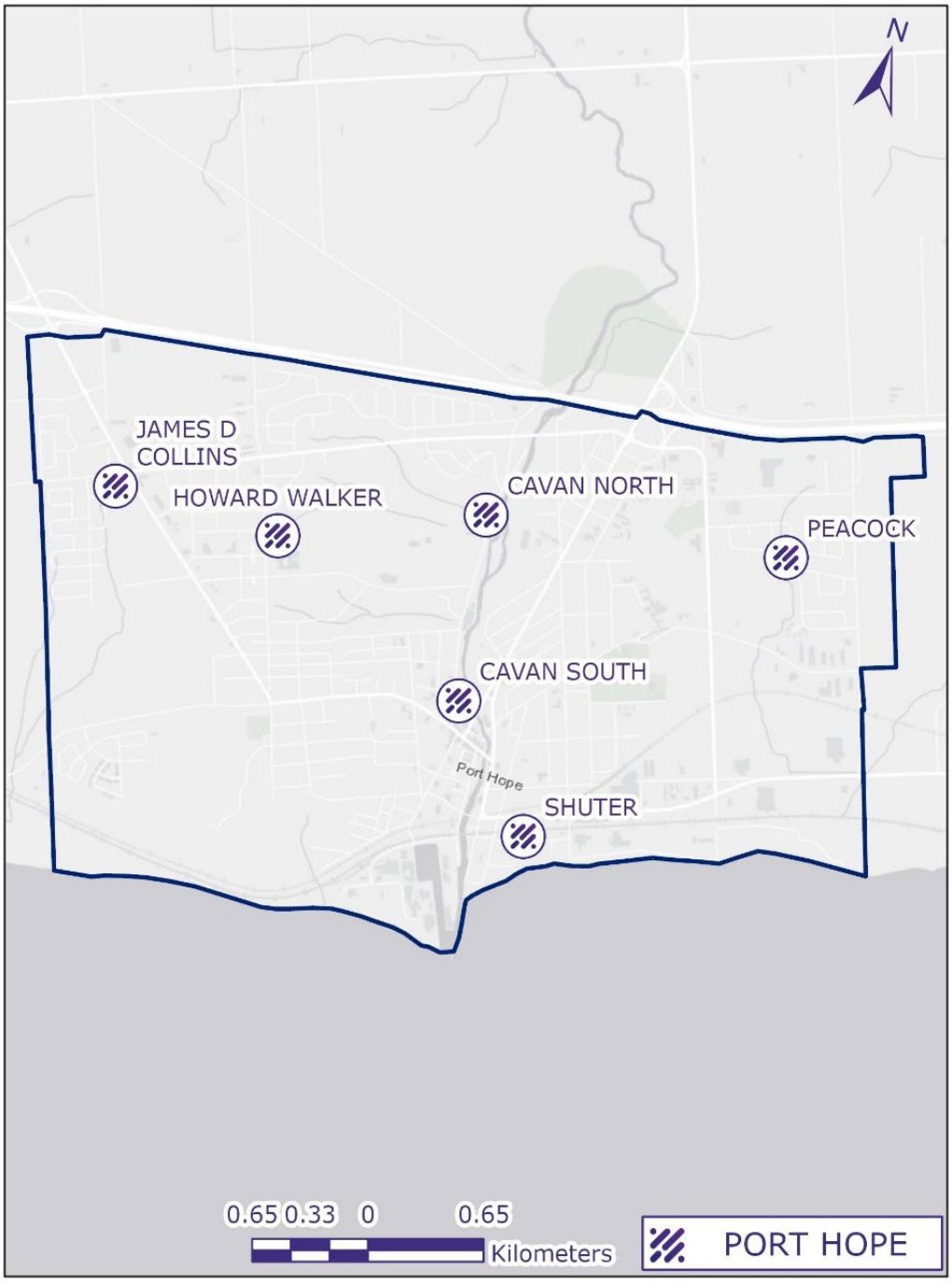


Figure 13: Municipal Substations in the Port Hope Area



1.3.6 Gravenhurst Area

The Gravenhurst area, similar to several other areas within Elexicon's service territory, is experiencing moderate growth. However, a key difference is the overall geographical size of this part of the service territory, the predominance of challenging natural features such as dense forest canopy and water bodies, wildlife and materially different weather characteristics. Another key feature that is unique to this service area is the presence of islands which require electrical service via submarine cables. Elexicon operates a satellite Operations Centre which serves this area. Gravenhurst receives power at 44-kV from Hydro One-owned feeders egressing from Bracebridge TS and Elexicon is embedded to Hydro One-owned Distribution Substations (DS).

Elexicon customers are served directly at 44-kV and at 12.47-kV by feeders egressing from four Hydro One owned distribution substations (DS): Gravenhurst DS, Jones DS, Muskoka Falls DS, and Walkers Point DS. Alternatively, customers are served at either 12.47-kV or 4.16-kV from Elexicon owned municipal substations. The locations of the Elexicon owned MS are presented in Figure 14. Table 15 provides additional information about the Elexicon owned MS in Gravenhurst which operate at either 4.16-kV or 12.47-kV. Table 16 provides an overview of the overhead and underground circuit length by voltage level. Most of the circuit line is overhead (78%) and operates at the 12.47-kV level (86%).

Table 15: Gravenhurst Municipal Substations Voltage and Capacity

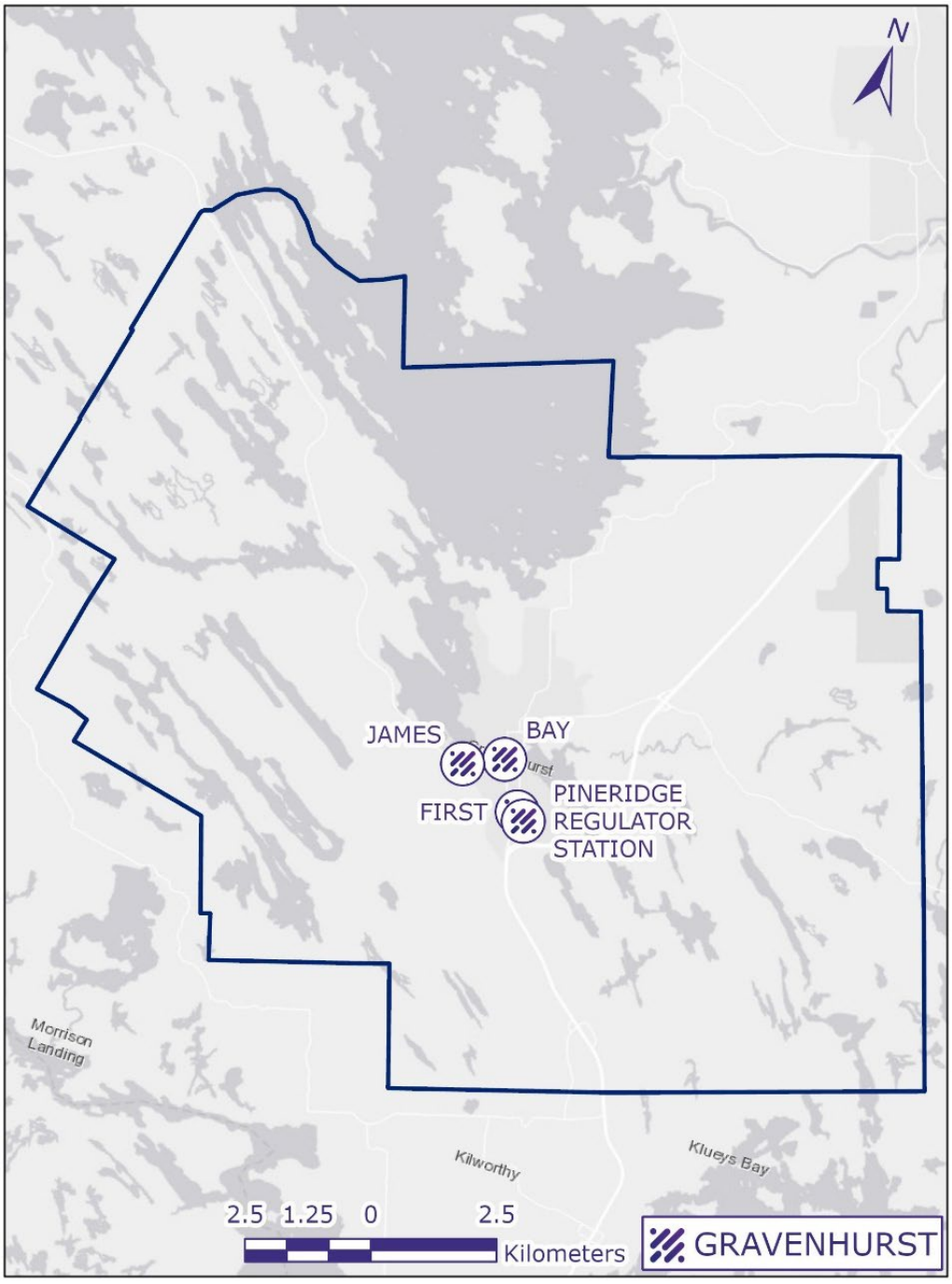
Substation	Voltage (kV)	Capacity (MVA)[8]
Bay	4.16	6
James	12.47	7.5
First	4.16	5
Pineridge Regulator Substation[9]	44	15

Table 16: Gravenhurst Overhead and Underground Circuit Length by Voltage Level

Voltage	Overhead (km)	Underground (km)	Total
4.16-kV	22	12	35
12.47-kV	199	53	252
44-kV	10	0	10
Total	231	66	297

[8] Capacity at ONAN (Oil Natural Air Natural) Transformer rating: Normal operating capacity without additional mechanical fan cooling.
[9] Pineridge Regulator Station is a municipal station used specifically to regulate the 44 kV voltage levels and is owned and maintained by Elexicon.

Figure 14: Substations in the Gravenhurst Area



1.4 Climate

Weather characteristics of three key areas in Elexicon's service territory are provided in Table 17. The areas selected for comparison are Whitby-Pickering-Ajax, Belleville, and Gravenhurst as these areas represent the boundaries of Elexicon's service territory. The weather characteristics summarized below are average values based on five years of historical data from 2020 to 2024[10].

Whitby-Pickering-Ajax historically has had summer highs of 26°C, with a recent extreme peak of 35°C, and winter lows of -9°C. Belleville has historical summer highs of 27°C, and winter lows of -11°C. Gravenhurst historically has had summer highs of 26°C, with a recent extreme peak of 30°C, and winter lows of -15°C.

Table 17: Weather Characteristics for Key Areas in Elexicon's Service Territory

Weather Characteristic		Whitby-Pickering- Ajax Area	Belleville Area	Gravenhurst Area
Temperature (°C)	Summer	19.4	18.2	15.3
	Winter	1.8	1.2	-2.0
Precipitation (mm)	Summer	2.6	2.5	3.01
	Winter	2.2	2.3	2.23
Cooling Degree Days (CDD) (Summer)		2.8	2.3	1.01
Heating Degree Days (HDD) (Winter)		16.3	16.8	20.0

The number of Major Event Days (MED) over the historical period peaked to five in 2020 and four in 2022 while remaining steady between one and two MEDs for the remaining years. However, the MEDs in 2022 caused a significant jump in SAIDI to 20.85, compared to the SAIDI excluding MED of 2.55.

The number of outages caused by adverse weather peaked to 76 in 2022, nearly doubling the previous years count of 39 outages. The adverse weather outages accounted for four percent of outages. Customer interrupted hours caused by adverse weather peaked in 2022 at 19,198 hours. Notably the hours interrupted in 2024 were the next highest at 9,206 indicating that though the number of storms was lower than previous years there was a significant effect on the system. Adverse weather caused three percent of customer interrupted hours on average.

[10] Environment Canada

To help mitigate impacts from adverse weather, and to align with the OEB VASH initiative, Elexicon is exploring opportunities to further integrate storm hardening measures into vulnerable areas of Elexicon's service territory (Refer to Elexicon's Grid Modernization Plan in Exhibit 2B - Tab 3 - Schedule 2 - Appendix A).

1.5 Economic Growth

Elexicon operates in one of Ontario's most dynamic and rapidly expanding regions. The utility's service territory is experiencing sustained growth in population, employment, and infrastructure investment. All of which have a direct impact on electricity demand and system planning.

Durham Region remains a significant area of growth within Elexicon's territory. According to the Region's 2025 Monitoring of Growth Trends Report,[11] the estimated population reached 780,065 residents as of December 2024, up from 732,210 in 2021, representing a 2.2% average annual growth rate. Long-term forecasts project Durham's population to grow to 1.3 million by 2051, with employment nearly doubling from 241,660 jobs in 2021 to 460,000 jobs in 2051.[12] This growth is supported by completed infrastructure such as Highways 401, 407, 412, and 418, and ongoing transit enhancements including GO Transit expansions and rapid bus corridors. These investments are catalyzing residential and commercial development, particularly in Pickering, Ajax, and Whitby, where Elexicon is seeing strong demand for new customer connections and capacity upgrades.

Belleville continues to experience steady and planned growth, with its population projected to rise from nearly 55,000 in 2021 to between 70,000 and 81,000 by 2051.[13] This expansion is being driven by strategic initiatives such as the Loyalist West Secondary Plan, which is designed to accommodate up to 28,000 residents, and the Northeast Industrial Park, which supports industrial development and employment growth. Employment opportunities will be provided through a balance of manufacturing, research and development, education, agriculture, tourism, and commercial and industrial uses in areas designated and determined to be best suited for each economic sector. Due in part to the fact that the City of Belleville

[11] Regional Municipality of Durham, "Monitoring of Growth Trends", (May 23, 2025).
[12] Durham Region, "Envision Durham – Regional Official Plan", (December 13, 2024).
[13] Watson & Associates, "Population, Housing, and Employment Growth Forecast Update – City of Belleville", (n.d.).

includes the largest urban area in the Quinte region, the City of Belleville will continue to be the centre of economic activity and employment opportunities. Across Hastings County, the broader population is expected to grow from 173,200 in 2021 to 223,000 by 2051, with employment increasing by over 17,000 jobs between 2023 and 2051.

Northumberland County, the upper tier municipality for the Municipality of Port Hope, is forecasted to reach 122,000 residents by 2051, compared to 89,365 in 2021.[14] Growth is concentrated in municipalities like Cobourg and Port Hope, which are benefiting from improved transportation links, regional migration, and a shift toward mixed-use development. These trends are contributing to increased electricity demand, particularly in residential subdivisions and commercial corridors.

The Muskoka District anticipates a permanent population increase from 66,674 in 2021 to 99,100 by 2051.[15] Growth in this area is driven by both seasonal and permanent housing development, with rising demand in resort communities and recreational zones. Electrification of heating and transportation is also expected to play a growing role in shaping future load profiles.

In addition to the forecasted growth outlined within the individual district, regional or municipal plans, the province of Ontario has cited there being an urgent housing crisis driven by population growth, affordability challenges, and supply constraints. This has prompted a series of policy responses aimed at accelerating housing development and ensuring municipalities can meet future demand. Specifically, the provincial government has introduced a new Provincial Planning Statement[16] (PPS), effective October 20, 2024, which sets updated 10-year housing targets for 50 of Ontario's largest municipalities. Of these 50 municipalities, Whitby, Ajax, Pickering, Clarington, and Belleville within Elexicon's service area have specific provincial housing targets outlined, with a combined target of 64,100 new homes by 2031 (see Table 18). These targets will have direct implications for electricity distributors like Elexicon, whose infrastructure must evolve to support intensified residential and employment growth.

[14] Northumberland County 2024 Annual Report
[15] District of Muskoka Official Plan 2025
[16] Provincial Planning Statement (PPS), October 2024

Table 18: Housing targets for Municipalities within Elexicon Service Region under the PPS

Municipality	PPS Housing Target (Additional units built by 2031)
Town of Whitby	18,000
Town of Ajax	17,000
City of Pickering	13,000
Municipality of Clarington	13,000
City of Belleville	3,100
Total	64,100

This policy is driving significant residential development within Elexicon's service territory, increasing the need for system expansion projects such as new feeders, transformer substation upgrades, and area reinforcements. The PPS directs municipalities to plan for long-term growth, emphasizing density targets, transit-oriented development, and strategic growth areas.

For municipalities within Elexicon's service territory that were not included in the provincial housing targets under the PPS, housing growth is still forecasted based on regional planning documents. In the Region of Durham, the Township of Scugog, Township of Brock and Township of Uxbridge are forecasted to experience steady growth according to the Envision Durham Plan. The Township of Scugog's households are expected to increase from 8,250 in 2021 to 9,000 by 2031, while the Township of Brock is projected to grow from 4,790 households in 2021 to 5,580 in 2031. The Township of Uxbridge is forecasted to rise from 8,020 households in 2021 to 8,830 by 2031. The Municipality of Port Hope, situated in Northumberland County reported 7,315 households as of mid-2021, with forecasts indicating growth to 9,223 households by mid-2034. In the District of Muskoka, the Town of Gravenhurst anticipates household growth from 5,020 in 2016 to 6,695 by 2036. These projections highlight that even outside of the designated municipalities under the PPS, housing development will continue to drive electricity demand across all of Elexicon's service areas.

2. ASSET INFORMATION

Elexicon Energy's distribution system is a critical infrastructure network comprised of various asset classes that collectively deliver electricity safely, reliably, and efficiently to communities across its service territory.

This asset portfolio is diverse and strategically designed to meet the evolving needs of customers while supporting system resilience and sustainability.

The distribution assets are categorized into several key groups:

Substation Assets: Elexicon's distribution system consists of 62 municipal substations and 1 municipal transformer substation. These facilities step down high-voltage electricity from transmission systems to distribution levels suitable for residential, commercial, and industrial use. Substations are the primary points of electrical supply to customers. Assets comprising this class include power transformers, circuit breakers and reclosers, protective relays, switchgear, substation switches, substation cables, batteries, chargers, buildings and fences, and other ancillary substation equipment.

Overhead Assets: This category includes poles, framing, conductors, crossarms, polemount transformers, overhead switches, and associated hardware. Overhead lines form the backbone of Elexicon's rural and suburban distribution network. These assets are designed for durability and accessibility, enabling efficient maintenance and upgrades. However, overhead assets are particularly susceptible to outages caused by tree contacts, adverse environmental or weather conditions, and foreign interference. Adverse weather factors include rain, ice storms, snow, wind, extreme temperatures, freezing rain, frost, and other severe conditions. Environmental factors refer to abnormal exposure such as salt spray, vehicle exhaust particles, humidity, corrosion, vibration, or fire.

Civil Structures: Supporting both overhead and underground systems, civil structures include foundations, vaults, pads, ducts, and enclosures that house and protect critical electrical components. These structures ensure safety, accessibility, and compliance with regulatory standards.

Underground Assets: These include direct-buried cables, cables in conduit, and submarine cables, as well as padmount transformers, vault transformers, terminations, and switchgear installed at ground level. Underground systems offer enhanced reliability and aesthetics, reducing exposure to weather-related disruptions.

Telecommunications Infrastructure: Elexicon's telecom assets support advanced grid operations, including remote monitoring, automation, and data communication. Fiber optics, wireless systems, and

network nodes enable real-time control and analytics across the distribution system. Communications systems support the control and protection of electrical equipment and are divided between protection and control systems and the SCADA system.

Metering Assets: Elexicon's revenue metering assets include residential and commercial smart meters, repeaters, collectors, the Head End System (HES), and associated data management systems. These assets provide accurate, real-time consumption data for customers and are essential for billing, demand response, and energy efficiency programs. They reliably acquire remote meter readings, facilitating accurate customer billing in compliance with the Ontario Energy Board's Standard Supply Service Code (SSSC) and the requirements of Measurement Canada.

Together, these asset categories form the foundation of Elexicon's distribution network, enabling the utility to deliver power safely and reliably while preparing for future innovations in energy delivery and management.

Several key factors are considered for each major asset type to ensure capital expenditures are implemented effectively and to ensure the continued reliability, safety, and efficiency of Elexicon Energy's distribution system.

Assets Past Typical Useful Life (TUL): When the age of an asset exceeds its TUL, the asset has entered the period in its lifecycle where it is no longer expected to operate reliably. The asset condition may deteriorate rapidly and its likelihood to fail may increase rapidly. When possible, increasing maintenance and inspection attempts to reduce the rate of deterioration and to delay failure in the near term, however assets operating past their TUL will continually elevate the failure risk in the system. Refer to Section 2.1 for further details.

Asset Condition: The condition of an asset will deteriorate due to mechanical wear, electrical stress, environmental exposure and material degradation. The condition of assets are assessed and categorized as being from very poor to very good. Assets in very poor to poor condition have a higher likelihood of failure and to negatively impact reliability, system resiliency, safety and the environment. Assets in very poor to poor condition are prioritized for proactive renewal to manage their failure risk. Refer to Section 2.2 for further details.

Capacity and Utilization: Elexicon Energy's distribution system is experiencing growing pressure from increasing customer load demands, from both new and existing customers, which in several areas now exceed the available system and equipment capacity. These constraints are driven by residential and commercial growth, electrification trends, and evolving energy usage patterns. High utilization rates in specific areas limit Elexicon's ability to accommodate new customer connections, distributed energy resources (DERs), and electrification initiatives (e.g., EV charging infrastructure). Without capacity upgrades, these constraints can delay service requests and hinder regional development. This overutilization can lead to thermal stress, voltage stability, poor reliability, and reduced asset lifespan. Upgrades are required to support load growth and ensure adequate service levels of reliability. Refer to Section 2.3 for further details.

Failure Impact: The degree to which an asset failure may impact customer reliability, system resiliency, safety, the environment and system operations is analyzed. Failure impact is paired with failure likelihood to understand failure risk which is used to validate investment need and determine renewal prioritization. Refer to Section 2.2 for further details.

These factors provide justification for the proposed capital expenditures, which are aimed at renewing aging infrastructure, improving asset health, enhancing system capacity, and reducing operational risk across Elexicon's distribution network.

2.1 Assets Past Typical Useful Life (TUL)

Elexicon's asset base comprises a diverse portfolio of distribution equipment with varying age profiles and condition characteristics. Assessing assets that have exceeded, or are projected to exceed, their Typical Useful Life (TUL) provides critical insight into replacement needs, risk exposure, and long-term investment prioritization.

The figures below provide a visual representation of the age demographics of Elexicon's system-wide distribution and substation assets. The figures summarize the proportion of assets that have not exceeded their TUL, are expected to exceed it in the next five years or have already exceed their TUL.

Figure 15: Current State (2025) Age Demographics of System-Wide Assets

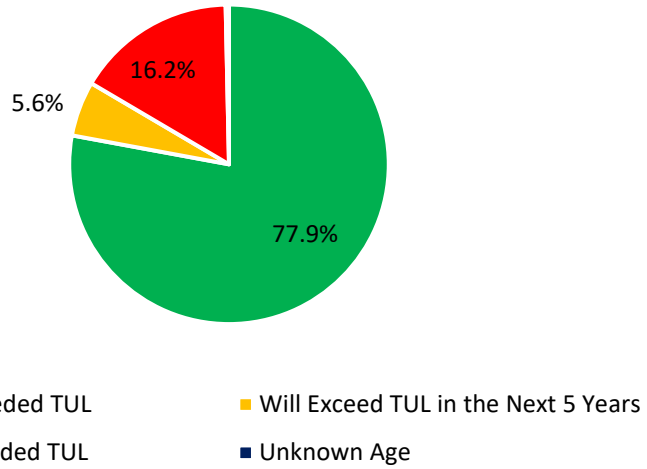


Figure 16: Current State (2025) Age Demographics of Distribution Assets

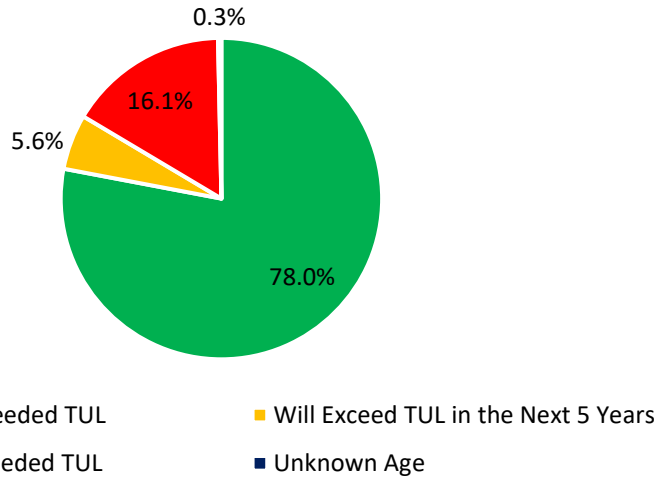


Figure 17: Current State (2025) Age Demographics of Substation Assets

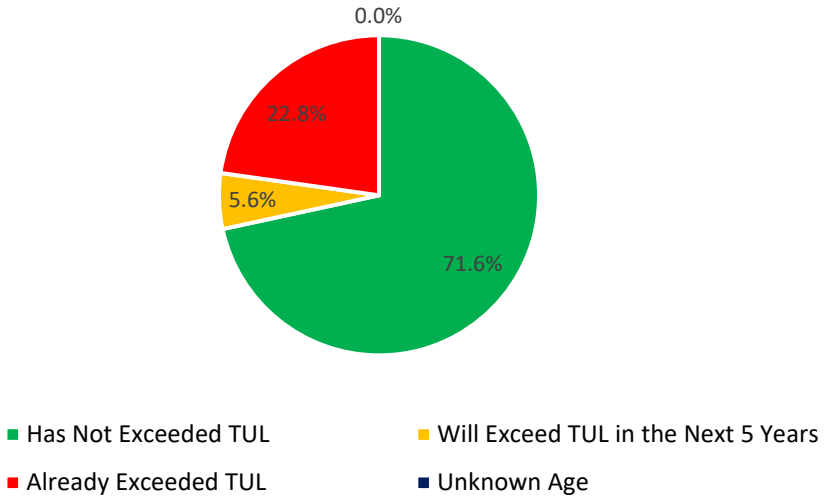


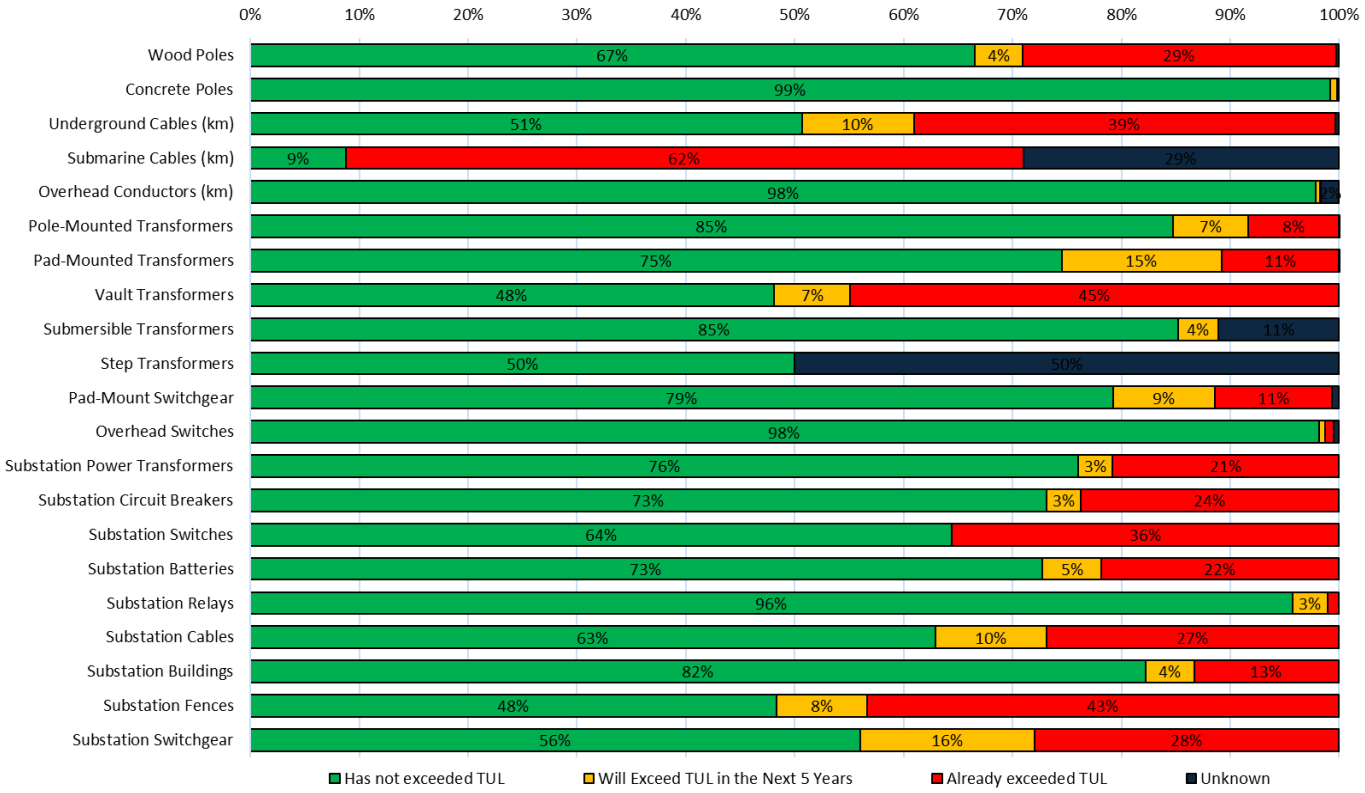
Table 19 below provides the age demographics broken down by specific distribution and substation asset classes. Figure 18 provides a visual representation that complements the quantitative summary by illustrating the relative distribution of assets within and beyond the assets' respective TUL horizons.

Table 19: Age Demographics - Current-State (2025)

Asset Category	Population	Age Demographics (%)			
		Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Wood Poles	34,874	66.5%	4.4%	28.8%	0.3%
Concrete Poles	2,379	99.2%	0.6%	0.2%	0.0%
Underground Cables (km)	2,624	50.7%	10.3%	38.7%	0.3%
Submarine Cables (km)	26	8.8%	0.0%	62.2%	29.0%
Overhead Conductors (km)	4,696	97.8%	0.4%	0.1%	1.7%
Pole-Mounted Transformers	8,831	84.8%	6.9%	8.3%	0.0%
Pad-Mounted Transformers	14,770	74.5%	14.7%	10.7%	0.0%
Vault Transformers	655	48.1%	7.0%	44.9%	0.0%

Asset Category	Population	Age Demographics (%)			
		Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Submersible Transformers	27	85.2%	3.7%	0.0%	11.1%
Step Transformers	6	50.0%	0.0%	0.0%	50.0%
Pad-Mount Switchgear	457	79.2%	9.4%	10.7%	0.7%
Overhead Switches	16,844	98.1%	0.5%	0.8%	0.5%
Substation Power Transformers	96	76.0%	3.1%	20.8%	0.0%
Substation Circuit Breakers	160	73.1%	3.1%	23.8%	0.0%
Substation Switches	149	64.4%	0.0%	35.6%	0.0%
Substation Batteries	55	72.7%	5.5%	21.8%	0.0%
Substation Relays	187	95.7%	3.2%	1.1%	0.0%
Substation Cables	283	62.9%	10.2%	26.9%	0.0%
Substation Buildings	45	82.2%	4.4%	13.3%	0.0%
Substation Fences	60	48.3%	8.3%	43.3%	0.0%
Substation Switchgear	50	56.0%	16.0%	28.0%	0.0%

Figure 18: Distribution of Age Demographics - Current-State (2025) [17]



This aging profile suggests increasing pressure on the system and underscores the requirement for increased capital investment to address risks, maintain reliability, and manage lifecycle costs effectively. A significant portion (21.7%) of Elexicon's asset base has already exceeded its TUL or will exceed its TUL by 2031.

Asset classes with a significantly aging demographic are:

- Wood Poles
- Underground Cables
- Submarine Cables
- Pad-Mount Transformers

[17] Values less than 2% have been removed for clarity.

- Vault Transformers
- Power Transformers
- Circuit Breakers
- Substation Switches
- Substation Batteries
- Substation Cables
- Substation Fences
- Substation Switchgear

2.2 Asset Condition

An Asset Condition Assessment (ACA) is the process of analyzing the condition and performance of an asset and its components using multiple data sources to determine its overall health. ACA leverages asset demographic data, inspection records, and test results. Computational models are applied to this input data to calculate a Health Index (HI), which provides a practical, objective, and standardized measure of asset condition.

Evidence-based HI results enable consistent assessment across asset classes and support the development of informed asset management strategies and policies. Additional information on the ACA methodology is provided in Exhibit 2B – Tab 3 – Schedule 1 and Exhibit 2B – Tab 3 – Schedule 2 – Appendix B.

Elexicon updates its ACA on an annual basis, and each asset class is evaluated using a tailored HI model that applies weighted inputs to quantify condition in a consistent and structured manner. The specific inputs vary by asset class and are informed by available data and industry best practices. Data collection is carried out through existing maintenance activities, including visual inspections, infrared scanning, pole testing, and oil sampling. The resulting ACA outputs support the identification and prioritization of assets with elevated failure risk as part of the utility's needs assessment process.

The figures below provide a visual representation of Elexicon's HI results. The figures summarize the proportion of assets in each condition category for Elexicon's assets system-wide, distribution assets, and substation assets.

Figure 19: Current State (2025) Distribution of Asset Health Index (HI) – System Assets

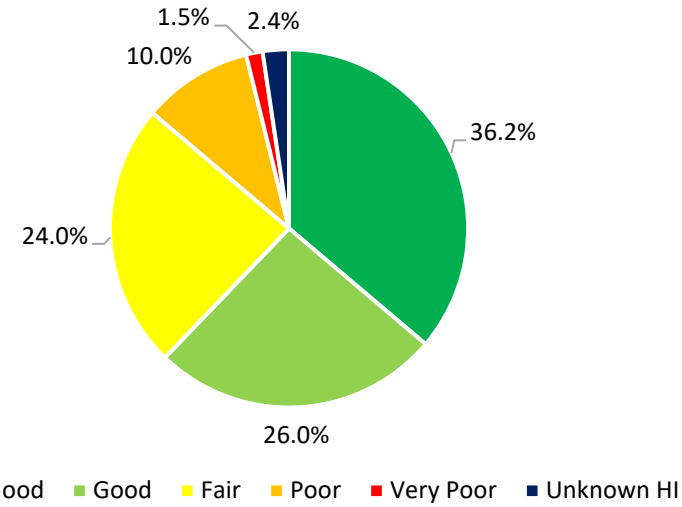


Figure 20: Current State (2025) Distribution of Asset Health Index (HI) – Distribution Assets

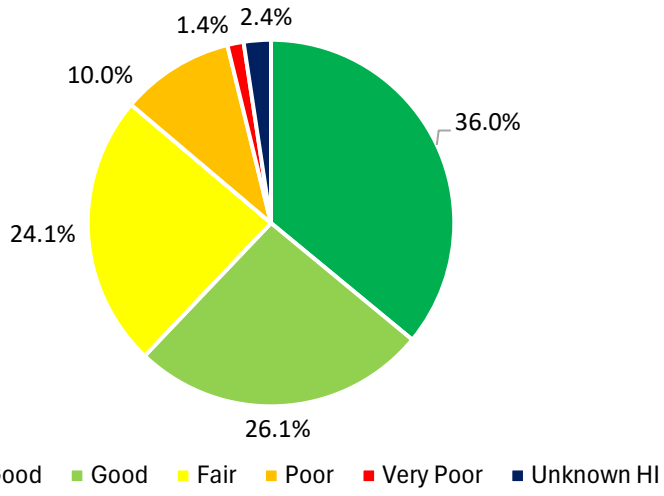


Figure 21: Current State (2025) Distribution of Asset Health Index (HI) – Substation Assets

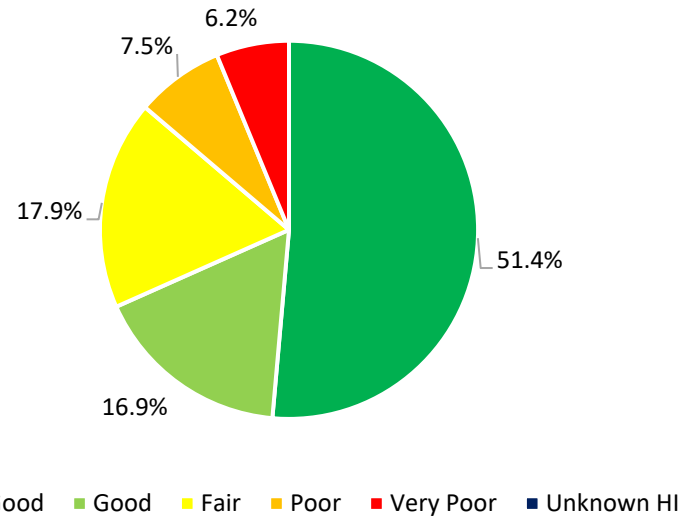


Table 20 below provides the condition demographics broken down by specific distribution and substation asset classes, as well as Data Availability Index (DAI). Figure 22 provides a visual representation that complements the quantitative summary by illustrating relative asset health across the distribution system.

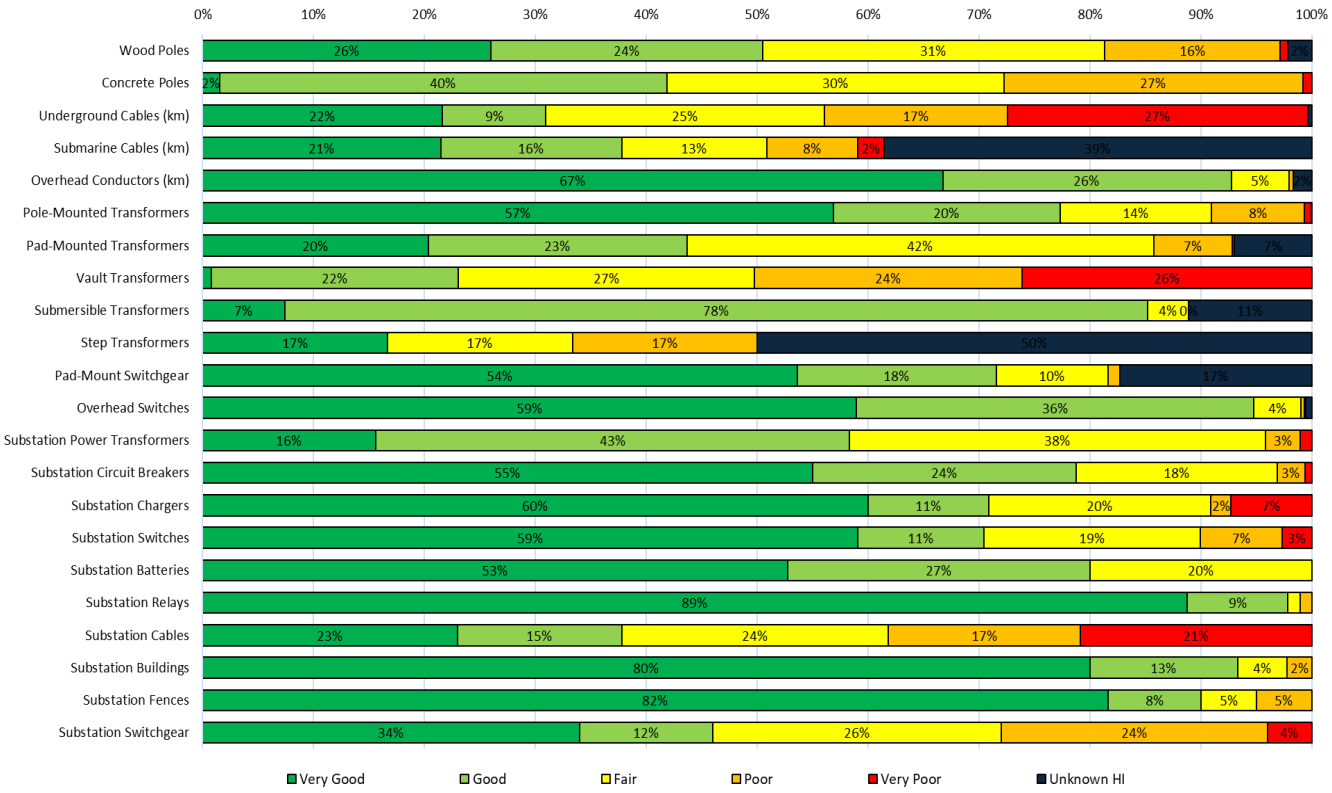
Table 20: Health Index Distribution and Data Availability Index for Distribution and Substation Assets

Asset Class	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	DAI
Wood Poles	34,874	26.0%	24.5%	30.9%	15.8%	0.7%	2.2%	95.8%
Concrete Poles	2,379	1.5%	40.4%	30.4%	26.9%	0.8%	0.0%	100.0%

Asset Class	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	DAI
Underground Cables (km)	2,624	21.6%	9.3%	25.1%	16.5%	27.1%	0.4%	98.4%
Submarine Cables (km)	26	21.5%	16.4%	13.0%	8.2%	2.4%	38.5%	65.1%
Overhead Conductors (km)	4,696	66.7%	26.0%	5.2%	0.4%	0.0%	1.7%	99.1%
Pole-Mounted Transformers	8,831	56.9%	20.4%	13.7%	8.4%	0.6%	0.0%	100.0%
Pad-Mounted Transformers	14,770	20.3%	23.4%	42.1%	7.1%	0.2%	7.0%	96.0%
Vault Transformers	655	0.8%	22.3%	26.7%	24.1%	26.1%	0.0%	100.0%
Submersible Transformers	27	7.4%	77.8%	3.7%	0.0%	0.0%	11.1%	91.0%
Step Transformers	6	16.7%	0.0%	16.7%	16.7%	0.0%	50.0%	50.0%
Pad-Mount Switchgear	457	53.6%	17.9%	10.1%	1.1%	0.0%	17.3%	81.2%
Overhead Switch	16,844	59.0%	35.8%	4.2%	0.3%	0.1%	0.5%	85.5%
Substation Power Transformer	96	15.6%	42.7%	37.5%	3.1%	1.0%	0.0%	96.4%

Asset Class	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	DAI
Substation Circuit Breaker	160	55.0%	23.8%	18.1%	2.5%	0.6%	0.0%	98.9%
Substation Charger	55	60.0%	10.9%	20.0%	1.8%	7.3%	0.0%	100.0%
Substation Switch	149	59.1%	11.4%	19.5%	7.4%	2.7%	0.0%	84.7%
Substation Battery	55	52.7%	27.3%	20.0%	0.0%	0.0%	0.0%	95.8%
Substation Relay	187	88.8%	9.1%	1.1%	1.1%	0.0%	0.0%	91.8%
Substation Cable	283	23.0%	14.8%	24.0%	17.3%	20.8%	0.0%	88.1%
Substation Building	45	80.0%	13.3%	4.4%	2.2%	0.0%	0.0%	99.3%
Substation Fence	60	81.7%	8.3%	5.0%	5.0%	0.0%	0.0%	100.0%
Substation Switchgear	50	34.0%	12.0%	26.0%	24.0%	4.0%	0.0%	98.1%

Figure 22: Percentage Distribution of Asset Health Index by Remaining Useful Life (TUL)[18]



DAI quantifies the completeness of the data used to derive asset condition. The higher the DAI value for the asset class the more robust the condition assessment performed was. DAI for most asset classes are between 80-100%.

Asset classes with a significant demographic in poor or very poor condition are:

- Concrete Poles
- Underground Cables
- Vault Transformers
- Substation Cables

[18] Values less than 2% have been removed for clarity.

- Substation Switchgear

Based on the ACA results, certain asset classes have been identified as requiring focused renewal or replacement over the 2027-2031 DSP period. Distribution assets such as vault transformers and underground cables, along with substation cables and substation switchgear, exhibit higher proportions of Poor or Very Poor condition and therefore represent priority areas for intervention. These observations directly inform the forecasted capital expenditures presented in Exhibit 2B - Tab 4 - Schedule 1, ensuring that investment decisions are aligned with the condition-based risk profile of Elexicon's assets. By targeting these asset classes, Elexicon can optimize reliability, manage risk, and support sustainable long-term system performance.

2.3 Asset Capacity & Utilization

Substation Capacity

Elexicon Energy's capacity planning process analyzes the distribution system in detail to ensure that there is sufficient capacity to supply efficient, reliable, and safe electricity to its customers. Elexicon serves a non-contiguous service area where certain regions may experience demand that exceeds the available capacity, without the ability to simply secure additional capacity from adjacent areas to meet that demand.

Capacity Assessment Overview

The capacity assessment methodology defines how both the current and forecasted system demand is evaluated against available capacity. Using the historical peak load and consolidated System Peak Load Forecast as the primary inputs, current and forecasted peak loads are compared against the available capacity. The available capacity is analyzed at each supply point, to determine the constrained asset and strategically plan capital investments for additional capacity.

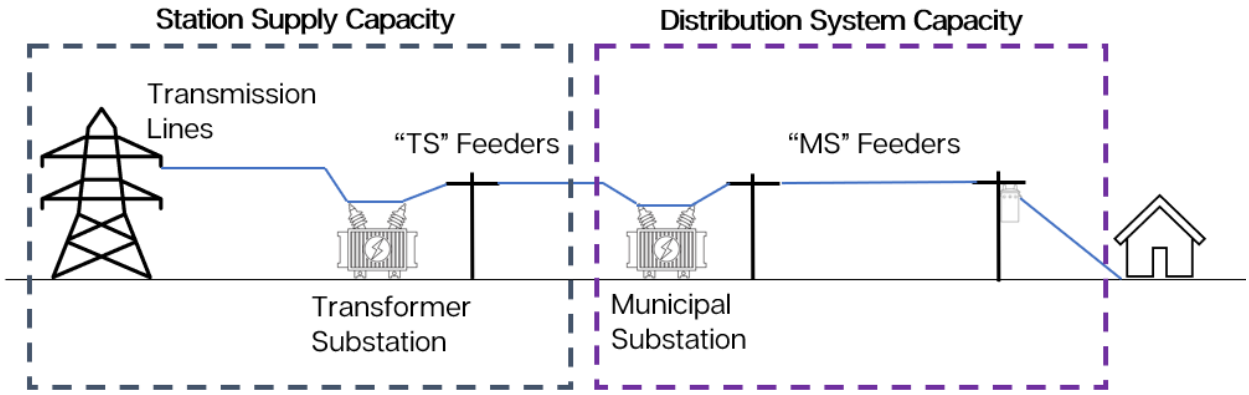
Elexicon's capacity is defined by the two levels illustrated in Figure 23 below:

Substation Supply Capacity: This indicates the limited time rating (LTR) capacity of Transformer Substations (owned by Hydro One), Municipal Transformer Substation ("MTS" owned by Elexicon) or

feeders supplied by Hydro One[19]. Constraints in Substation Supply Capacity indicate a high likelihood that transmission system or TS upgrades will be required to accommodate future demand and maintain system reliability.

Distribution System Capacity: This refers to the planning capacity of municipal substations and their associated distribution feeders. It encompasses all infrastructure within and downstream of the municipal substation, including transformers, breakers, and feeders. The capacity assessment incorporates N-1 contingency planning[20]. Resolving these constraints will require targeted investments to upgrade the specific limiting assets.

Figure 23: Illustration of Substation Supply Capacity vs Distribution System Capacity



Within this section, the overall system capacity will be defined as the minimum of the Substation Supply Capacity and Distribution System Capacity. The specific assets that are analyzed include:

1. **TS Limited Time Rating (LTR):** TS capacity is based on the 10-day Limited Time Rating (LTR), which is a temporary capacity rating that substation transformers can sustain for up to 10

[19] Capacity is calculated based on either the 10-day Limited Time Rating (LTR) or the planning capacity of the feeder, as allocated by Hydro One.
[20] N-1 contingency is a standard planning criterion used in power system engineering to ensure system reliability and resilience. N-1 contingency means that the power system must be able to continue operating without interruption even if one major component (such as a transformer, transmission line, or feeder) fails or is taken out of service unexpectedly.

consecutive days under specific seasonal conditions (either summer or winter), without exceeding thermal limits or compromising equipment integrity.

2. **TS Feeder Capacity**: The TS feeder capacity is based on the planning capacity of the specific feeder utilized. This is based on either the thermal capacity of the feeder assuming N-1 contingency, or the allocated capacity from Hydro One if Elexicon is embedded on the feeder.
3. **MS Planning Capacity**: This is determined as 80% of the maximum ONAF[21] transformer rating of all MS transformers.

Using the capacity and loading details defined above, the following tables within this section will detail the available remaining capacity at the TS and MS levels, for both the current 2025 and 2031 states. This can further be interpreted as follows:

1. **TS Remaining Capacity[22]:** The TS LTR vs. either the historical peak load or the 2031 forecasted system peak load.
2. **MS Remaining Capacity**: the minimum of the TS LTR, TS Feeder Capacity, or MS Capacity vs. either the historical peak load or the 2031 forecasted system peak load.

Table 21 summarizes the overall system capacity and provides an overview of the number of MS categorized with either limited, moderate, or acceptable capacity in both 2025 and 2031. There are 58 MSs included in the overall system capacity assessment, consisting of the 62 total MS within Elexicon's service territory less four (4) substations, which are excluded since they are dedicated customer substations.

[21] ONAF (Oil Natural Air Forced) Transformer rating: Normal operating capacity including additional mechanical fan cooling.
[22] Remaining capacity will be categorized as either limited (0 – 1,000 kVA), moderate (1,001 – 2,000 kVA), or acceptable (2,001+ kVA) as per the OEB Capacity Map requirements.

Table 21: Elexicon Overall System Capacity by Municipal Substation 2025 vs. End of 2031

Capacity	Number of MSs	
	2025 State	End of 2031 State without Investment
Limited Capacity (0 – 1,000 kVA)	44	47
Moderate Capacity (1,001 – 2,000 kVA)	2	2
Acceptable Capacity (2,001+ kVA)	12	9

Of the 58 MSs analyzed, 44 have limited capacity today, with an additional three (3) being added for a total of 47 MSs with limited capacity by the end of 2031 without investment. Most of these substations are distributed across Ajax-Pickering, Whitby, Belleville, and Brock regions, with further details below.

These observations directly inform the forecasted capital expenditures presented in Exhibit 2B - Tab 4 - Schedule 1, with investment decisions made to improve overall system capacity by the end of 2031. The plan is driven by upstream investments at TSs and targeted downstream upgrades, including full MS rebuilds and decommissioning of aging infrastructure. Detailed project-based analysis is highlighted in Exhibit 2B - Tab 4 - Schedule 1.

The following sections will highlight all the TS and MS capacity constraints in detail, and will be broken down by the current state, load forecast growth, and the future state. Regions and specific substations with constraints will be showcased, with the main drivers for growth and potential investments outlined.

Current State Capacity Conditions (2025)

Elexicon's service territory is experiencing significant capacity constraints in the current 2025 state across transformer substations (TS), TS feeders, and municipal substations. Of the six TS or MTS, three have limited LTR capacity, restricting their ability to accommodate additional load. Elexicon is supplied by 58 TS feeders, with 41 operating at limited capacity, three at moderate capacity, and only 14 with available capacity. Similarly, among the 58 municipal substations assessed, 44 have limited capacity, two have moderate capacity, and just 12 have available capacity. The following tables in this section provide a detailed breakdown of the remaining 2025 current state capacity for individual TSs, TS feeders, and MSs.

Table 22: Elexicon Transformer Substation Remaining Capacity 2025

TS	Remaining Capacity (kVA)
27.6 kV	
Seaton MTS	Acceptable Capacity (2,001+ kVA)
WHITBY DESN 1 TS @ 27.6 kV T1/T2	Acceptable Capacity (2,001+ kVA)
44 kV	
Belleville TS	Limited Capacity (0-1,000 kVA)
Cherrywood TS	Limited Capacity (0-1,000 kVA)
WHITBY DESN 2 TS	Limited Capacity (0-1,000 kVA)
WHITBY DESN 1 TS @ 44 kV T1/T2	Acceptable Capacity (2,001+ kVA)

Table 23: Elexicon TS 44kV Feeder Remaining Capacity 2025

TS Feeder	Remaining Capacity (kVA)
Armitage TS	
41M-22	Limited Capacity (0-1,000 kVA)
Beaverton TS	
31M-24	Acceptable Capacity (2,001+ kVA)
31M-29	Acceptable Capacity (2,001+ kVA)
31M-30	Acceptable Capacity (2,001+ kVA)
Belleville TS	
8M-1	Limited Capacity (0-1,000 kVA)
8M-3	Limited Capacity (0-1,000 kVA)
8M-4	Limited Capacity (0-1,000 kVA)
8M-8	Limited Capacity (0-1,000 kVA)
8M-9	Limited Capacity (0-1,000 kVA)
8M-10	Limited Capacity (0-1,000 kVA)
Bracebridge TS	
24M-21	Limited Capacity (0-1,000 kVA)
Cherrywood TS	
81M-1	Limited Capacity (0-1,000 kVA)
81M-2	Limited Capacity (0-1,000 kVA)
81M-3	Limited Capacity (0-1,000 kVA)
81M-4	Limited Capacity (0-1,000 kVA)
81M-5	Limited Capacity (0-1,000 kVA)
81M-6	Limited Capacity (0-1,000 kVA)
81M-7	Limited Capacity (0-1,000 kVA)

TS Feeder	Remaining Capacity (kVA)
81M-8	Limited Capacity (0-1,000 kVA)
Enfield TS	
165M-3	Acceptable Capacity (2,001+ kVA)
165M-4	Acceptable Capacity (2,001+ kVA)
Port Hope TS	
50M-1	Acceptable Capacity (2,001+ kVA)
50M-3	Limited Capacity (0-1,000 kVA)
Thornton TS	
52M-1	Limited Capacity (0-1,000 kVA)
52M-6	Limited Capacity (0-1,000 kVA)
52M-7	Limited Capacity (0-1,000 kVA)
52M-8	Limited Capacity (0-1,000 kVA)
Whitby DESN 1 TS	
40M-5	Moderate Capacity (1,001-2,000 kVA)
40M-6	Moderate Capacity (1,001-2,000 kVA)
40M-7	Limited Capacity (0-1,000 kVA)
40M-8	Limited Capacity (0-1,000 kVA)
Whitby DESN 2 TS	
40M-21	Limited Capacity (0-1,000 kVA)
40M-22	Limited Capacity (0-1,000 kVA)
40M-23	Limited Capacity (0-1,000 kVA)
40M-24	Limited Capacity (0-1,000 kVA)
40M-25	Limited Capacity (0-1,000 kVA)
40M-26	Limited Capacity (0-1,000 kVA)
40M-27	Limited Capacity (0-1,000 kVA)
40M-28	Limited Capacity (0-1,000 kVA)
Wilson TS	
54M-11	Limited Capacity (0-1,000 kVA)
54M-14	Acceptable Capacity (2,001+ kVA)
54M-15	Acceptable Capacity (2,001+ kVA)
54M-17	Limited Capacity (0-1,000 kVA)

Table 24: Elexicon TS 27.6kV Feeder Remaining Capacity 2025

Feeder	Remaining Capacity (kVA)
Malvern TS	
26M-35	Acceptable Capacity (2,001+ kVA)
Seaton MTS	
SEATM-2	Acceptable Capacity (2,001+ kVA)
SEATM-4	Acceptable Capacity (2,001+ kVA)
SEATM-6	Limited Capacity (0-1,000 kVA)
SEATM-8	Acceptable Capacity (2,001+ kVA)
SEATM-10	Limited Capacity (0-1,000 kVA)
SEATM-12	Limited Capacity (0-1,000 kVA)
Sheppard TS	
47M-2	Limited Capacity (0-1,000 kVA)
47M-4	Limited Capacity (0-1,000 kVA)
Whitby DESN 1 TS	
40M-43	Acceptable Capacity (2,001+ kVA)
40M-44	Acceptable Capacity (2,001+ kVA)
40M-45	Limited Capacity (0-1,000 kVA)
40M-46	Moderate Capacity (1,001-2,000 kVA)
40M-47	Limited Capacity (0-1,000 kVA)
40M-48	Limited Capacity (0-1,000 kVA)

Table 25: Elexicon Municipal Substation Remaining Capacity 2025

MS	Remaining Capacity (kVA)
Ajax-Pickering	
Applecroft	Limited Capacity (0-1,000 kVA)
Dowty	Limited Capacity (0-1,000 kVA)
Monarch	Limited Capacity (0-1,000 kVA)
Notion	Limited Capacity (0-1,000 kVA)
Pickering Beach	Limited Capacity (0-1,000 kVA)
Westney Heights	Limited Capacity (0-1,000 kVA)
Bay Ridges	Limited Capacity (0-1,000 kVA)
Fairport	Limited Capacity (0-1,000 kVA)
Sandy Beach	Limited Capacity (0-1,000 kVA)
Squires Beach	Limited Capacity (0-1,000 kVA)
Town Centre	Limited Capacity (0-1,000 kVA)

MS	Remaining Capacity (kVA)
Whitby	
Taunton West	Limited Capacity (0-1,000 kVA)
Rossland East	Limited Capacity (0-1,000 kVA)
Thickson	Limited Capacity (0-1,000 kVA)
Rossland West	Limited Capacity (0-1,000 kVA)
Baldwin	Limited Capacity (0-1,000 kVA)
Garden	Limited Capacity (0-1,000 kVA)
W Lawler	Limited Capacity (0-1,000 kVA)
Victoria West	Limited Capacity (0-1,000 kVA)
Centre	Limited Capacity (0-1,000 kVA)
Conlin	Limited Capacity (0-1,000 kVA)
Taunton East	Limited Capacity (0-1,000 kVA)
Des Newman	Limited Capacity (0-1,000 kVA)
Clarington	
Bradshaw	Limited Capacity (0-1,000 kVA)
Liberty North	Limited Capacity (0-1,000 kVA)
Spry	Acceptable Capacity (2,001+ kVA)
Toronto	Acceptable Capacity (2,001+ kVA)
Wilmot	Acceptable Capacity (2,001+ kVA)
Belleville	
Bell	Limited Capacity (0-1,000 kVA)
Cascade	Limited Capacity (0-1,000 kVA)
Catharine	Limited Capacity (0-1,000 kVA)
Church	Limited Capacity (0-1,000 kVA)
Edgehill	Limited Capacity (0-1,000 kVA)
Harder	Limited Capacity (0-1,000 kVA)
Herchimer	Limited Capacity (0-1,000 kVA)
Jones	Limited Capacity (0-1,000 kVA)
Reid	Limited Capacity (0-1,000 kVA)
Riverside	Limited Capacity (0-1,000 kVA)
Sidney	Limited Capacity (0-1,000 kVA)
Brock	
Beaverton West	Acceptable Capacity (2,001+ kVA)
Main	Acceptable Capacity (2,001+ kVA)
William J Gillespie	Acceptable Capacity (2,001+ kVA)
Laidlaw	Acceptable Capacity (2,001+ kVA)
Sunderland	Acceptable Capacity (2,001+ kVA)

MS	Remaining Capacity (kVA)
Bigelow	Limited Capacity (0-1,000 kVA)
Crandell	Limited Capacity (0-1,000 kVA)
LR Mabley	Moderate Capacity (1,001-2,000 kVA)
Uxbridge East	Limited Capacity (0-1,000 kVA)
Uxbridge West	Limited Capacity (0-1,000 kVA)
Port Hope	
Cavan South	Moderate Capacity (1,001-2,000 kVA)
Cavan North	Acceptable Capacity (2,001+ kVA)
Howard Walker	Acceptable Capacity (2,001+ kVA)
James D Collins	Acceptable Capacity (2,001+ kVA)
Peacock	Acceptable Capacity (2,001+ kVA)
Shuter	Limited Capacity (0-1,000 kVA)
Gravenhurst	
Bay	Limited Capacity (0-1,000 kVA)
First	Limited Capacity (0-1,000 kVA)
James	Limited Capacity (0-1,000 kVA)

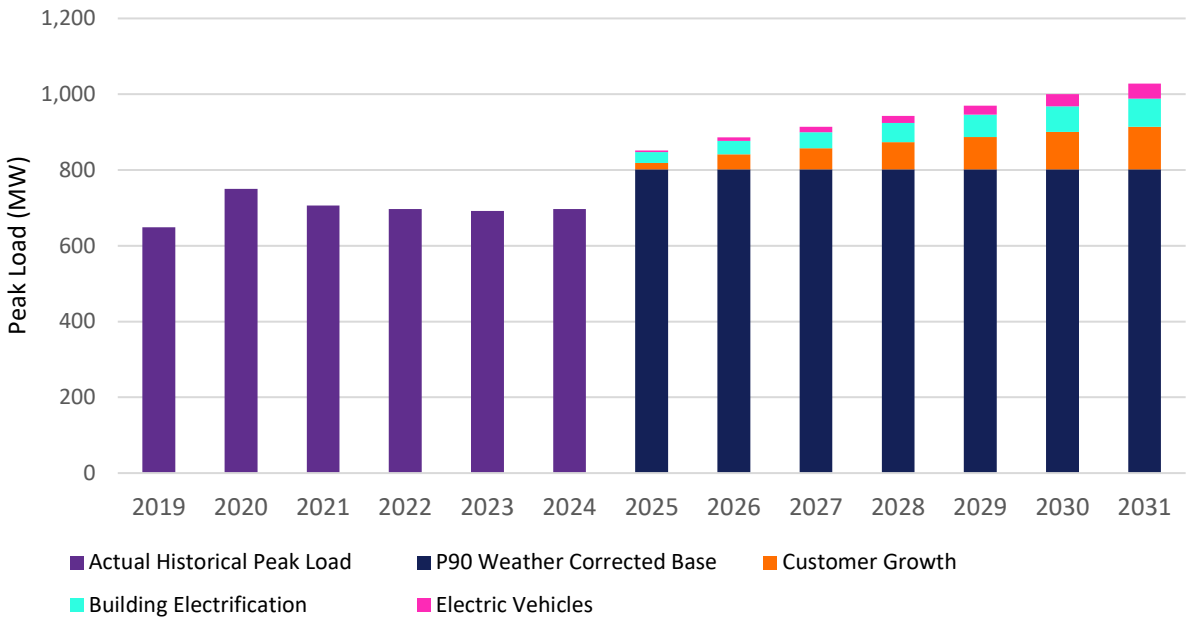
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System Peak Forecast Growth

The following section will outline the regional load growth results from the System Peak Load Forecast, which was detailed prior in Exhibit 2B – Tab 3 – Schedule 1. The load growth will be composed of the extreme weather P90 Weather Corrected Base load as the starting point, with projected customer growth, building electrification, and electric vehicle load impacts added on top. Historical peak loads throughout Elexicon's service territory have also been shown for the 2019-2024 periods. The system wide peak load shows the aggregate coincident peak of all respective regions. The historical loads are not necessarily growing year-over-year, even though Elexicon's customer base has been growing at a rate of approximately 1.4%. This is because loading is heavily impacted by weather conditions year over year, hence the requirement for a weather-corrected starting point for the forecast.

The Elexicon System Wide peak load forecast is shown in Figure 24 , posting an average 3.2% year over year growth in load in the 2025-2031 period. This growth, as previously mentioned, is heavily impacted by municipal secondary plans for mixed-use residential developments, large industrial customers, and ever-increasing electrification adoption.

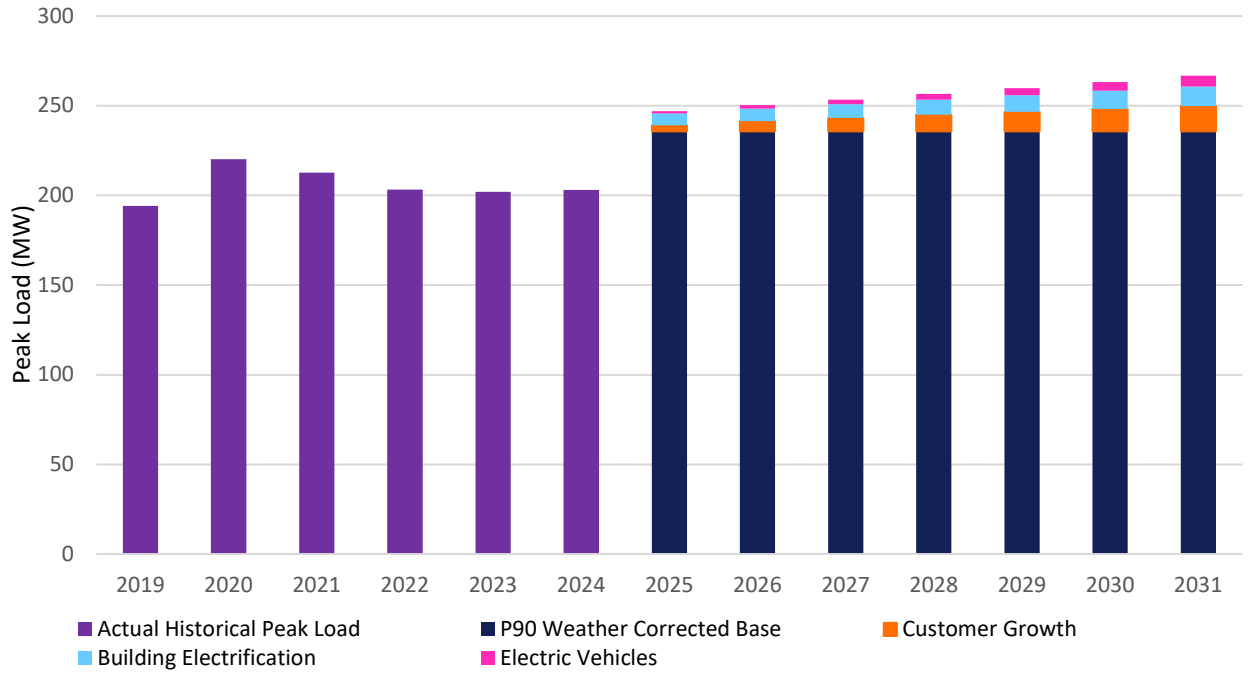
Figure 24: Elexicon System Peak Load Forecast (2019-2031)



Ajax-Pickering

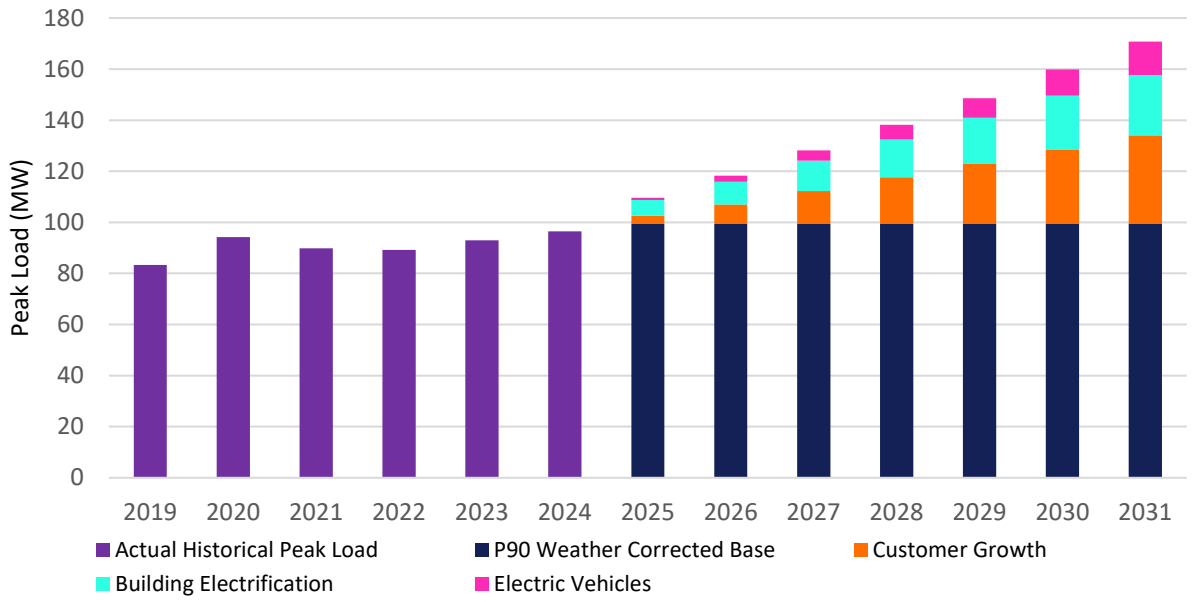
The Ajax-Pickering region is one of Elexicon's largest and most rapidly growing systems within its service territory. The region has been split into the 44kV and 27.6kV systems, to better showcase the impacts and Elexicon's future load growth plans. The 44kV system peak load forecast is shown in Figure 25, posting an average 0.7% year over year growth in load in the 2025-2031 period. This growth accounts for natural load growth with plans to direct the majority of future load onto the 27.6kV system. These plans are due to significant constraints in the 44kV TS LTR capacity as compared to the lighter loaded 27.6kV system.

Figure 25: Ajax-Pickering 44 kV System Peak Load Forecast Summer (2019 to 2031)



The Ajax-Pickering region's 27.6kV system peak load forecast is shown in Figure 26, posting an average 8.6% year over year growth in load in the 2025-2031 period. The 27.6kV system is absorbing the majority of projected load on both the 44kV and 27.6kV systems, and as a result is seeing nearly double the growth as compared to the other Elexicon regions. This growth is due in part to large industrial developments, as well as residential growth within specific communities.

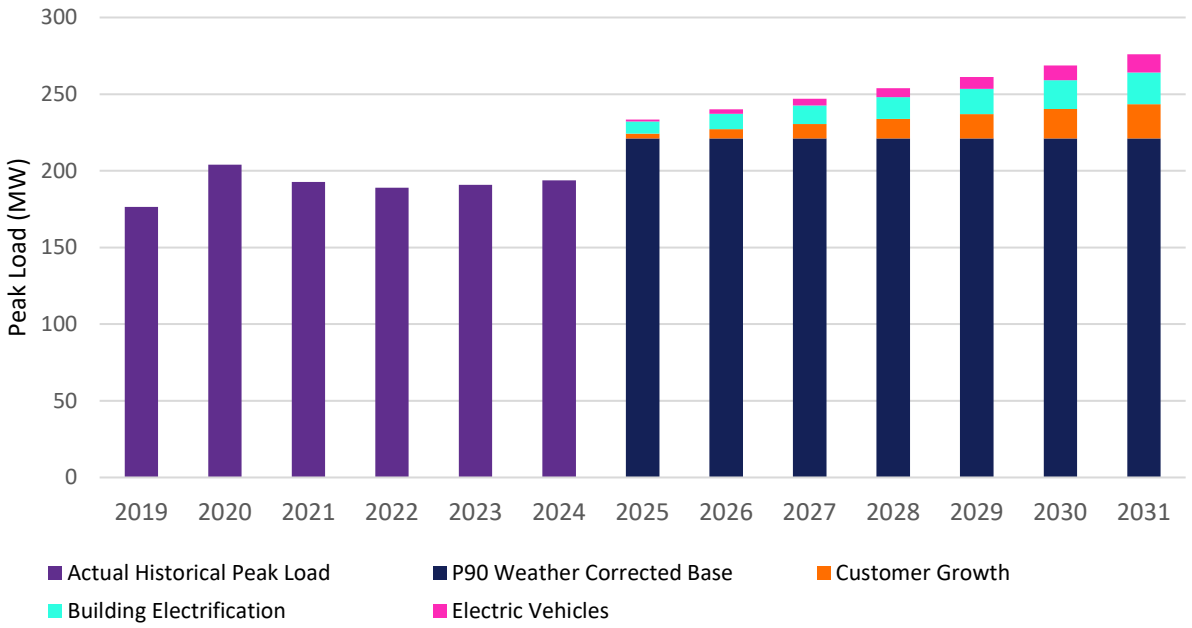
Figure 26: Ajax-Pickering 27.6 kV System Peak Load Forecast Summer (2019 to 2031)



Whitby

The Whitby region shares a border and multiple supply TS with Ajax-Pickering and has many similar growth trends. The region's 44kV system peak load forecast is shown in Figure 27, posting an average 2.8% year over year growth in load in the 2025-2031 period. This is similarly driven by industrial developments, as well as Secondary Plan forecast and realized commitments for residential mixed-use development in the North Brooklin area.

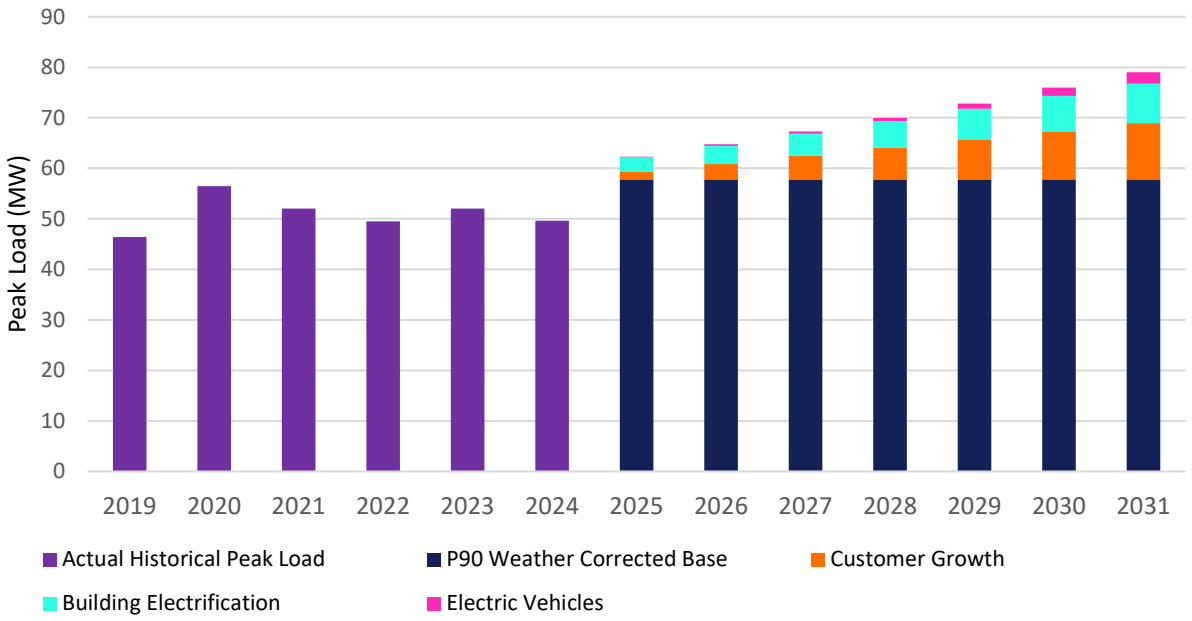
Figure 27: Whitby 44 kV System Peak Load Forecast Summer (2019 to 2031)



Clarington

The Clarington region's 44kV system peak load forecast is shown in Figure 28, posting an average 4.0% year over year growth in load in the 2025-2031 period.

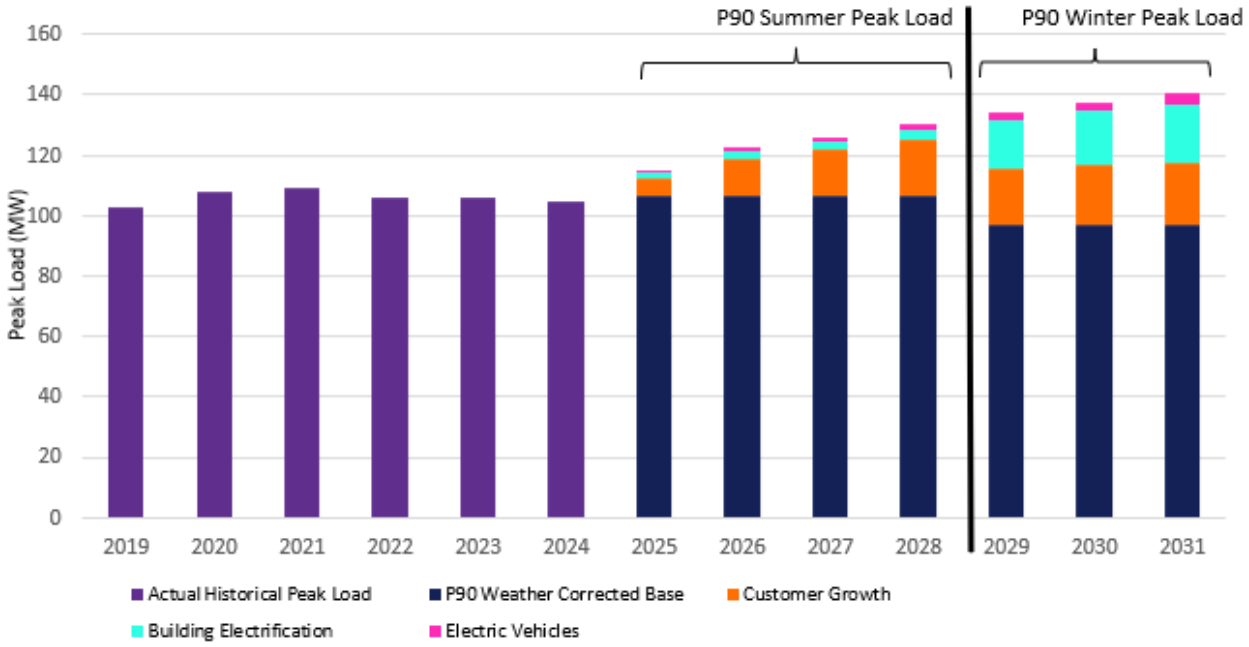
Figure 28: Clarington 44 kV System Peak Load Forecast Summer (2019 to 2031)



Belleville

The Belleville region's 44kV system peak load forecast is shown in Figure 29, posting an average 4.0% year over year growth in load in the 2025-2031 period. The system peak load forecast shows Elexicon's service territory in Belleville becoming winter peaking 2029 onwards, due mainly to building electrification impacts. The Belleville system is also significantly impacted by large committed industrial loads, as illustrated through the significant customer growth in the figure below.

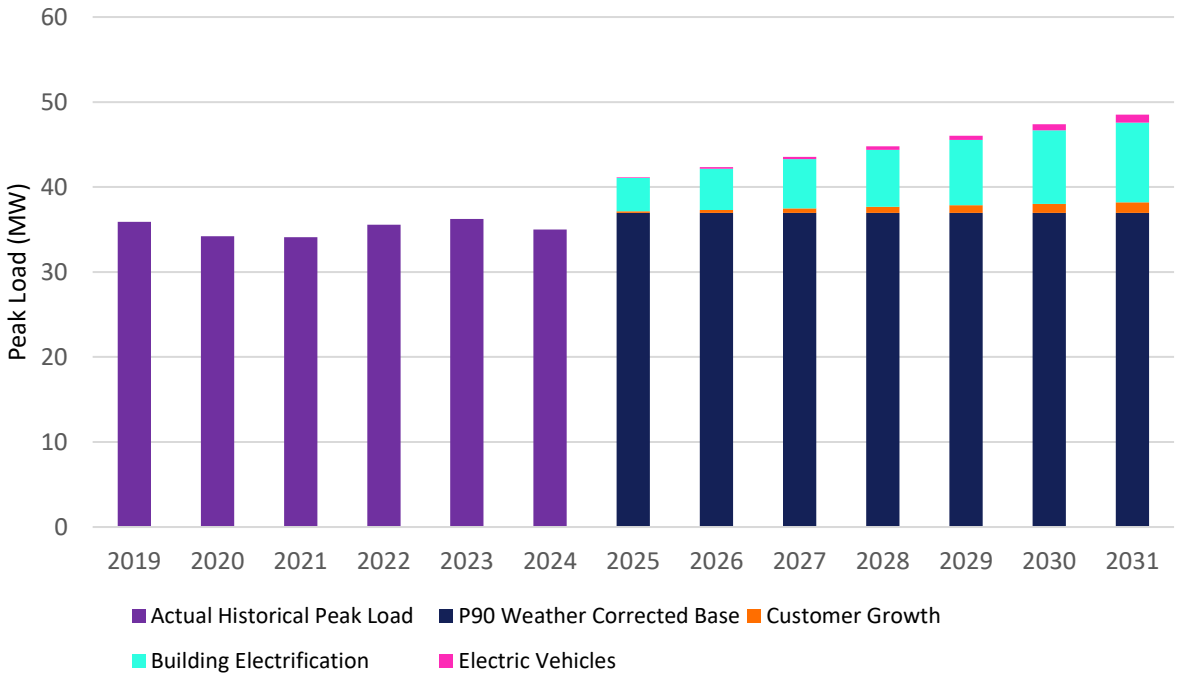
Figure 29: Belleville 44 kV System Peak Load Forecast Summer (2019 to 2031)



Port Hope

The Port Hope region's 44kV system peak load forecast is shown in Figure 30, posting an average 2.8% year over year growth in load in the 2025-2031 period. Port Hope is a winter-peaking region, and due to this there are more prevalent impacts noted from the projected uptake of electric space and water heating. Therefore, the building electrification load growth is more significant compared to other regions.

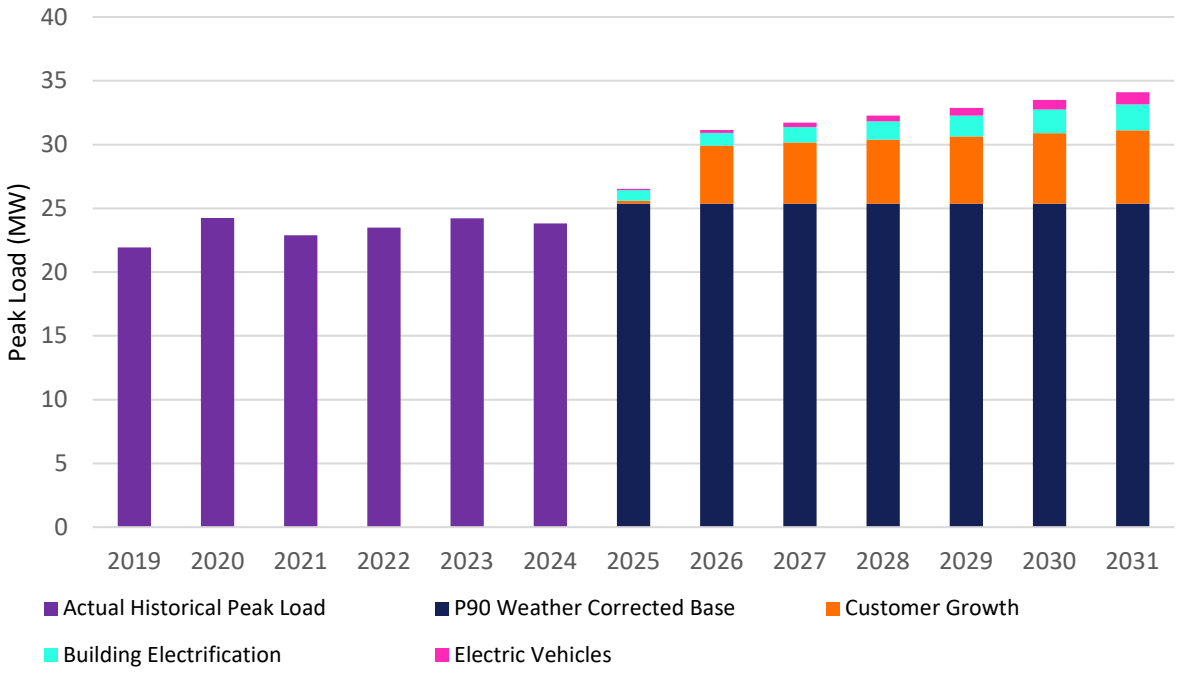
Figure 30: Port Hope 44 kV System Peak Load Forecast Winter (2019 to 2031)



Brock

The Brock region's 44kV system peak load forecast is shown in Figure 31, posting an average 4.4% year over year growth in load in the 2025-2031 period. This year-over-year growth is increased due to a 5 MW uptake of customer growth from a hospital and large residential developments in the Uxbridge region by the end of 2026. Otherwise, the Brock region will generally experience a more gradual growth rate.

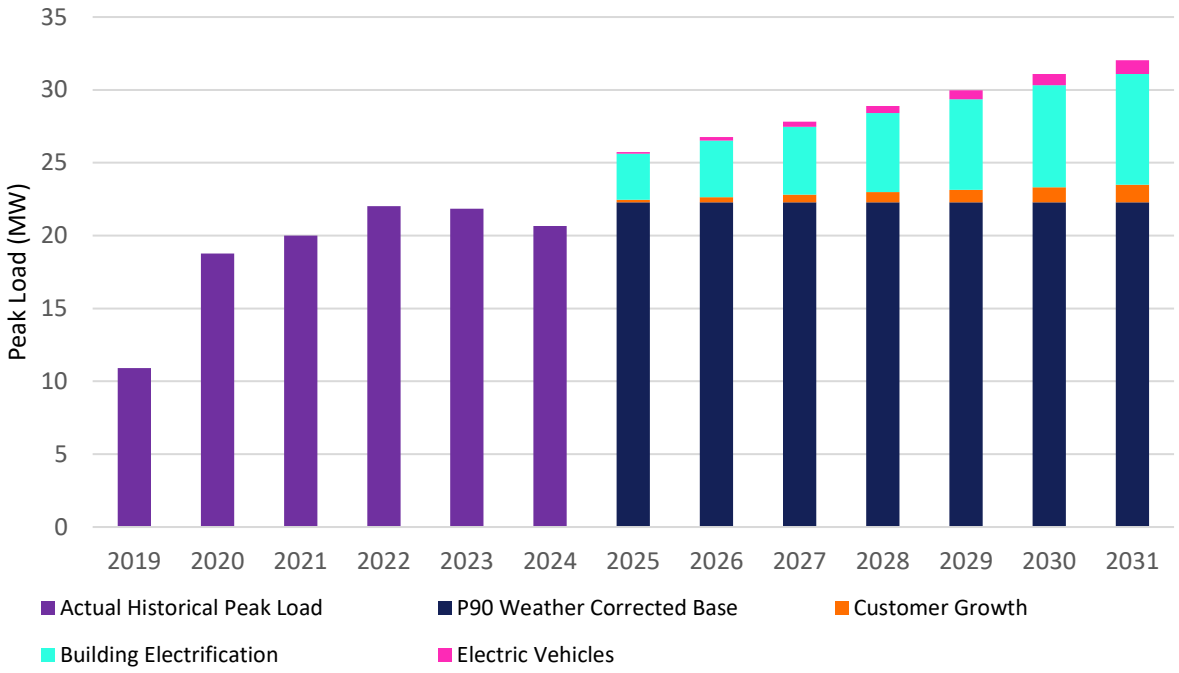
Figure 31: Brock 44 kV System Peak Load Forecast Summer (2019 - 2031)



Gravenhurst

The Gravenhurst region's 44kV system peak load forecast is shown in Figure 32, posting an average 3.7% year over year growth in load in the 2025-2031 period. Gravenhurst is a winter-peaking region, and due to this there are more prevalent impacts noted from the projected uptake of electric space and water heating. Therefore, the building electrification load growth is more significant compared to other regions.

Figure 32: Gravenhurst 44 kV System Peak Load Forecast Winter (2019 - 2031)



Investments Addressing Capacity Constraints

To address the capacity constraints identified above, System Access investments have been planned. The 2027 to 2031 period will see the addition of 101 MVA of Distribution System Capacity, and 180 MVA of Substation Supply Capacity by the end of 2031. This represents a 12% increase in Distribution System Capacity and a 14% increase in Substation Supply Capacity throughout the Elexicon Service Territory. The Substation Growth and Substation Renewal narratives (Exhibit 2B - Tab 4 - Schedule 3 – Appendix E and I) highlight the specific investments made in more detail.

As shown in Table 26, planned investments through the end of 2031 will reduce the number of MSs with limited capacity by 23, increasing the proportion of MSs with acceptable capacity from 21% in 2025 to 60% by 2031. However, if customer connections and load grow at a rate faster than anticipated, the remaining capacity at substations could be further constrained.

Table 26: Elexicon Overall System Capacity by Municipal Substation 2025 vs. End of 2031

Capacity	Number of MSs		
	2025 State	End of 2031 State without Investments	End of 2031 State with Investments
Limited Capacity (0 – 1,000 kVA)	44	47	21
Moderate Capacity (1,001 – 2,000 kVA)	2	2	3
Acceptable Capacity (2,001+ kVA)	12	9	36

The following sections will dive into the individual regions and highlight the noticeable impacts that will result from the 2027 to 2031 DSP investments.

Ajax-Pickering

The MSs in Table 27 have limited capacity in 2025 due to the TS LTR constraints on the 44kV TSs supplying the Ajax-Pickering region. Elexicon's planned substation investments involve the construction of a new GTA East TS in North Pickering / North Whitby by the end of 2031 (further details can be found in Exhibit 2B - Tab 4 - Schedule 3 – Appendix I, Substation Growth Program). The addition of the GTA East TS and associated feeder enhancements will provide additional Substation Supply Capacity for the Ajax-Pickering region, and as a result will alleviate majority of the downstream constraints. This will result in available capacity at 10 of the 11 MSs in Ajax-Pickering region. The remaining limited capacity substation in 2031, Bay Ridges MS, will remain constrained due to the MS transformer limitation, which will be further investigated in the post-2031 investment plan.

Table 27: Ajax-Pickering Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Applecroft	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Dowty	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Monarch	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Notion	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Pickering Beach	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Westney Heights	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Bay Ridges	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Fairport	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Sandy Beach	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Squires Beach	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Town Centre	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)

Whitby

The Whitby region is similarly constrained to Ajax-Pickering, and the majority of the substations in Table 28 are limited in 2025 due to the TS LTR or TS feeder constraints on the 44kV TSs supplying the Whitby region. Elexicon's planned substation investments involve the construction of a new GTA East TS in North Pickering / North Whitby by the end of 2031 (further details can be found in Exhibit 2B - Tab 4 - Schedule 3 – Appendix I, Substation Growth Program). The addition of the GTA East TS and associated feeder enhancements will provide additional Substation Supply Capacity for the Ajax-Pickering region, and as a result will alleviate majority of the downstream constraints. This will result in available capacity at 8 of the 12 MSs in the Whitby region. The remaining limited capacity substations will remain constrained by the TS feeder from Thornton TS and MS transformer limitations at Taunton West MS. These capacity constraints will be further investigated in the post-2031 investment plan.

Table 28: Whitby Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Taunton West	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Rossland East	Limited Capacity (0-1,000 kVA)	Moderate Capacity (1,001-2,000 kVA)
Thickson	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Rossland West	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Baldwin	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Garden	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
W Lawler	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Victoria West	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Centre	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Conlin	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Taunton East	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Des Newman	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Winchester West	N/A[23]	Acceptable Capacity (2,001+ kVA)

[23] Brooklin North is a new station in the 2027 to 2031 investment plan

Clarington

The MSs in Clarington region, shown in Table 29, are currently limited by one of the TS feeders. For the 2027-2031 term, there are no investments being made to gain additional capacity on the TS feeder, however Elexicon is managing the risk of capacity constraints in the region and will continue to meet with Hydro One to discuss solutions to relieve the TS Feeder capacity constraints. To maintain the Distribution System Capacity, Elexicon will upgrade Bradshaw MS, and further details can be found in Exhibit 2B - Tab 4 - Schedule 3 – Appendix I, Substation Growth Program.

Table 29: Clarington Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Bradshaw	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Liberty North	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Spry	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Toronto	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Wilmot	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)

Belleville

The Belleville region, shown in Table 30, has capacity constraint limitations at all three levels; however, a large portion are limited by the TS LTR. The investment being made, that is relieving capacity limitations for a portion of the MS, is the construction of an additional DESN at Belleville TS, called Belleville DESN 2. This, however, is being completed by end of 2026 and captured in Elexicon's 2026 ICM application, outside of this 2027-2031 DSP. Investments at the MS level, including the rebuild of Edgehill MS or new build of Foster MS, have also supported keeping the MS in the acceptable capacity range. The MSs that remain at limited capacity are due to load growth and continued voltage conversion efforts, in which investments will be required past 2031 to support.

Table 30: Belleville Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Bell	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Cascade	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Catharine	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Church	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Edgehill	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Harder	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Herchimer	Limited Capacity (0-1,000 kVA)	Substation Decommissioned
Jones	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Reid	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Riverside	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
Sidney	Limited Capacity (0-1,000 kVA)	Moderate Capacity (1,001-2,000 kVA)
Foster	N/A[24]	Acceptable Capacity (2,001+ kVA)

[24] Foster is a new station in the 2027 to 2031 investment plan

Brock

The Brock region encompasses the municipalities of Sunderland, Beaverton, Cannington, Port Perry, and Uxbridge. The constraints are more prominently found in Port Perry and Uxbridge, with a combination of MS transformer and TS feeder limitations. The investment in the rebuilding of Crandell MS is bringing this substation from limited to acceptable capacity. Post-2031, Elexicon will need to make future investments to add another TS feeder to the Township of Uxbridge and to upsize the transformers within Port Perry to further relieve capacity constraints.

Table 31: Brock Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Beaverton West	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Main	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
William J Gillespie	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Laidlaw	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Sunderland	Acceptable Capacity (2,001+ kVA)	Moderate Capacity (1,001-2,000 kVA)
Bigelow	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Crandell	Limited Capacity (0-1,000 kVA)	Acceptable Capacity (2,001+ kVA)
LR Mabley	Moderate Capacity (1,001-2,000 kVA)	Limited Capacity (0-1,000 kVA)
Uxbridge East	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Uxbridge West	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Uxbridge North	N/A[25]	Limited Capacity (0-1,000 kVA)

[25] Uxbridge North is a new station in the 2027 to 2031 investment plan

Port Hope

The Port Hope region, shown in Table 32 is currently limited by one of the TS feeders supplying Elexicon's MSs. For the 2027-2031 term, there are no investments being made to gain additional capacity on the TS feeder, however Elexicon is managing the risk of capacity constraints in the region and will continue to meet with Hydro One to discuss solutions to relieve the TS Feeder capacity constraints. To support the Distribution System Capacity, Elexicon is building a new 27.6kV substation, Port Hope 27.6kV MS, further details can be found in Exhibit 2B - Tab 4 - Schedule 3 – Appendix I, Substation Growth Program.

Table 32: Port Hope Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Cavan South	Moderate Capacity (1,001-2,000 kVA)	Substation Decommissioned
Cavan North	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Howard Walker	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
James D Collins	Acceptable Capacity (2,001+ kVA)	Limited Capacity (0-1,000 kVA)
Peacock	Acceptable Capacity (2,001+ kVA)	Acceptable Capacity (2,001+ kVA)
Shuter	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
Port Hope 27.6kV	N/A[26]	Acceptable Capacity (2,001+ kVA)

[26] Port Hope 27.6 kV MS is a new station in the 2027 to 2031 investment plan

Gravenhurst

The Gravenhurst region, shown in Table 33 , is currently limited by the single TS feeder supplying Elexicon's MSs. For the 2027-2031 term, there are no investments being made to gain additional capacity on the TS feeder, however Elexicon is managing the risk of capacity constraints in the region and will continue to meet with Hydro One to discuss solutions to relieve the TS Feeder capacity constraints.

Table 33: Gravenhurst Overall System Capacity by Municipal Substation 2025 vs. End of 2031 with Investments

MS	Remaining Capacity (kVA) - 2025	Remaining Capacity (kVA) – End of 2031 with Investments
Bay	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
First	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)
James	Limited Capacity (0-1,000 kVA)	Limited Capacity (0-1,000 kVA)

3. TRANSMISSION OR HIGH VOLTAGE ASSETS

Elexicon owns equipment at voltages >50 kV located at the Seaton Municipal Transformer Substation, which includes:

- 230kV Primary Switches
- 230kV Grounding Switches
- 230kV Surge Arrestors
- 230kV Open Air Bus Structure
- 230kV CVT's
- 215.5kV:28.0 kV 75/100/125 MVA Substation Transformers

4. HOST & EMBEDDED DISTRIBUTORS

There are various configurations of host and embedded status across Elexicon's service territory. In some cases, Elexicon is an embedded distributor and in other cases Elexicon is a host distributor. Regular quarterly touchpoints have been set up with Hydro One Distribution, the main host LDC where Elexicon is

embedded, to discuss capacity limitations on embedded feeders. Following are descriptions of all cases and feeders where embedded or host status occurs. Table 34 to Table 37 below detail all the host and embedded configurations.

Table 34: Elexicon Embedded to Hydro One Distribution Owned Feeder

Host Distributor - Hydro One Distribution		
Embedded Distributor - Elexicon Energy		
Feeder Name	Substation Name	Voltage (kV)
ORONF3	Orono DS	8.32
41M-22	Armitage TS	44
31M-24	Beaverton TS	44
31M-29	Beaverton TS	44
31M-30	Beaverton TS	44
24M-21	Bracebridge TS	44
165M-3	Enfield TS	44
165M-4	Enfield TS	44
26M-35	Malvern TS	27.6
50M-1	Port Hope TS	44
50M-3	Port Hope TS	44
47M-2	Sheppard TS	27.6
47M-4	Sheppard TS	27.6
54M-11	Wilson TS	44
54M-14	Wilson TS	44
54M-15	Wilson TS	44
54M-17	Wilson TS	44

Table 35: Elexicon Embedded to Lakeland Power Feeder

Host Distributor - Lakeland Power		
Embedded Distributor - Elexicon Energy		
Feeder Name	Substation Name	Voltage (kV)
MSFLF3	Muskoka Falls DS	12.47

Table 36: Elexicon Embedded to Hydro One Distribution Owned Municipal Substation

Host Distributor - Hydro One Distribution		
Embedded Distributor - Elexicon Energy		
Feeder Name	Substation Name	Voltage (kV)
GRAVF2	Gravenhurst DS	12.47
JRDSF2	Jones DS	12.47
JRDSF3	Jones DS	12.47
WALKF3	Walkers Point DS	12.47

Table 37: Hydro One Distribution Embedded to Elexicon Distribution Feeder

Host Distributor - Elexicon Energy		
Embedded Distributor - Hydro One Distribution		
Feeder Name	Substation Name	Voltage (kV)
GRAVF1	Gravenhurst DS	12.47
GRAVF3	Gravenhurst DS	12.47
JRDSF1	Jones DS	12.47

5. LIST OF ATTACHMENTS:

- Appendix A: Elexicon's Grid Modernization Plan
- Appendix B: Asset Condition Assessment – Final Report

elexicon ENERGY



Appendix A
Elexicon's Grid Modernization Plan

2027-2031

ELEXICON'S GRID MODERNIZATION PLAN

1. BACKGROUND

Elexicon's vision is "To empower the communities we serve and help customers seize opportunities to ignite a better future" with a mission "To provide our customers with reliable, affordable energy services and continuously improve to meet their needs, while ensuring the needs of our shareholders are met through sustainable growth." To effectively achieve these objectives, Elexicon must continue investing in grid modernization technologies that enhance grid reliability, resiliency, and respond to the evolving needs of customers.

Elexicon is investing in a comprehensive portfolio of technologies including SCADA-Enabled Switches & Reclosers, Communicating Fault Circuit Indicators (CFCIs), Self-Resetting Fuses, Station Modernization, Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI 2.0), Distributed Energy Resource Management System (DERMS), enhanced data analytics platforms, and supporting operational technologies to address the converging challenges of system reliability performance, climate-induced system stress, sustained load growth from customer growth and electrification, evolving customer expectations, and the growing complexity introduced by distributed energy resources (DERs).

The distribution system is experiencing the effects of rising electrification through electric vehicles (EVs) and electrified heating, along with a growing number of customer-owned DER installations such as rooftop solar and Battery Energy Storage Systems (BESS). They are actively shaping system operations through changing load patterns and increased requirements for real-time monitoring and control. Continued investment in grid modernization is therefore essential to maintain reliable service under these present and accelerating conditions.

Elexicon's Grid Modernization Plan prioritizes customer-focused technologies that deliver near-term reliability and resiliency improvements, reduce outage duration, improve fault location accuracy, enhance grid visibility, and support more efficient switching and service restoration. While a portion of the plan prepares the system for deeper DER integration over time, this readiness is grounded in observable trends

and aligns with provincial policy direction. The focus remains on ensuring that Elexicon can safely and efficiently manage bi-directional power flows, maintain power quality, and uphold system reliability as customer behaviour and technology adoption continue to evolve.

Collectively, these investments position Elexicon to provide safe, reliable, and cost-effective electricity services, strengthen resilience in the face of climate-related events, support decarbonization efforts, and improve overall customer experience.

2. IMPERATIVES FOR GRID MODERNIZATION

Elexicon's most immediate imperative for grid modernization is to improve service reliability and strengthen system resiliency. Customer expectations are evolving, particularly as customers grow more conscious to power interruptions and the critical role electricity plays in their daily lives and business operations. Strengthening reliability and resiliency is an operational priority, driven by the combined challenges of aging, deteriorating infrastructure and the growing frequency and intensity of adverse weather events. Modernized switching, improved system visibility, and automated fault response enable faster recovery from service disruptions and minimize customer impacts during outage events. These measures directly enhance the grid's ability to withstand and respond to system stresses while maintaining critical service continuity.

Grid modernization investments also generate near-term operational efficiencies that contribute to improved cost-effectiveness. Technologies such as SCADA-enabled switches, CFCIs, self-resetting fuses, and AMI 2.0 reduce the number of truck rolls required for fault investigation and manual switching, shorten field response times, and decrease the reliance on manual patrols to locate outages. Improved fault detection, remote switching capability, and enhanced situational awareness support more targeted and efficient deployment of field crews, reducing OM&A expenditures associated with outage response.

Beyond the near-term operational benefits, the distribution system is experiencing broader transformation driven by electrification and changing customer behaviour. The continued adoption of EVs, electrified heating, and customer-owned DERs is altering load profiles and introducing new variability into day-to-day operations. These changes require improved monitoring, situational awareness, and automation to ensure service reliability is maintained as demand continues to grow.

From a policy and regulatory perspective, Elexicon must remain aligned with provincial direction that encourages efficient integration of DERs and supports long-term planning that anticipates the needs of growing communities. As one of the fastest-growing distributors in Ontario, Elexicon requires an approach that balances immediate reliability and resiliency improvements with prudent preparation for continued electrification and the steady rise of bi-directional power flows.

Customer-owned generation and energy storage is already present across the service territory, and connection activity continues to increase. These resources introduce operational complexity that must be managed through enhanced visibility, voltage control, and protection coordination. Grid modernization ensures that DERs are integrated in a manner that maintains safety, preserves reliability, and optimizes system performance.

Feedback from Elexicon's customer engagement survey underscored strong support for investments in Grid Modernization with 73% of residential, 81% of seasonal, 71% of small business, and 88% of GS>50 kW customers indicating support for investment in this area (Refer to Exhibit 1 Tab 7). This demonstrates that customers across the board recognize the importance of investing in technologies that improve system reliability, resiliency, and adaptability to emerging needs such as electrification and DER integration.

Collectively, these factors demonstrate that grid modernization is a necessary and timely response to both current and emerging system needs. The investments outlined in this plan directly support improved reliability, strengthened resiliency, and more efficient operations, while ensuring that the distribution system remains capable of accommodating the technologies and customer behaviours already taking shape across Elexicon's service territories. By advancing these initiatives, Elexicon can continue to provide safe, reliable, and cost-effective service while preparing the grid for sustained growth and evolving energy demands.

3. DRIVERS & OBJECTIVES

While Elexicon has initiated the modernization of its grid and has made measurable progress, the pace of implementation has remained modest relative to peer utilities, due to the challenges articulated in the 2027-2031 Distribution System Plan (DSP).

3.1 Grid Modernization Plan Drivers

In the 2027-2031 period, Elexicon's grid modernization plan entails an accelerated pace of investments in scaling proven technologies to provide near and long-term reliability, resiliency and efficiency benefits. These include:

- SCADA-Enabled Switches & Reclosers, CFCIs, and Self-Resetting Fuses to enhance reliability and resiliency.
- Temperature Monitoring with fibre technology to support proactive asset management.
- AMI 2.0 to enhance visibility and situational awareness at the edge of the grid, enabling more accurate load profiling, outage detection, and customer-level diagnostics.
- Operational Technology (OT) Enablers to support automation, interoperability, and real-time situational awareness:
- ADMS module enhancements such as load forecasting, voltage optimization and Fault Location, Isolation and Service Restoration (FLISR) expansions.
- Enterprise Service Bus to support real-time integration between OT systems and SAP S/4HANA.
- Communication system upgrades including SCADA radio, Multiprotocol Label Switching (MPLS) / Access Point Name (APN) expansion, and backhaul network modernization to support secure, real-time device connectivity.
- Geographic Information System (GIS) modernization to enhance network modelling and system integration.
- An incremental test-and-learn approach for emerging solutions and investments to address future expectations with respect to the integration of DERs, and increased load growth resulting from electrification of the grid as well as customer growth within the region.
- DERMS to coordinate decentralized generation and storage.

- Distribution System Operator (DSO) enablement modules to support bi-directional power flow and local energy markets.
- Grid-Edge Visibility Tools and Advanced Analytics platforms to inform planning and operational flexibility.

3.2 Grid Modernization Plan Objectives

The objectives of Elexicon's Grid Modernization Plan are influenced by the following drivers:

- **Reliability:** The need to enhance outage performance metrics (i.e. SAIDI and SAIFI) and operational response capabilities to meet customer expectations and system performance standards.
- **Resiliency:** The need to strengthen the grid's ability to withstand and recover from major weather events and other system disruptions, minimizing service interruptions and accelerating restoration efforts.
- **Efficiency:** The need to improve operational efficiency and reduce operating and maintenance expenditures associated with outage response.
- **Load Growth:** Increasing electricity demand driven by the adoption of EVs, electrified heating, and population growth across Elexicon's service territory.
- **DER Integration:** Need to support both customer expectations and government policy objectives by enabling the integration of local generation and storage, allowing customers to participate in energy markets and offset electricity costs.
- **Safety:** Growing risk of faults and equipment-related incidents that endanger workers and the public, particularly as the grid becomes more complex and heavily loaded.

As Elexicon Energy advances its grid modernization plan, a series of clearly defined objectives have been established to ensure that investments deliver measurable value across key performance areas. Table 1 below outlines the strategic objectives that guide Elexicon's investment decisions and underpin the delivery of a modern, responsive, and future-ready distribution system.

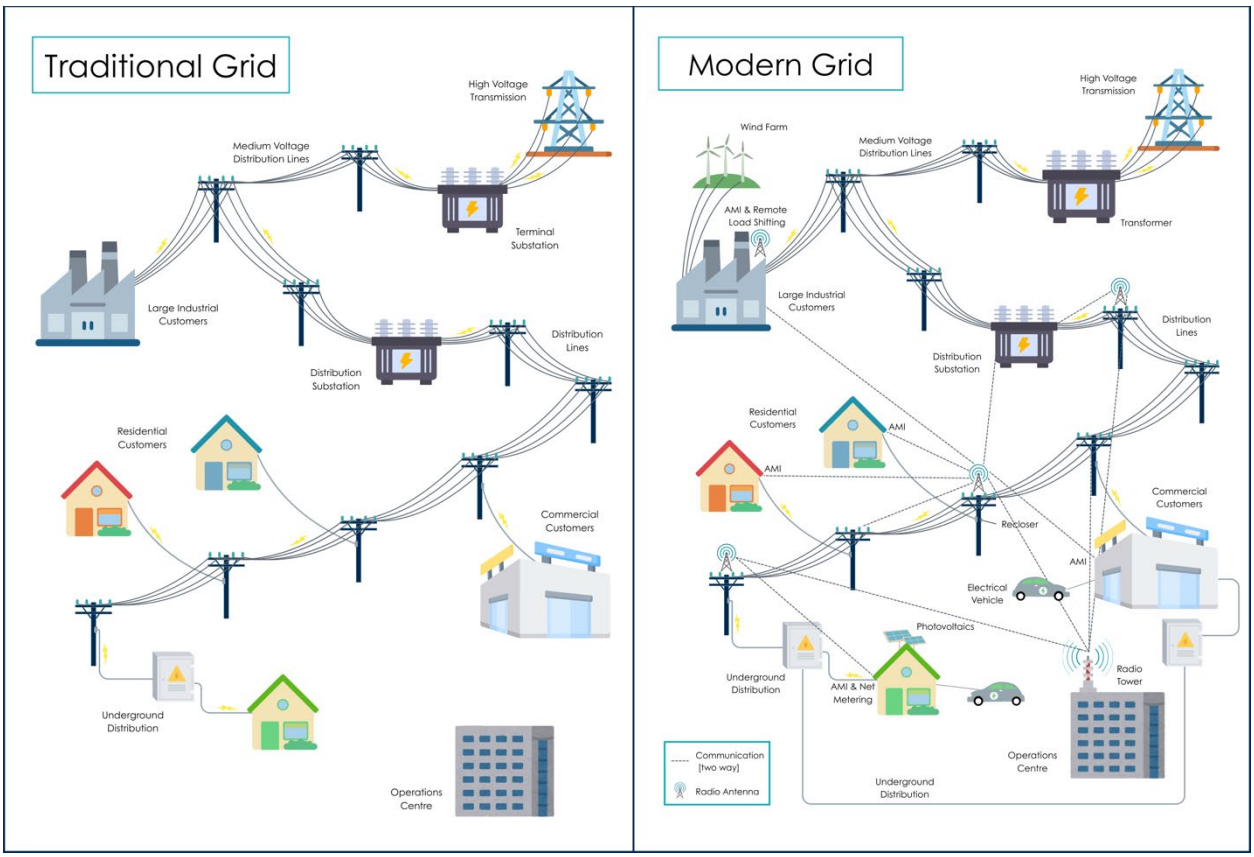
Table 1: Grid Modernization Plan Objectives

Improvement Type	Grid Modernization Objectives
Reliability Improvements	• Support SAIDI and SAIFI performance through automation and monitoring technologies. • Enhance grid visibility to enable faster fault detection and location. • Strengthen system operator control of grid and protection devices to enable faster switching, more precise operational response, and improved restoration.
Enhanced Resiliency	• Develop a self-healing grid capable of automatically detecting faults, isolating affected sections, and restoring service without manual intervention. • Improve response to severe weather and unplanned events through advanced fault location technologies and control systems. • Strengthen the grid's ability to reroute power and maintain service during system disruptions with minimal manual intervention. • Minimize restoration times and reduce customer impacts during major outages.
Improved Efficiency	• Reduce operating and maintenance expenditures associated with outage response by decreasing the need for manual switching, fault patrols, and truck rolls through automated fault detection and remote-control capabilities. • Improve workforce utilization by enabling more targeted and efficient deployment of field crews based on real-time system visibility and accurate fault location.
Support Load Growth	• Accommodate rising demand from electrification, including EVs and electrified heating, by ensuring operational visibility and flexibility. • Mitigate the risk of feeder and transformer overloading through proactive monitoring, load balancing, and automation. • Preserve service reliability and power quality amidst increasing peak demand and greater reliance on uninterrupted electricity supply.
Improved Customer Experience	• Provide real-time updates to customers during outages, offering transparency and reducing uncertainty.
Grid Readiness for DER Enablement and Integration	• Enable the reliable and scalable integration of DERs. • Enable achievement of provincial decarbonization goals and align with customer expectations by creating a flexible and future-ready distribution network.

Improvement Type	Grid Modernization Objectives
	• Modernize grid infrastructure to support two-way power flows and real-time monitoring of DERs. • Establish system visibility and control associated with solar, wind, and other DERs. • Ensure interoperability with DERMs and other grid-edge technologies.
Safety	• Increase automated responses to outages through the use of fault isolation and restoration technologies (FLISR), minimizing worker exposure to hazardous conditions.

4. ELEXICON'S GRID MODERNIZATION PLAN

Figure 1: Graphical Comparison of Traditional vs Modern Grid



Elexicon's grid modernization plan involves targeted investments in enhancing grid visibility, automation and control to transform the existing grid into a more reliable, resilient, and efficient system. To achieve this vision, Elexicon's grid modernization plan follows a structured, phased approach that ensures investments are sequenced to maximize benefits for customers while preparing for the evolving energy landscape.

Elexicon recognizes that grid modernization is an evolving discipline and that technologies, customer needs, and system priorities will continue to develop over time. While the outlined plan establishes a clear and structured path forward, it will be continuously reviewed and refined to reflect emerging technologies, changing policy expectations, and operational insights gained through implementation. As conditions change and new opportunities arise, Elexicon will revisit and update its modernization activities to ensure that investments remain aligned with system needs, customer expectations, and long-term strategic objectives.

4.1 Phase 1 of Plan (2025-2031)

This phase focuses on strengthening grid reliability, resiliency, visibility, automation and operational efficiency. Key initiatives include the deployment of SCADA-Enabled Switches & Reclosers, CFCIs, Self-Resetting Fuses, Station Modernization, AMI 2.0 and the supporting OT enablers that provide the digital foundation for advanced monitoring and control. Together, these initiatives enable real-time monitoring, proactive outage management, and improve system reliability & resiliency. These foundational steps set the stage for a more intelligent and responsive grid.

4.2 Phase 2 of Plan (2032+)

Building on the foundational technologies implemented in Phase 1, this phase will focus on expanding the deployment of these technologies across all areas. As these technologies mature and become fully embedded in operations, the focus will continue with grid reliability, resiliency and optimizing grid performance through increased integration of DERs, while supporting advanced customer participation models, enabling higher levels of bi-directional power flow, decentralized generation, and demand-side management.

Table 2 below summarizes Elexicon's planned capital investments within the 2027-2031 period that collectively support the implementation of the grid modernization plan.

Table 2: 2027-2031 Grid Modernization Capital Investments by Program

Program	Technology	Total
S2 Grid Enhancements	CFCIs	$2.15M
	SCADA-Enabled Switches	$3.98M
	Self-Resetting Fuses	$2.26M
	Reclosers	$4.73M
	Station Modernization	$7.65M
A4 Metering/AMI 2.0	AMI 2.0	$21.39M
P5 OT Systems	OT System upgrades, ADMS/DERMs, OT Grid Modernization	$17.53M
	Total	$59.69M

Refer to Section 5.4 of the DSP for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

Table 3 below presents the expected progression of Elexicon's grid modernization journey, contrasting current state of the distribution system with the direction in which it is advancing. The future state represents an on-going progression rather than a defined point in time, reflecting continuous modernization as technologies mature, customer expectations evolve, and system needs change. Elexicon's phased approach acknowledges that transformative capabilities will be introduced incrementally and will continue to develop well beyond the 2031 planning horizon.

Table 3: Current (2025) vs. Evolving Future State

Feature	Current	Evolving Future State
Grid Visibility	Limited real-time data	High visibility with real-time monitoring and control.
Resilience	Vulnerable to extreme weather and disruptions	Strengthened resilience through automation, advanced control systems, and decentralized generation.
Outage Response	Reactive, manual restoration	Remote and automated fault detection and isolation.
Digital Technologies	Minimal	Advanced technologies (ADMS, DERMS, FLISR, Self-Resetting Fuses)

Feature	Current	Evolving Future State
Technology	Electromechanical, limited communication	Digital, enables communication and self-regulation.
Sensors	Few sensors, limited fault detection	Widespread deployment of advanced sensors (e.g., AMI 2.0, CFCI, temperature monitoring) enabling precise fault detection and efficient power rerouting.
Flexibility and Scalability	Rigid, limited flexibility	Highly flexible and scalable to future energy needs
Power Flow	Limited bi-directional (primarily from centralized generation)	Bi-directional (supports DERs and decentralized generation)
Generation Model	Centralized (Nuclear, Hydro)	Distributed generation, including renewables (solar, wind, BESS)
Customer Role	Passive consumers	Active participants (prosumers, demand response)
Energy Storage Integration	Limited or non-existent	Full integration of energy storage for load balancing and grid stability
Environmental Impact	High GHG emissions	Enable GHG emission reductions, supports decarbonization

Elexicon has already taken foundational steps toward grid modernization through investments in automation, remote switching, and real-time monitoring. Key initiatives include the deployment of SCADA-enabled Switches and Reclosers, CFCIs, and Self-Resetting Fuses to enhance fault detection and service restoration. These investments demonstrate that Elexicon is on a path toward a more reliable, resilient and intelligent grid, but continued and accelerated investment is required to scale these technologies and meet the growing challenges posed by system reliability, electrification, climate change, and bi-directional energy flows.

5. ORGANIZATIONAL ENABLERS OF GRID MODERNIZATION

Elexicon's Grid Modernization Plan is a cross-functional initiative that draws on the collective capabilities of Asset Management, Digital & Innovation, Operations, and the System Control Centre. Together, these business functions support the planning, design, implementation, and continuous improvement of Elexicon's modernization efforts. While the plan is collaboratively governed, the successful delivery of the portfolio relies not on individuals but on the alignment of resources, skills, business processes, and OM&A program structures that underpin Elexicon's capacity to execute.

Grid modernization is not a standalone function; it is embedded across several capital and maintenance programs and is supported by integrated workforce planning. The plan requires ongoing investment in engineering expertise, data analytics capabilities, program management resources, system planning, system control centre and field operations.

Specific capabilities required to deliver on the modernization plan include:

5.1 Asset Management

Asset Management leads investment planning, lifecycle analysis, and the integration of grid modernization within long-term capital and asset renewal strategies.

5.2 Digital and Innovation

Digital and Innovation provides technology enablement, including ADMS, SCADA, analytics platforms, and systems integration to support automation, visibility, and digital controls.

5.3 Operations

Operations executes field deployment of devices and systems, ensures operational readiness, and manages day-to-day grid reliability and service restoration.

5.4 System Control Centre

System Control Centre utilizes grid modernization technologies to monitor system conditions, coordinate switching, and support efficient outage response, ensuring that modernization investments translate into day-to-day operational effectiveness.

This integrated delivery model ensures that the grid modernization plan is scalable, cost-effective, and aligned with organizational capacity and goals. The supporting workforce plans presented in the application reflect the resource requirements needed to maintain this capability through the 2027–2031 period.

6. INVESTMENTS BY DRIVER

Below in Table 4 is a summary of the technologies to be employed, organized by the drivers underpinning those investments.

Table 4: Investments by Driver

Driver	Summary of Investments
Reliability	Grid modernization investments improve system reliability by reducing outage durations and preventing unnecessary service interruptions under normal operating conditions. • SCADA-Enabled Switches enhance reliability by enabling rapid fault isolation and rerouting of power during abnormal grid conditions. These switches help reduce the number of affected customers and minimize outage duration. • CFCIs improve fault location accuracy by identifying fault locations, allowing for faster crew dispatch and accelerated restoration. • Reclosers and Self-Resetting Fuses automatically clear faults and isolate permanent ones, preventing large-scale outages and preserving service to unaffected areas. • Enhanced data analytics platforms provide Elexicon staff with real-time and historical insights to identify reliability risks, optimize grid performance, and support proactive maintenance.
Resiliency	Grid resiliency is strengthened through technologies that enable rapid response and recovery from outages caused by faults or extreme weather events. • SCADA-Enabled Switches enable remote sectionalizing and rerouting of power after an outage has occurred, reducing restoration time and customer impact. • CFCIs provide accurate fault location data during outage events, allowing crews to be dispatched directly to the problem area, improving restoration speed and efficiency. • Reclosers and Self-Resetting Fuses respond to faults automatically, maintaining service to unaffected areas and expediting recovery following disruptive events. • Enhanced data analytics support faster outage response and recovery by helping to identify fault patterns, assess system stress, and prioritize restoration during extreme events.

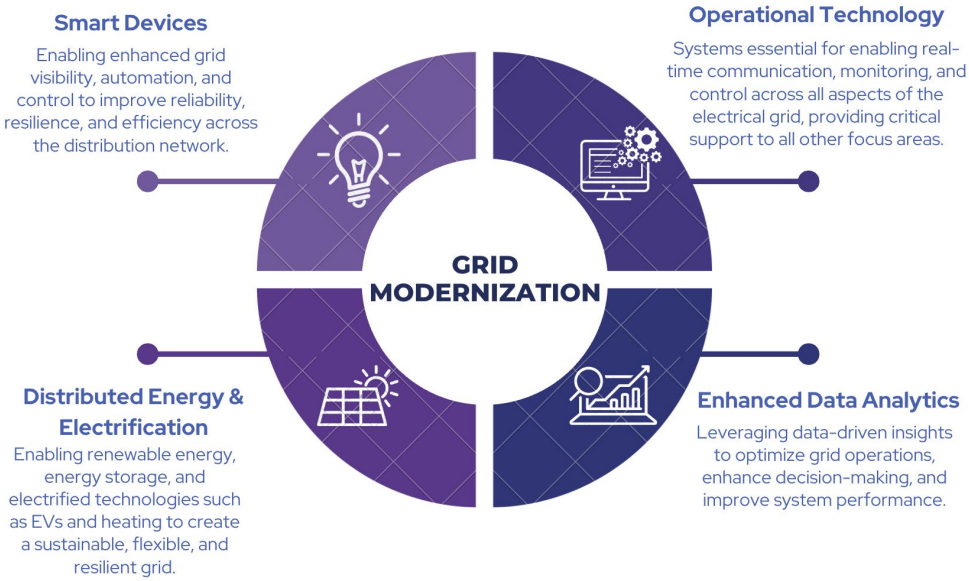
Driver	Summary of Investments
Efficiency	Grid modernization investments improve operational efficiency by reducing the need for manual field activity and enabling more effective use of resources. These improvements support outage response and strengthen long-term cost-effectiveness. • SCADA-enabled switches and self-resetting fuses reduce truck rolls for fault investigation and manual switching by enabling remote isolation and automated fault response. • CFCIs support more efficient field response by providing accurate fault location information, reducing the need for time-consuming patrols and enabling crews to be deployed directly to the affected area. • Enhanced grid visibility through AMI 2.0 and temperature monitoring supports earlier detection of abnormal conditions, reducing the frequency and duration of unplanned maintenance and enabling more proactive asset management.
Load Growth	Elexicon is one of the fastest-growing utilities in Ontario, facing sustained residential, commercial, and industrial development across its service area. This growth is further amplified by increasing electrification, particularly from EVs and electrified heating. Grid modernization investments are required to ensure the system can reliably accommodate rising demand without compromising service performance. • AMI 2.0 enables improved visibility into customer usage and system loading, improving load forecasting and allowing for more responsive load management strategies. • SCADA-Enabled Switches support dynamic grid reconfiguration, enabling efficient load transfers and reducing stress on feeders and substations under pressure from development-driven demand. • Monitoring and control capabilities allow for proactive management of system constraints and ensuring grid capacity is optimized to support continued regional growth and electrification. • Data analytics tools improve load forecasting, identify capacity constraints, and support timely system upgrades to accommodate growing demand.

Driver	Summary of Investments
DER Integration	The proliferation of DERs such as rooftop solar and battery energy storage introduces system variability and complexity, requiring more sophisticated monitoring and control. • AMI 2.0 enhances visibility into bi-directional power flows, fault conditions, and voltage variations, supporting more precise protection coordination. • SCADA-Enabled Switches enable dynamic grid reconfiguration to isolate faults and maintain safe operating conditions in DER-rich environments. • SCADA devices facilitate real-time monitoring and operational adjustments in response to bi-directional power flow.
Safety	Safety enhancements are a core benefit of grid modernization, minimizing field crew exposure and improving situational awareness during outage restoration through automation and monitoring. • SCADA-Enabled Switches reduce the need for manual switching, allowing remote isolation and restoration to avoid live-contact operations. • CFCIs reduce the time spent locating faults, limiting crew exposure during adverse weather or emergency conditions. • Reclosers and Self-Resetting Fuses mitigate sustained outages and limit fault propagation, thereby preventing unnecessary crew dispatch. • AMI 2.0 offers enhanced visibility into abnormal voltage and equipment conditions, enabling earlier detection of anomalies reducing the likelihood of unsafe operating conditions.

7. INVESTMENT FOCUS AREAS

Elexicon Energy is committed to modernizing its electricity distribution system to meet the evolving needs of its customers and communities. This Grid Modernization Plan has four focus areas: Smart Devices, Operational Technology, Distributed Energy & Electrification, and Enhanced Data Analytics. Together, these focus areas provide a roadmap for creating a resilient, automated grid in the near term, and lay the foundation for a longer-term vision of a decentralized grid with increased DER deployment. The following figure outlines the purpose of each of these focus areas, and the path to achievement.

Figure 2: Grid Modernization Focus Areas



7.1 Smart Devices

Elexicon's plan to enhance its distribution network's reliability, resilience, and efficiency involves two key components: a) integrating advanced visibility, and b) automation and control technologies.

As the energy landscape evolves, these capabilities are becoming increasingly vital to meet the growing demands of energy users, enable new technologies, and support a more dynamic grid.

7.1.1 Grid Visibility

Purpose: Obtain the ability to monitor and analyze real-time data from across the distribution network. This includes tracking critical parameters such as fault detection, system performance, power flows, and voltage levels.

Improved visibility allows:

- Reduced operational costs associated with fault finding and isolation.
- Identification of anomalies and potential asset failures proactively, thereby mitigating the likelihood of service disruptions and unplanned outages.

- Improved restoration times of service to customers during power outages.
- Monitoring load distribution and power quality to ensure consistent and reliable energy delivery.
- Identification of grid abnormalities during extreme weather events to prioritize mitigation efforts.
- Improved identification of dangerous conditions like downed power lines quickly to prevent accidents and ensure public safety.
- Minimization of field crew deployments and more efficient switching operations through automation and remote SCADA.

Path to achievement:

In support of enhanced grid visibility, Elexicon plans to deploy key technologies, including AMI 2.0, CFCIs, and Temperature Monitoring, to provide real-time insights into grid performance and operations.

AMI 2.0: Represents the next generation of advanced metering infrastructure, enabling two-way communication between meters and the utility, which improves outage management, enhances load forecasting, and provides customers with accurate, near real-time energy usage data.

CFCIs: Strategically installed to quickly and accurately detect and locate faults within the grid, significantly reducing the time required for fault restoration and improving reliability while ensuring safer operations during emergencies.

Temperature Monitoring: Provides an additional layer of operational intelligence by continuously monitoring conductor temperatures at crucial locations within the electrical grid, allowing for proactive maintenance, reducing the risk of overloaded assets, and extending asset lifespans.

Collectively, these technologies, supported by the enabling operational technology systems, will augment operational efficiency, improve system reliability and resiliency, enhance customer service, and ensure the grid is prepared to meet future demands.

Refer to the Appendices in Exhibit 2B – Tab 4 – Schedule 3 for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

7.1.2 Grid Automation & Control

Purpose: With Grid Automation and Control, Elexicon will be able to act on real-time insights obtained through grid visibility. This includes implementing automated responses, remote operations, rerouting power flows, stabilizing voltage levels, and maintaining seamless operations to ensure reliability and efficiency across the distribution network.

Improved grid automation and control allows:

- Automated fault location, isolation, and service restoration (FLISR).
- Rerouting of power to maintain service during infrastructure damage or outages.
- Address transient faults by momentarily interrupting the system, potentially preventing a sustained interruption and ensuring service continuity for customers.
- Remote operation and fault isolation, reducing the need for manual interventions and minimizing outage durations.
- Support efficient maintenance practices and operational response by limiting the need for field crew deployments to resolve issues.

Path to achievement:

Elexicon plans to deploy key technologies, including SCADA-Enabled Switches and Self-Resetting Fuses at critical points across the system to improve operational efficiency and reliability.

SCADA-Enabled Devices: Enable remote operation and real-time monitoring, allowing operators to quickly isolate faults, reroute power, and reduce outage durations without requiring manual intervention. These switches are strategically placed to enhance system flexibility, improve fault response times, and ensure seamless operations during both planned and unplanned events.

Self-Resetting Fuses: Address transient faults by momentarily interrupting and clearing temporary issues, preventing them from escalating into sustained interruptions. This ensures continuous service for customers, reduces the need for field crews, and minimizes response times.

Together, these technologies, supported by Elexicon's advanced operational technology systems, will strengthen grid performance, enhance reliability and resiliency, and position the utility to meet the evolving demands of modern energy users.

Refer to Appendices in Exhibit 2B – Tab 4 – Schedule 3 for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

7.2 Enhanced Data Analytics

Purpose: By acquiring mature data analytics capabilities, Elexicon will make data-driven decisions that optimize grid operations, enhance system reliability and resiliency, and improve customer experience. By leveraging real-time and historical data, Elexicon will gain actionable insights into grid performance, asset health, and customer energy usage, driving efficiencies across all aspects of the electrical distribution system.

The integration of data analytics is essential for addressing the increasing complexity of modern electrical grids. These tools provide enhanced situational awareness, long-term planning, and facilitate proactive maintenance, minimizing unplanned outages and operational inefficiencies.

Path to achievement:

To support its Data Analytics Initiatives, Elexicon plans to invest in the following technologies:

Improved GIS Mapping: Ensures accurate spatial and asset data, which is critical for fault location, maintenance planning, and efficient dispatching.

Real-Time System Analytics & Engineering Reporting: Provides system operators with real-time insights into grid performance, enabling proactive issue resolution and improved decision-making.

Asset Performance Monitoring System: Tracks the condition and performance of critical grid assets, allowing for predictive maintenance and reduced risk of failures.

Data Historian: Captures and stores historical grid performance data, supporting long-term planning and operational optimization.

AMI 2.0: Enables two-way communication between the utility and smart meters, providing customers with improved visibility into energy usage data and proactive outage notifications.

IVR (Integrated Voice Response) Integration Enablement: Enhances interactive voice response systems to provide customers with accurate and automated updates on service status and account information.

Customer Service Platform Integration Enablement: Streamlines customer interactions by integrating various service platforms, enabling efficient handling of inquiries, complaints, and account management.

Outage Reporting: Provides real-time updates to customers during outages, offering transparency and reducing uncertainty.

Refer to Appendices in Exhibit 2B – Tab 4 – Schedule 3 for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

7.3 Distributed Energy & Electrification

Purpose: The energy landscape is undergoing a profound transformation, driven by the proliferation of electric vehicles (EVs), the trend toward electrified heating, and the adoption of distributed energy resources (DERs) such as solar and battery storage. As technologies become more affordable and accessible, customers are increasingly looking to connect these systems to the grid.

Accommodating bi-directional energy flows from customer-owned systems back to the grid requires a modernized distribution network and enhanced operational capabilities to manage increased complexity associated with bi-directional energy flows, ensuring stability, and optimizing the benefits of these technologies.

To prepare for this transition, Elexicon must proactively invest in proven grid technologies and infrastructure to ensure that the grid is able to safely, reliably and efficiently meet the evolving need of customers.

Path to achievement:

To support this energy transition and enable customers to connect their equipment seamlessly, Elexicon is making strategic investments in the following technologies:

AMI 2.0: Provides improved energy usage data and supports two-way communication between the grid and customer-owned DERs. This technology is essential for managing the bi-directional power flows associated with DERs, ensuring grid stability, and empowering customers to make informed decisions about energy usage.

ADMS: Enables the seamless integration of DERs, EVs, and electrified heating by providing real-time visibility and control across the distribution network. Through advanced functionalities like load forecasting, voltage regulation, and distributed resource management, ADMS dynamically balances supply and demand while mitigating potential grid instabilities caused by fluctuating DER outputs or increased electrification loads.

DSO Enablement: Elexicon is implementing DSO modules integrated with SCADA and DERMS to manage the influx of distributed energy resources. This investment enables real-time monitoring and coordination of DERs, ensuring grid stability while maximizing their utilization.

By preparing the grid for the increased energy demand and bi-directional energy flow, Elexicon will have a future-ready network that empowers customers. These advancements will ensure that Elexicon remains focused on the aspects of grid modernization that will create value for customers.

Refer to Appendices in Exhibit 2B – Tab 4 – Schedule 3 for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

7.4 Operational Technology

Purpose: Operational Technology (OT) is necessary for integration and coordination across all focus areas, including Smart Grid, Customers, Data Analytics, and Distributed Energy & Electrification. OT encompasses the essential systems, software, and infrastructure that facilitate real-time communication, monitoring, and control of the electrical grid. These technologies ensure the full realization of Elexicon's modernization initiative benefits, driving efficiency, reliability, resiliency and security. Through strategic investments in OT, Elexicon is not only enhancing its current operational capabilities but also preparing the grid for future advancements and emerging energy demands.

Path to achievement:

OT System Cybersecurity Hardening: Implementing robust cybersecurity measures to protect grid systems from threats, ensuring operational integrity and data security.

MPLS and APN: Enhancing communication networks to provide secure, high-speed, and reliable data transmission across the grid.

SCADA Communication System Implementation & Renewal: Upgrading SCADA communication systems to ensure real-time monitoring, fault detection, and system control capabilities.

ADMS: Enables the seamless integration of DERs, EVs, and electrified heating by providing real-time visibility and control across the distribution network. Through advanced functionalities like load forecasting, voltage regulation, and distributed resource management, ADMS dynamically balances supply and demand while mitigating potential grid instabilities caused by fluctuating DER outputs or increased electrification loads.

Outage Reporting: Provides real-time updates to customers during outages, offering transparency and reducing uncertainty.

IVR Integration Enablement: Enhances interactive voice response systems to provide customers with accurate and automated updates on service status and account information.

Customer Service Platform Integration Enablement: Streamlines customer interactions by integrating various service platforms, enabling efficient handling of inquiries, complaints, and account management.

SAP Integration Enablement: Links SAP systems with customer platforms to ensure seamless billing, service updates, and account management, improving the overall customer experience.

Database Upgrades, High Availability Enablement, and Maintenance: Improving database infrastructure to ensure data accessibility, reliability, and resilience, supporting critical grid operations.

Middleware Upgrades: Strengthening middleware infrastructure to enable seamless integration and interoperability between various grid management systems.

Custom Software Programs to Enable Business Processes: Developing tailored software solutions to streamline business processes, improve operational workflows, and enhance system functionality.

Mobile Workforce/Switching Order (Real-Time Status): Implementing mobile solutions to optimize field operations, enabling real-time updates and improving responsiveness.

OT System Upgrades: Upgrading existing systems to ensure cybersecurity, maintain vendor and regulatory compliance, and improve scalability, reliability, resiliency and overall performance. This also includes implementing custom features and enhancements to optimize workflows and drive operational efficiency.

OT systems provide the foundation for real-time monitoring, advanced automation, and seamless integration of diverse technologies, enabling the grid to operate effectively under increasing demands and complexities. These investments enhance system resilience, streamline operations, and support customer-centric initiatives, ensuring that Elexicon meets its commitment to delivering high-quality service. By prioritizing Operational Technology, Elexicon is ensuring the robustness of its grid infrastructure, maintaining service reliability, and supporting the evolving needs of the system.

Refer to Appendices in Exhibit 2B – Tab 4 – Schedule 3 for details on each technology/investment, proposed for deployment in the 2027 to 2031 period.

8. CONCLUSION

Elexicon's Grid Modernization Plan establishes a clear and coordinated pathway for transforming the distribution system to support reliability, resiliency, flexibility, and the capability to meet future energy needs. The plan responds directly to the key drivers identified in this report, including rising customer expectations, increasing electrification, growing DER adoption, and the need for improved operational visibility and control.

Over the 2027 to 2031 period, Elexicon plans to invest more than $59M in capital to advance this plan. Through these investments in proven field technologies, enhanced operational technology systems, and integrated data and customer platforms, Elexicon is enabling a modernized grid that can adapt to evolving demands.

The phased approach outlined in this plan ensures that modernization efforts are sequenced effectively, beginning with foundational investments that strengthen visibility, automation, and system intelligence, and progressing toward more advanced capabilities that will support higher levels of reliability, resiliency, DER integration, and customer participation. These efforts are supported by a cross-functional organizational model that aligns the expertise of Asset Management, Digital and Innovation, System Control Centre and Operations to plan, implement, and sustain modernization initiatives over time.

As technologies mature, system conditions change, and customer and regulatory expectations evolve, Elexicon will continue to review and refine its modernization activities to ensure alignment with long-term strategic objectives. By advancing this plan, Elexicon is positioning its distribution system to remain reliable, adaptable, and customer focused, ensuring it can meet the needs of the communities it serves both now and into the future.

EXHIBIT 2B - TAB 3 - SCHEDULE 2: APPENDIX B
ELEXICON ENERGY ACA FINAL REPORT

Elexicon Energy

2025 Asset Condition Assessment Report

BBA Document No. / Rev.: 7884003-40-ERA-0001 / FR
Client Document No.: 0001
October 21st, 2025

Final Report

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LIST OF ACRONYMS AND DEFINTIONS

ACA -	Asset Condition Assessment
AM -	Asset Management
BBA -	BBA Inc.
DAI -	Data Availability Index
DGA -	Dissolved Gas Analysis
Elexicon -	Elexicon Energy Inc.
GPR	Ground Potential Rise
HFCT -	High Frequency Current Transformer
HI -	Health Index
HIF -	HI Formulation
LDC -	Local Distribution Company
IR -	Infrared Scan
OESC -	Ontario Electrical Safety Code
OH -	Overhead
OQ -	Oil Quality
PD -	Partial Discharge
PF -	Power Factor
SAMP -	Strategic Asset Management Plan
SLG -	Single Line to Ground
TDR -	Time Domain Reflectometry
TUL -	Typical Useful Life
TX -	Transformer
UG -	Underground
VLF -	Very Low Frequency

Executive Summary

This report relays the findings of an Asset Condition Assessment ("ACA") of the major electrical and select civil assets of Elexicon Energy Inc. ("Elexicon" or "the utility") – a licensed electricity distributor operating in the former Whitby Hydro and Veridian Connections service areas. Aside from relaying the results of the quantitative assessment of the available asset demographics and condition data, the report also discusses the role of the ACA in the utility Asset Management ("AM") frameworks and specifically in the context of mergers and acquisitions. The report concludes with a series of recommendations related to the incremental enhancement of Elexicon's data collection practices and recommends several potential AM metrics that the utility may wish to implement to track the progress of its enhancements in the AM space and derive new operating and strategic insights.

Context of the Study

Elexicon engaged BBA Inc. ("BBA") to conduct an ACA study. Elexicon aims to further refine the merged company's AM strategy and approaches to asset lifecycle management. To assist Elexicon in this work, this report includes an expanded discussion on the role that ACA results play in the modern evidence-based AM frameworks and provides a series of recommendations aimed at the establishment of a comprehensive and sustainable AM practice over time.

Elexicon has taken steps to consolidate the data collection and analysis practices across its service territory, enabling it to undertake consistent asset health analysis in current and future ACA iterations. The inspection and maintenance program are combined, and the data included in this report reflects that of a merged utility.

Being a relatively new phenomenon in Ontario's electricity distribution sector, quantitative ACA studies such as this report continue encountering material data availability gaps, both in terms of availability of specific types of information commonly expected in asset HI formulations ("HIFs") and availability of data across the entire asset base. This report is not an exception to this relatively common – but generally improving – data availability trend. In the instances where data gaps within a given asset class did not enable us to calculate asset HIs for the entire population, BBA identified these assets as having an "Unknown HI" in the respective sections presenting the results of our assessment.

In most cases, the above classification signals the fact that a given asset does not currently have the requisite number of recorded HI parameters to meet the data availability threshold commonly employed in the industry. Overall, we note that the scope of available asset data employed in our study (and by extension, the comprehensiveness of its results) has increased since the last iteration. While room for continuous improvement remains, we note the progress relative to the prior studies is material and deserves commendation.

Scope of the Study

The study covers twenty-two distribution and station asset classes, which represents all the essential equipment directly involved in the delivery of Elexicon's electricity distribution service.

- **Distribution assets:**
  - Wood Poles;
  - Concrete Poles;
  - UG ("Underground") Cables;
  - Submarine Cables;
  - OH ("Overhead") Conductors;
  - Pole-mounted Transformers;
  - Pad-mounted Transformers;
  - Vault Transformers;
  - Step Transformers;
  - Submersible Transformers;
  - Pad-mounted Distribution Switchgear; and
  - OH Switches.
- **Station assets:**
  - Station Power Transformers;
  - Station Circuit Breakers and Pad-mounted Reclosers;
  - Station Switches;
  - DC Backup Battery Supply (including Station batteries and Chargers);
  - Station Protection Relays;
  - Station Cables;
  - Station Switchgears;
  - Station Buildings;
  - Station Fences; and
  - Station Switchgears.

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health, containing five categories – from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, given as a score from 0 to 100. The HIFs for individual asset classes represent weighted averages of numerical scores for individual HI subcomponents, known as condition parameters, scored on a scale from 0 to 100. The numerical score ranges, condition categories, and typical characteristics of an asset are described in Table 1.

Table 1: Definition of HI Scores

Score (%)	Condition Category	Description
85-100	Very Good	Some evidence of aging or minor deterioration of a limited number of components
70-85	Good	Significant deterioration of select components to be managed through normal maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components
30-50	Poor	Widespread serious deterioration across multiple components
0-30	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life

Elexicon's 2025 System HI Distribution is shown in Figure 1 and are also described in more detail in Section 4.

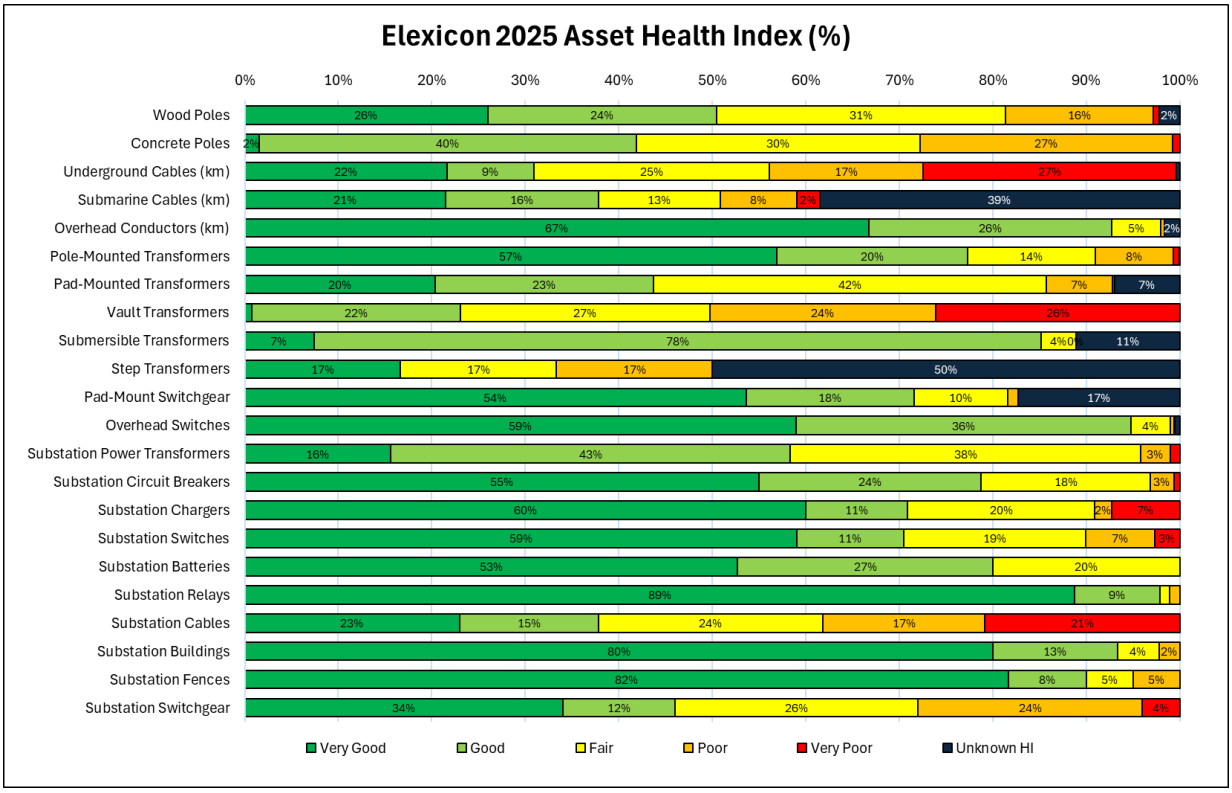


Figure 1: System-wide Asset Condition Assessment Results

As the above figures indicate, the vast majority of Elexicon's assets are in Fair condition or better based on our assessment, with relative contributions of Poor, and relatively minor contributions of Very Poor not indicative of extensive deterioration across the system or any concerns with the manner in which assets have been managed in the past.

Unknown HI contribution is relatively minor over the entire system. Asset classes with Unknown HI scores correspond to the individual units where the number of available data inputs falls below the required threshold – below which the HI cannot be reliably calculated. Data quality and availability for the ACA have improved over time. The asset classes affected by data availability issues fall into three groups that contextualize the observed data availability:

1. Equipment that relied on an exception-based approach to asset inspections, recording condition data only for the assets with significant degradation issues;

2. Asset classes where condition data is logistically complex or uneconomic to collect (e.g., overhead conductors where condition tests typically involve the use of expensive equipment and are typically reserved for transmission equipment only);

3. Asset classes that Elexicon intends to phase out from operation (e.g., concrete poles that are being replaced with wood poles as the existing units reach their end-of-life, except for the cases where customers specifically request and pay for a concrete pole).

Elexicon's Current Health Index Maturity and Continuous Improvement

In several cases, Elexicon's current asset data records contain less than three condition parameters for each asset class – a numerical threshold that qualifies an asset health score to be formally viewed as an Asset HI. In these cases, we labelled the results of our analysis as two-parameter assessments but presented the results across all asset classes in a consistent format. Overall, we found Elexicon to have a material amount of data that enabled us to conduct analysis that should yield meaningful managerial insights to the utility's planners.

With respect to the core distribution utility assets like station power transformers, we were able to construct relatively advanced multi-factor health indices. While comparatively less information is available for some other asset classes, the lack of availability or data diversity relative to other distributors' practices need not be automatically equated to a gap or an oversight on the part of the utility. As with other operating dimensions, utility decisions regarding the scope of data collection represent strategic trade-offs in the environment of multiple priorities and constrained operating costs.

As we note at the outset of this study, Elexicon is relatively early into its existence as a merged entity, with the long-term approach to AM data collection, and use in decision-making remaining under development. Given this organizational reality, BBA fully expects Elexicon to consolidate its asset condition collection and analysis activities to determine which additional parameters (if any) it will collect going forward. We expect that Elexicon will continue to make these determinations based on the recommendations contained in this report, balancing the continuous improvement considerations with the opportunity cost of other activities it will be required to undertake in the course of its operational and strategic consolidation.

1. Introduction

BBA Inc. ("BBA") previously developed a health index ("HI") framework for Elexicon Energy Inc.'s ("Elexicon" or "the utility") fixed electrical distribution and substation assets in 2024. Since then, Elexicon's asset data quality continues to improve, with increased age demographics and inspection/test results available. This allows for continuous improvement of Elexicon's asset health demographics in a manner consistent with international Asset Management ("AM") standards. Elexicon engaged BBA to update the Asset Condition Assessment ("ACA") of Elexicon's fixed electrical distribution and substation assets to improve the accuracy of system health demographics based on the latest 2024/2025 asset registry, testing, inspection data.

For this report, BBA relied on the following data sources:

- Asset inspection and testing data collected by Elexicon staff or external contractors;
- Additional reports for certain asset classes compiled by Elexicon employees;
- Discussions with Elexicon's engineering and asset management ("AM") staff;
- Past deliverables pertaining to specific undertakings prepared by staff or consultancies.

BBA employed an objective threshold-based approach related to the percentage of assets for which data was available to determine whether a given parameter would be included in the Health Index ("HI") calculation as per the broadly accepted methodology. As such and by way of foreshadowing our recommendations to management, BBA recommends that Elexicon's integrated AM function concentrate its efforts on ensuring that the data already being collected for some assets is captured for all the assets in the system rather than investing in new types of asset information. To assist Elexicon with further asset data efforts, Section 6 of this report contains a number of recommendations identifying specific types of data to be collected for the asset classes examined.

In recognition of Elexicon's current efforts to define its future AM strategy, this report also provides a set of recommendations for advanced AM metrics that the utility can choose to deploy to derive additional managerial insights from the data collected in the field. We provide our recommendations solely for the purposes of helping the utility consider the range of approaches to advancing its AM capabilities and expect that Elexicon will exercise its discretion as to their suitability based on careful consideration of their value proposition relative to the opportunity cost of other strategic initiatives.

2. Asset Condition Assessments as Inputs into Broader Asset Management Planning

2.1. Evidence-Based Asset Management for Distribution Utilities

At its core, the discipline of AM helps organizations derive optimal economic value from their existing and contemplated capital investments in a financially sound and responsible manner. Like modern organizations in other asset-intensive sectors, electric utilities face numerous pressures and opportunities to invest their invariably scarce resources into projects that generate the greatest amount of value for their shareholders and customers. While several potential reference points exist that an organization can choose as a benchmark for structuring its AM processes, there is a general consensus in the electricity transmission and distribution sector that the methodology most suitable for the sector's needs is articulated in the ISO 5500x group of standards (which includes Standards 55000, 55001 and 55002). The core purpose of these standards is the establishment, utilization, and continuous enhancement of AM systems.

An AM System is a group of activities that integrate the collection of asset information and its application to asset planning and investment decision-making process. AM Systems enable utilities to prolong the operating lives and good performance of their assets in a manner that optimizes both short-term and long-term costs while maximizing other objectives valued by the organization and its key stakeholders including safety, environment, reputation, affordability, and others. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM System;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous Improvement stage - those looking to assess and progressively enhance an AM System already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organization can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.

Since it involves the allocation of inherently scarce resources, modern utility AM is about making informed and explicit trade-offs, supported by data that objectively evaluates the necessity and urgency of a given investment – be it in and of itself, relative to other investments, or no investment taking place at all. Key sources of supporting data for an electric utility can take many forms, and typically include:

- Information on the current state of the assets across the service territory:
    - Physical condition of equipment (e.g., wear/tear, natural degradation, etc.);

- Equipment demographic data (age, manufacturer, material, location); and
- Manner and extent of equipment's utilization (e.g., average loading vs. top capacity).

- Data on the likelihood of events that an investment seeks to prevent, or bring about:
  - Information on past failure occurrences (how, when, where);
  - Results of statistical analysis of the underlying causes of failures (why); and
  - Past trends of actualized demand growth and known future development plans.
- Data on impact (value gains or losses) of events that investments seek to prevent or facilitate:
  - Cost of potential repairs if an asset fails unexpectedly;
  - Costs sustained by customers due to loss of supply;
  - Safety costs of potential injuries to employees and public, or environmental costs; and
  - Presence of redundancies and other capabilities to mitigate any negative impact.

2.1.1. Key Analytical Inputs into Asset Management Systems and Strategies

An effective AM System entails a constant feedback loop, where results of operations are analyzed against the original planning assumptions and past results, enabling adjustments to strategy and analytical tools. This feedback loop provides organizations with inputs for the development of near-term, and longer-term AM Plans, Policies, or Strategies. These formal (and usually ever-green) documents articulate the manner in which a utility will utilize its AM Systems to achieve its AM objectives, such as liquidation of known equipment deficiencies, compliance with new requirements, improvement of performance levels, integration of new load, and many others. As Figure 2 illustrates, AM Systems, Plans, and Strategies must balance multiple forms of Inputs (performance data, stakeholder preferences, etc.) and Constraints (funding availability, regulatory requirements, etc.) to achieve their stated objectives.

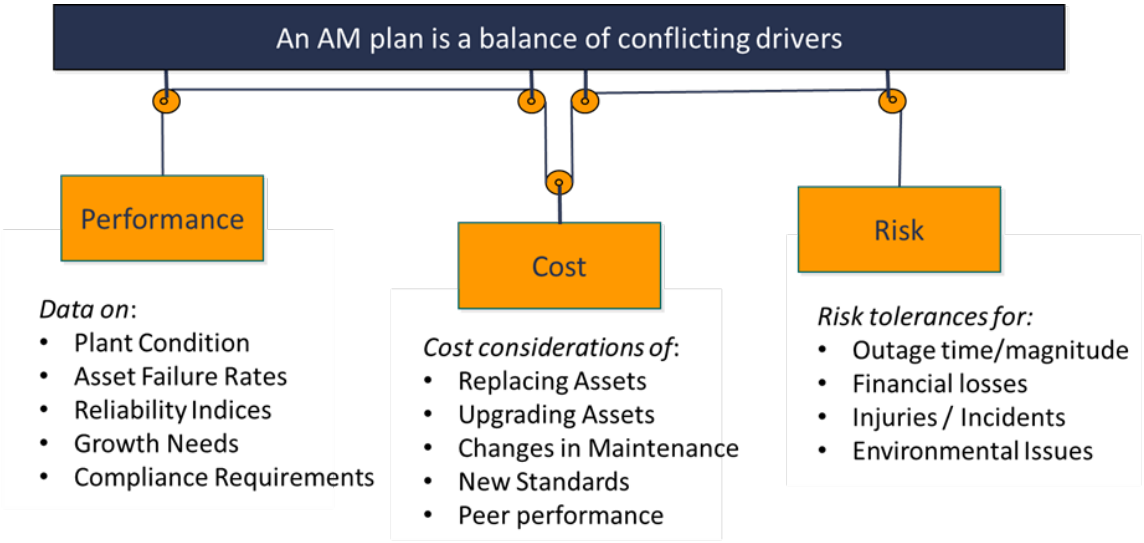


Figure 2: Key AM Plan Inputs and Considerations

While most of these inputs, drivers, and constraints have existed for as long as utilities have been in business, the way in which utilities articulate, analyze, and reconcile these factors is undergoing significant changes in line with the continued development of engineering and economic science. The knowledge and experience of utility subject matter experts continue to play an important role in the development of AM plans. However, technology is changing the customer and regulator expectations as to how (the inevitably subjective) judgment of experts can be supported by objective assessment and prediction of the likelihood, impact, and cost of events that AM plans seek to prevent or bring about.

As can be gleaned from the above discussion of information sources and constraints, an organization's decision to conduct an ACA position it to collect and leverage the information consistent with the first of the three major types of AM decision-making inputs categorized in section 3.1. An ACA is often the first step in establishing (or executing – if already established) a utility's broader AM System – an overall organizational approach to making decisions associated with the continued extraction of value from the assets at its disposal to achieve its core objectives. Underlying any AM System are transparent and evidence-based tools and principles that seek to maximize the expected value of investments over their lifetimes.

2.1.2. Asset Condition Assessments as Long-Term Value Drivers

An ACA is most often thought of as a snapshot in time of the health of a utility's asset base, and by extension, the inputs into planning for addressing its short-term and medium-term intervention needs. Yet, when utilized to its fullest potential, an ACA can yield several other useful insights to asset planners, including:

- The degree to which the current pace of asset interventions (i.e., maintenance, replacement, refurbishment activities) is contributing (positively or negatively) to the overall scope and magnitude of risks managed by the organization;
- The anticipated pace of asset degradation in the future and the ensuing opportunities for making intelligent trade-offs (i.e., by accepting the risks of further degradation on some assets or parts of the system while proactively intervening in others);
- The relationship between the observed/calculated asset degradation parameters and the assets' propensity for failure or mis-operation in a manner that the organization deems to be unacceptable (i.e., by tracking and constructing condition-based failure curves);
- The cost-benefit trade-offs of any potential changes to the mix of capital vs maintenance work that a utility may wish to implement to manage its total expenditures, (e.g., deploying labour-minimizing online sensor technology while reducing manual testing);
- The approximate magnitude of capital expenditures that the utility may need to plan to undertake over the longer-term (i.e., when the ACA results are presented in the form of financial metrics, such as replacement cost-weighted condition grade distribution);
- The magnitude of operating expenses and the sequencing/prioritization of ensuing activities to enhance the utility's overall AM framework, as gleaned from the identified asset Data Availability Index ("DAI") and/or other recommendations; and
- The scope and functionalities of advanced AM Information or Operational Technology investments are contemplated as a part of strategic discussions towards the digitization of utility operations.

The above list of potential insights is neither exhaustive nor wholly applicable to Elexicon's current state of operations or its strategic priorities. Instead, we present this list as an important reminder that utilities should see the ACA documents as organizational assets in and of themselves – insofar as they represent monetary investments to obtain an objective reading of the state of an organization's core assets. Beyond explicitly informing asset intervention plans, ACAs can act as critical objective inputs into a range of decisions that inherently involve value-based judgment on the part of decision-makers.

3. Asset Health Index Calculation Methodology

ACA is the process of determining an HI, which is a quantitative expression of an asset's current condition. It was first published in a 2006 IEEE article[1] and has since been adopted across various best-practice documents[2,3]. A brand-new asset should have an HI of 100% and an asset in very poor health should have an HI below 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2 presents the HI ranges and the corresponding asset condition.

Table 2: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
30-50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

3.1. Condition Parameters

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific to each asset class. A condition parameter can be comprised of many sub-condition parameters. For example, the oil quality ("OQ") condition parameter of an asset belonging to the station power transformer class includes multiple sub-condition parameters such as acid number, interfacial tension, dielectric strength, and water content.

To determine the overall HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that particular asset type. A weight is assigned to each condition parameter to indicate the amount

[1] T. Hjartarson and S. Otal, "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level," in *IEEE 11th Int. Conf. on Transmission & Distribution Construction, Operation and Live-Line Maintenance*, Oct. 2006.
[2] D. Thompson, T. Hjartarson, K. Martin-Sturmey, B. Lau, "Development of a Health and Risk Index Tool for a Station," CEATI International Inc., Report No. T143700-3097, Montreal, QC, Canada.
[3] T. Hjartarson, S. Otal, R. Jain, "Distribution System Health Indices," CEATI International Inc., Report No. T134700-6018, Montreal, QC, Canada.

of influence the condition has on the overall health of the asset. Figure 3 provides an example of an HIF table.

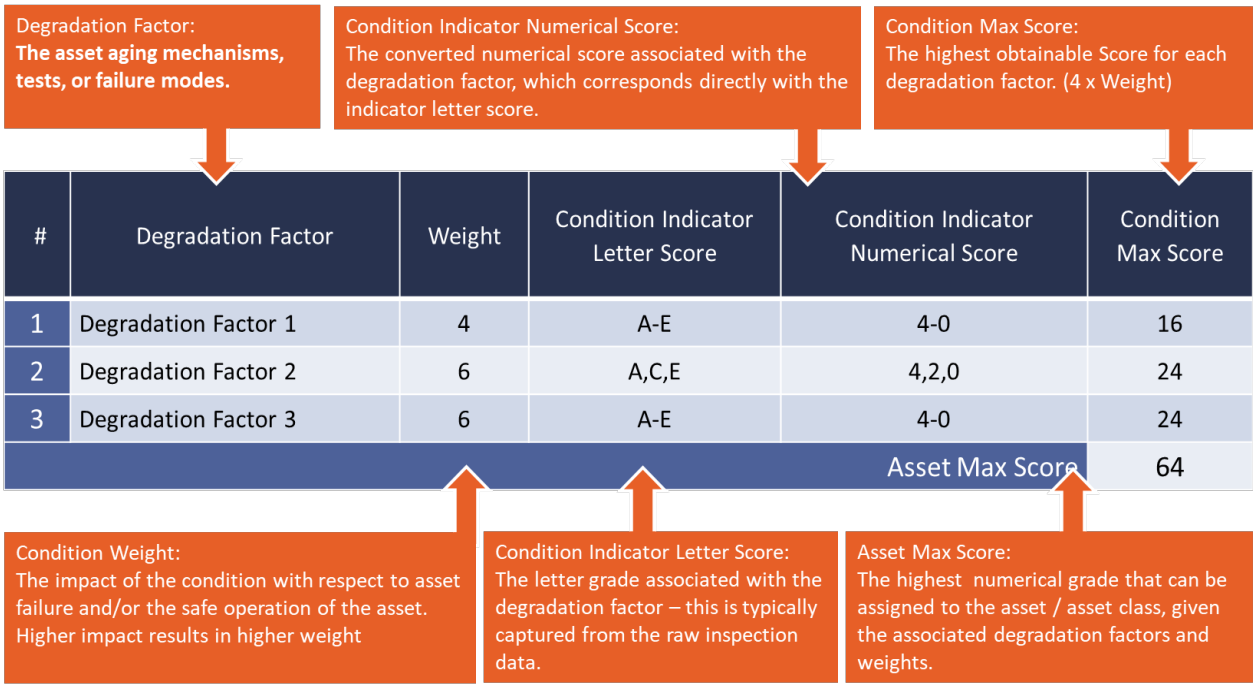


Figure 3: HI Formulation Components

The scale used to determine an asset's score for a condition parameter is called the Condition Indicator. Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Condition Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade. In some cases where there are multiple sub-condition parameters contributing to a single condition parameter, the lowest sub-Condition Indicator is taken as the overall Condition Indicator for that parameter. This prevents deficiencies in an asset's health from being covered up by averaging processes during the HI calculation.

The conversion from alphabetic ranking to numerical grade and a brief character description of the grade is provided in Table 3.

Table 3: Sample Letter - Numerical Conversion Chart

Letter/Number Grade	Grade Description
A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

3.1.1. Final Asset Health Index Formulation

The final HI, which is a function of the Condition Indicators and weights, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} W_i * CI_i}{CI_{max.}}\right) \times 100\%$$

where:

- i corresponds to the condition parameter number within the HIF;
- CI_i represents the Condition Indicator as determined from the testing or field-inspection procedure that is associated with condition parameter i;
- W_i represents the relative importance of condition parameter i within the HI based on the impact of the parameter on the asset's overall failure probability;
- CI_{max} represents the highest numerical grade that can be assigned to the asset and is being used to normalize the final HI score between 0 and 100; and
- HI represents the asset health index as a percentage.

3.1.2. Asset Health Index Results

An asset's HI is given as a percentage; the HI is calculated only if sufficient condition parameter data for a given asset is available. The subset of the total population with sufficient data parameters is called the sample size. HI results can be analyzed on a per-asset, per-asset-class, or per-system basis depending on the granularity required in the analysis.

3.2. Data Sources

To assess the condition of Elexicon's stations and distribution systems, BBA was provided with available asset inspection and maintenance data for the asset classes in scope. The data provided included asset registries, visual inspection records, and testing records. Most of this data came from primary sources such as equipment inspection forms completed by Elexicon staff or by third parties. In addition to the data provided by Elexicon, BBA conducted station inspections.

3.2.1. Data Enhancements

BBA and Elexicon worked closely together to address gaps in their data availability found in their 2024 Asset Condition Assessment. BBA worked with Elexicon's planning & execution teams to collect more data, such that accurate HI results are maximized across Elexicon's population of assets. The scope these data enhancements are summarized in the points below.

- In-Field Inspections: To account for missing in-field inspection data, BBA worked directly with Elexicon to establish in-field inspection plans and collect missing data. ACA results were updated with new inspection data for Elexicon's overhead assets, which include wood poles, concrete poles, and overhead switches.
- Age Extrapolation: BBA extrapolated age data for select distribution asset classes which included wood poles, concrete poles, UG cables, OH conductors, pole-mount transformers, pad-mount transformers, vault transformers, pad-mount switchgears, and overhead switches. For each asset class, BBA grouped similar assets based on GIS coordinates provided by Elexicon. For assets missing age data, service age was estimated using the average age of its adjacent assets. This methodology assumes that adjacent assets are similar in age.
- New Asset Classes: Step transformers and station switchgears were added as a new distribution asset and station asset class respectively.
- Identifying Gaps from Current-State ACA Results: BBA worked directly with Elexicon to analyze current-state gaps within the 2023 and 2024 ACA results. This included gaps in asset age and missing in-field inspection data, missing substation assets, and IR data.

3.2.2. Data Availability Index

The Data Availability Index ("DAI") is a measure of the availability of condition parameter data for a specific asset, as they pertain to the construction of the HI score. The DAI is determined by comparing the sum of the weights of the condition parameters available to the total weight of the condition parameters used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} W_i * \alpha_i}{\sum_{i=1} W_i}\right) \times 100\%$$

where:

- i iterates through the condition parameters within the HIF;
- Wi is the weight assigned to condition parameter i;
- α_i represents the data availability coefficient, which is equal to 1 if data is available, and equal to 0 when data is unavailable; and
- DAI represents the Data Availability Index as a percentage.

An asset with all condition parameter data available will have a DAI value of 100% independent of the asset's HI score. Assets with a higher DAI will correlate to HI scores with a higher degree of confidence.

3.2.3. Data Gaps

The HIFs calculated in this study are based only on available data provided by Elexicon. In almost all instances, additional condition parameters or tests exist that can be performed on an asset to further ascertain its state of degradation. In certain cases, condition parameters may be available for one or several assets in a class, but unavailable for others in the same class. This scenario represents a data gap, wherein the planner must determine whether the number of assets for which a particular parameter is available is sufficient to include it in the calculation of the overall HI.

An asset with all condition parameter data available will have a DAI value of 100%, independent of that asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For all asset classes, the DAI threshold is 60%. Where missing data are assumed to be infrequent and random, the HI may be extrapolated across the asset category, and in other cases, the data may be flagged for collection.

3.3. Use of Age as a Condition Parameter

There is a degree of debate within the electrical utility industry regarding the appropriateness of including age as a condition parameter for calculating asset Health Indices. At the core of the argument against the use of age in assessing asset condition is the notion that age implies a linear degradation path for an asset that does not always match the experience in the field. While some assets lose their structural integrity faster than would be expected with time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, BBA attempts to limit the instances where it relies on age as a parameter explicitly incorporated into the calculation of asset HI. In some cases, however, the limited number of condition parameters available for the calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing the condition of complex equipment (e.g., power transformers) – which contain a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing – age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the context of the current study, the availability of data on condition parameters varied significantly across asset classes. Where BBA deemed the number of available condition parameters as insufficient to calculate a reliable HI for a particular asset class, and especially where the available information amounted to factors that do not represent the most significant degradation factors for a particular type of equipment, we included age as one of the condition parameters where nameplate data was available.

4. Asset Condition Assessment Results

This section presents the current HIF for each asset class, the calculated HI scores, and the data available to perform the study. For most of the assets, an HI was already developed based on industry best practices and then modified based on a reasonable expectation of data availability. In the case of overhead conductors, only demographic information is given because condition data is not available. In other cases, the only data available is demographic (age) data taken from the asset registry along with the results of visual field inspections.

Table 4 and Figure 4 present the results of our ACA study in numerical and graphical formats, respectively.

Table 4: Summary Results

Asset Class	Population	Health Index Distribution (%)						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Wood Poles	34874	26%	24%	31%	16%	1%	2%	96%
Concrete Poles	2379	2%	40%	30%	27%	1%	0%	100%
Underground Cables (km)	2624	22%	9%	25%	17%	27%	0%	98%
Submarine Cables (km)	26	21%	16%	13%	8%	2%	39%	65%
Overhead Conductors (km)	4696	67%	26%	5%	0%	0%	2%	99%
Pole-Mounted Transformers	8831	57%	20%	14%	8%	1%	0%	100%
Pad-Mounted Transformers	14770	20%	23%	42%	7%	0%	7%	96%
Vault Transformers	655	1%	22%	27%	24%	26%	0%	100%
Submersible Transformers	27	7%	78%	4%	0%	0%	11%	91%
Step Transformers	6	17%	0%	17%	17%	0%	50%	50%
Pad-Mounted Switchgear	457	54%	18%	10%	1%	0%	17%	81%
Overhead Switch	16844	59%	36%	4%	0%	0%	1%	85%
Station Power Transformer	96	16%	43%	38%	3%	1%	0%	96%
Station Circuit Breaker	160	55%	24%	18%	3%	1%	0%	99%
Station Charger	55	60%	11%	20%	2%	7%	0%	100%
Station Switch	149	59%	11%	19%	7%	3%	0%	85%
Station Battery	55	53%	27%	20%	0%	0%	0%	96%
Station Relay	187	89%	9%	1%	1%	0%	0%	92%
Station Cable	283	23%	15%	24%	17%	21%	0%	88%
Station Building	45	80%	13%	4%	2%	0%	0%	99%
Station Fence	60	82%	8%	5%	5%	0%	0%	100%
Station Switchgear	50	34%	12%	26%	24%	4%	0%	98%

Note 1: Minor differences to be expected between ACA population count and other data sources due to data scrubbing and assumptions process.

Note 2: Totals may not add up to 100% due to rounding.

Note 3: Values less than 2% have been removed from Figure 4 for clarity.

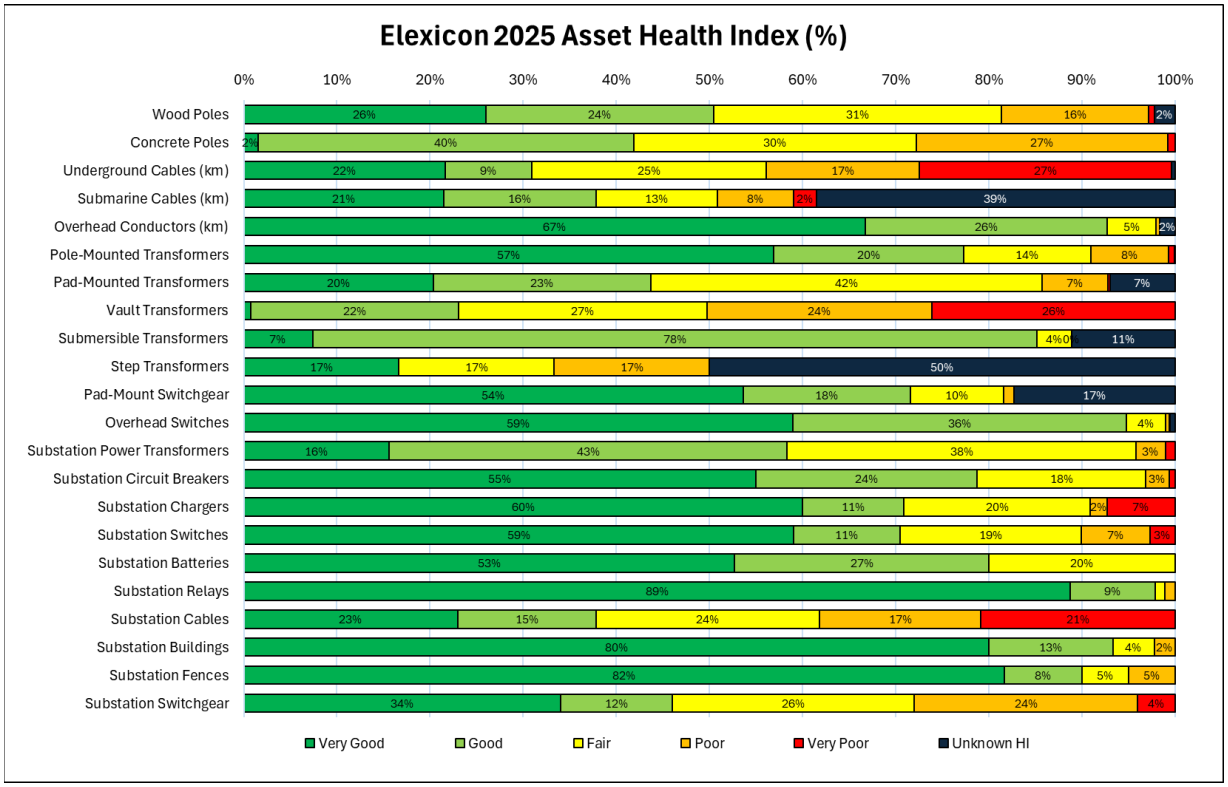


Figure 4: HI Summary Results

As the above results indicate, the vast majority of Elexicon's assets are in a Fair condition or better, with relatively minor portions of assets receiving Poor or Very Poor grades. As such, the results are indicative of a relatively healthy system – with no signs of material deterioration consistent with poor AM practices. The number of assets with an Unknown HI has decreased since previous revisions of the report due to the data enhancements initiative which collected additional data for poles and overhead switches and extrapolated missing ages for most distribution asset classes.

It should be noted that a few asset classes were under former inspection strategies by one or both legacy entities – most notably an exception-based approach to asset inspection, where specific condition information was only recorded for a given unit if the inspector deemed the observed deterioration to be indicative of a need for intervention prior to the next scheduled inspection cycle. While such an approach is typical for a number of Ontario distributors' legacy AM practices, it limits a utility's ability to plan for replacement volumes over the medium term and beyond; its distinct advantage is relative cost-effectiveness.

In some cases, such as for overhead conductors, the collection of empirical condition data involves expensive laboratory or field-testing techniques, which are commonly seen as uneconomic for distribution assets (relative to their high-voltage transmission counterparts). Yet in

other cases, such as with concrete poles, the utility is in the process of phasing out this asset class, replacing them with wood poles as the concrete structures reach end-of-life. Accordingly, while material data gaps exist across a number of asset classes, in many cases these gaps signal a deliberate strategic choice where collecting condition information was deemed to be impractical or uneconomic. In such cases assumptions were used to address data gaps. These assumptions were discussed and verified with Elexicon.

Being a relatively new entity, Elexicon is still in the process of defining its long-term AM strategy. As it continues evaluating its options for a unified approach, we expect it to revisit the scope and nature of data collection practices across its asset classes using the recommendations contained in the remainder of this report.

4.1. Distribution Assets

4.1.1. Wood Poles

4.1.1.1. Condition Assessment Methodology

Wood poles are the most common asset owned by an electrical utility and are an integral part of the distribution system. Poles are the support structure for overhead distribution lines as well as assets such as overhead transformers, switches, and reclosers.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility.

In the short term (one to three years), the most informative end-of-life criterion is the calculation of remaining strength through pole testing. However, since pole strength tends to fall off quickly as a pole starts to degrade, the preferred predictor over the medium to long term (three to ten years) is age. Generally, poles that are newer than ten years in service are not tested at all other than by way of visual inspections. A pole that is not yet showing effects of age but exhibits other defects such as large cracks or rot or is out of plumb may also be targeted for replacement. An example of a wood pole is shown below.



Figure 5: Image of a Wood Pole

The HI for wood poles is calculated based on end-of-life criteria summarized in Table 5. Appendix A.1 provides grading tables for each condition parameter.

Table 5: Wood Pole HIF

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Defects/Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Wood Rot	1	A,B,C,D,E	4,3,2,1,0	4
Remaining Strength	5	A,B,C,D,E	4,3,2,1,0	20
Out of Plumb	1	A,E	4,0	4
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Total Score				52

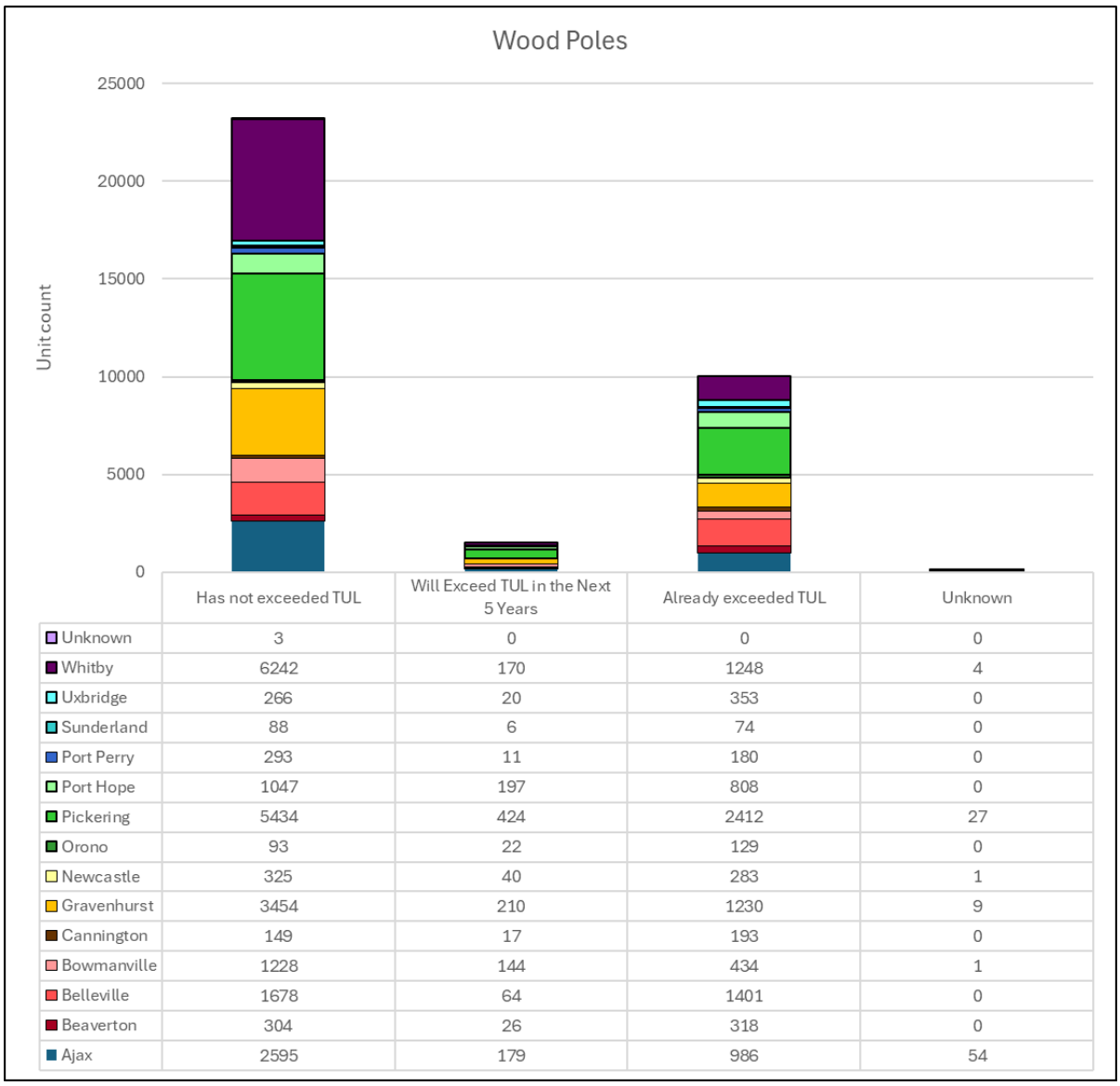
4.1.1.2. Data Collection and Assumptions

Strength testing is not conducted for poles with less than or equal to 10 years of age. For poles within this age range, if no information was available, the remaining strength is assumed to be 100 percent. Similarly, for poles within this age range, if no information was given for defects/overall condition and wood rot it was assumed there were no noted issues and were given a grade of 'A' in their respective data fields.

Service age data was available for 99% of wood poles. If age data for a particular asset, it was estimated based on the average age of its adjacent assets. The average DAI for wood poles across Elexicon's distribution system is 96%.

4.1.1.3. Demographics

Elexicon owns 34,874 wood poles within its service territory. Figure 6 presents the age distribution for in-service wood poles. The typical useful life (TUL) for wood poles is 45 years.

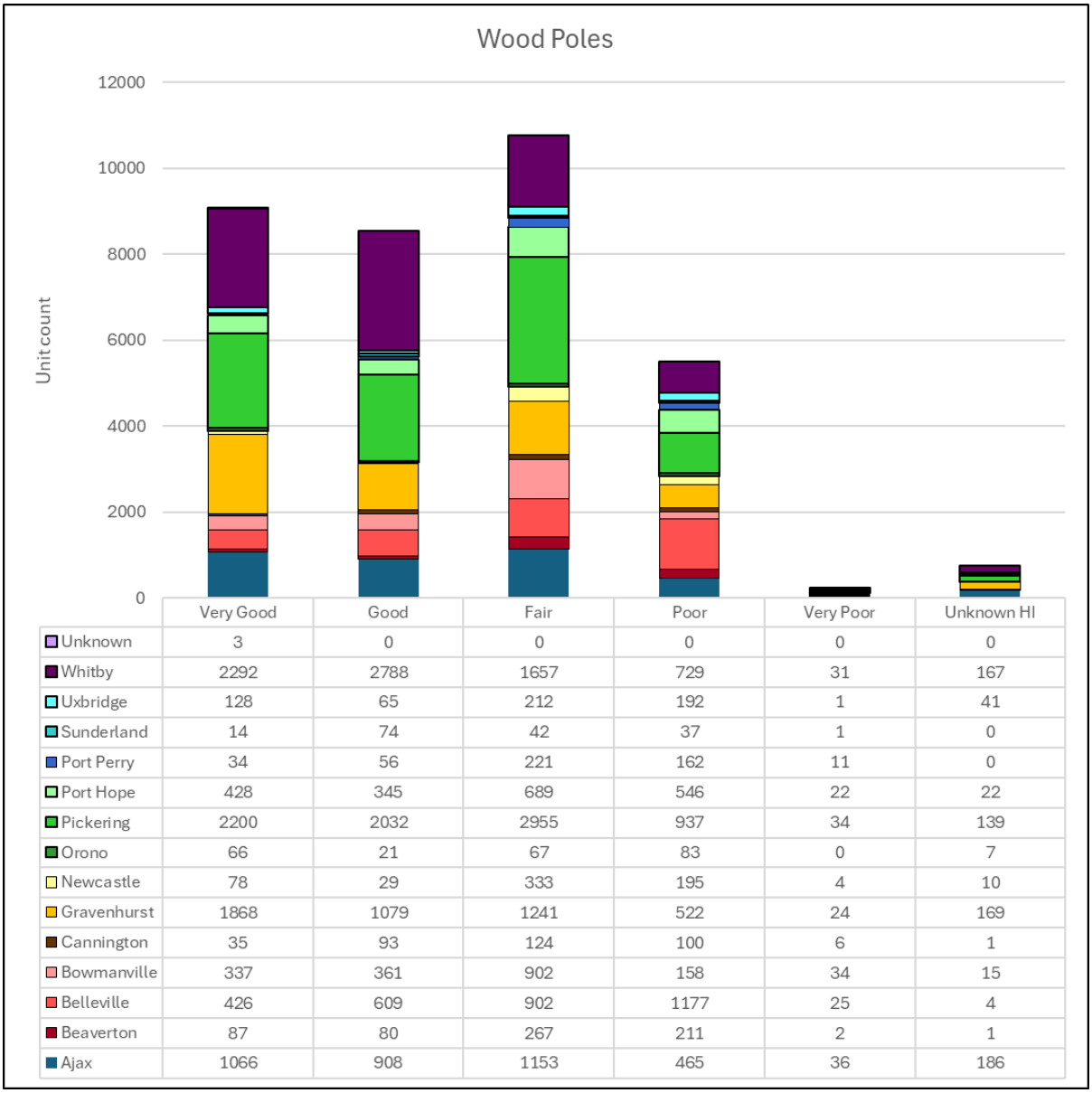


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	3	0	0	0
Whitby	6242	170	1248	4
Uxbridge	266	20	353	0
Sunderland	88	6	74	0
Port Perry	293	11	180	0
Port Hope	1047	197	808	0
Pickering	5434	424	2412	27
Orono	93	22	129	0
Newcastle	325	40	283	1
Gravenhurst	3454	210	1230	9
Cannington	149	17	193	0
Bowmanville	1228	144	434	1
Belleville	1678	64	1401	0
Beaverton	304	26	318	0
Ajax	2595	179	986	54

Figure 6: Wood Pole Age Distribution

4.1.1.4. HI Results

The HI distribution for wood poles is shown for both the entire population and each municipality in Figure 7. Most of Elexicon's wood poles are in Very Good to Fair condition. There are 5745 wood poles in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	3	0	0	0	0	0
Whitby	2292	2788	1657	729	31	167
Uxbridge	128	65	212	192	1	41
Sunderland	14	74	42	37	1	0
Port Perry	34	56	221	162	11	0
Port Hope	428	345	689	546	22	22
Pickering	2200	2032	2955	937	34	139
Orono	66	21	67	83	0	7
Newcastle	78	29	333	195	4	10
Gravenhurst	1868	1079	1241	522	24	169
Cannington	35	93	124	100	6	1
Bowmanville	337	361	902	158	34	15
Belleville	426	609	902	1177	25	4
Beaverton	87	80	267	211	2	1
Ajax	1066	908	1153	465	36	186

Figure 7: Wood Pole HI Results

4.1.2. Concrete Poles

4.1.2.1. Condition Assessment Methodology

Concrete poles have a similar use as wood poles in the distribution system with the exception that concrete poles are often used for specific applications such as downtown core areas, or improved appearance applications. Elexicon has decided that when a concrete pole reaches end-of-life, it is replaced with a wood pole unless financial support is received.

Concrete poles have a different degradation mechanism than wood poles. There is no practical "pole test" for concrete poles, but since poles are hollow, there are also limited opportunities for invisible degradation and interior rot. Concrete poles develop corrosion on the internal reinforcing bars, which expands the iron and displaces the concrete in a process known as spalling. Once spalling begins, poles become weaker and tend to fail over a short number of years. There are limited methods for the long-term repair of a spalled pole. Spalling is accelerated in the presence of road salt. In the short term (one to three years) the most informative indicator is a visual observation of spalling; there is no way to predict that corrosion is occurring inside concrete poles. The best predictor of a need for medium-term replacement (three to ten years) is the age and condition of similar poles. An example of a concrete pole is shown below.



Figure 8: Image of a Concrete Pole

Table 6 below provides the concrete pole HI algorithm. For this asset class, service age was used as a one-parameter assessment. There was not enough inspection data available to incorporate visual condition into the HIF. Additional details about the condition parameter and grading can be found in Appendix A.2.

Table 6: Concrete Pole HIF

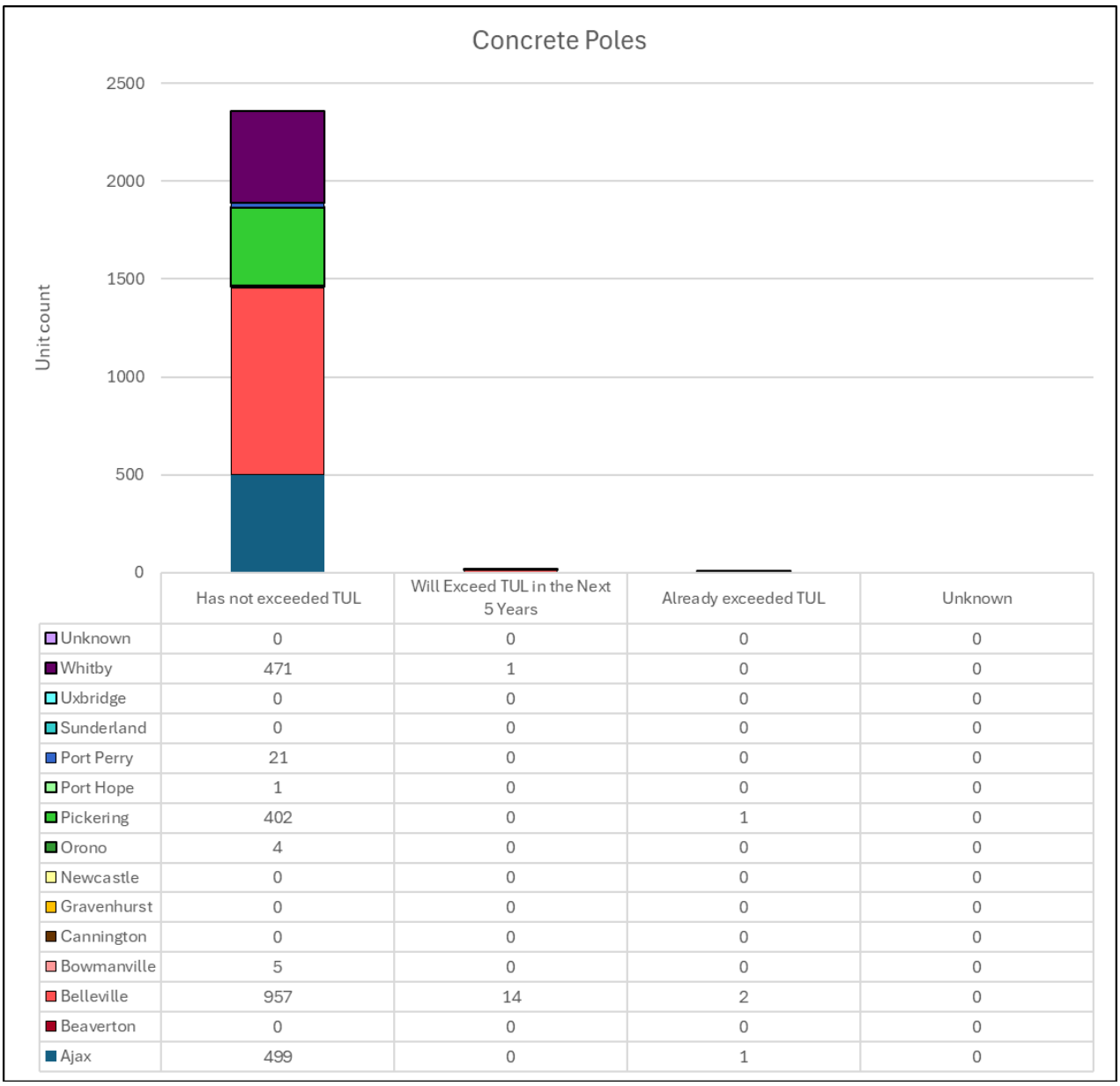
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				12

4.1.2.2. Data Collection and Assumptions

Age data is available for 100% of Elexicon's concrete poles. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. The average DAI for concrete poles is 100%.

4.1.2.3. Demographics

Elexicon owns 2,379 concrete poles. Figure 9 presents the age distribution for concrete poles. The TUL for concrete poles if 60 years.

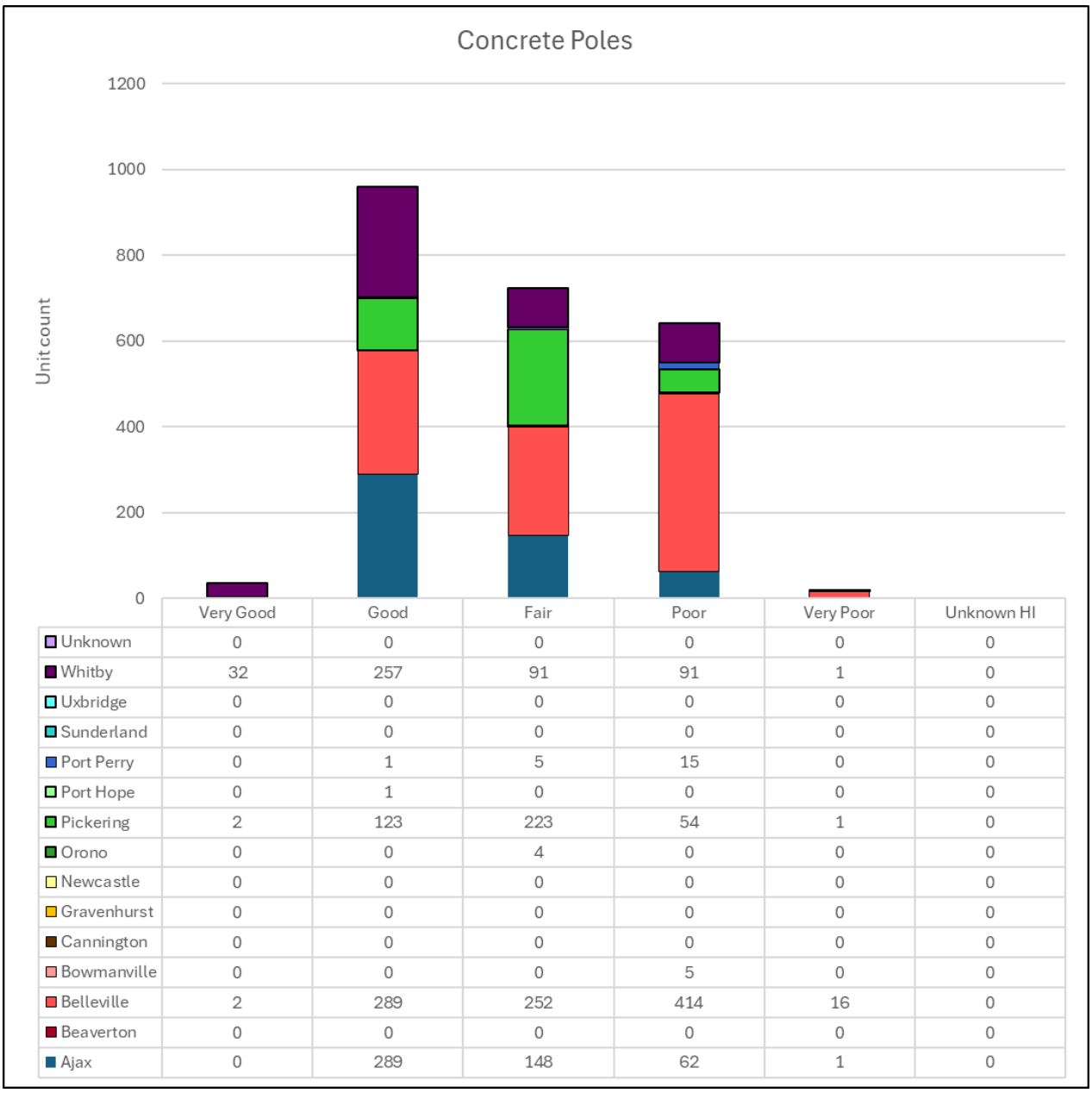


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	471	1	0	0
Uxbridge	0	0	0	0
Sunderland	0	0	0	0
Port Perry	21	0	0	0
Port Hope	1	0	0	0
Pickering	402	0	1	0
Orono	4	0	0	0
Newcastle	0	0	0	0
Gravenhurst	0	0	0	0
Cannington	0	0	0	0
Bowmanville	5	0	0	0
Belleville	957	14	2	0
Beaverton	0	0	0	0
Ajax	499	0	1	0

Figure 9: Concrete Pole Age Distribution

4.1.2.4. HI Results

The HI distribution for concrete poles is shown in Figure 10, most of the poles are in Good to Poor condition. There are 660 concrete poles in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	32	257	91	91	1	0
Uxbridge	0	0	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	1	5	15	0	0
Port Hope	0	1	0	0	0	0
Pickering	2	123	223	54	1	0
Orono	0	0	4	0	0	0
Newcastle	0	0	0	0	0	0
Gravenhurst	0	0	0	0	0	0
Cannington	0	0	0	0	0	0
Bowmanville	0	0	0	5	0	0
Belleville	2	289	252	414	16	0
Beaverton	0	0	0	0	0	0
Ajax	0	289	148	62	1	0

Figure 10: Concrete Pole HI Results

4.1.3. Underground Cables

4.1.3.1. Condition Assessment Methodology

Distribution UG primary cables are one of the more challenging assets on electricity systems from a condition assessment and AM viewpoint. Although a number of test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances will allow the comparison of a given cable segment to other cables of similar vintage. Those sections that have already experienced a fault are also identifiable and are considered a higher risk for recurrence although the data on this topic requires further research. Given the level of detailed information available on the number of splices on UG cable segments, the number of splices is also considered a parameter to assess the condition of a given cable section.

Elexicon has initiated a cable injection program for a group of aged cable sections. For cable sections that are known to have received such treatment, the HI is modified to reflect the life extension. Elexicon has also been running a cable testing program to assess the condition of the cable insulation. As more cable testing results become available, the HI algorithm should be updated to consider these testing results. An example of UG cables is shown in below.



Figure 11: Image of Underground Cables

Table 7 below provides the HI algorithm for UG cables. Additional details about these condition parameters and their manner of grading can be found in Appendix A.3.

Table 7: Underground Cable HIF

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Number of Splices	3	A,C,E	4,2,0	12
Total Score				44

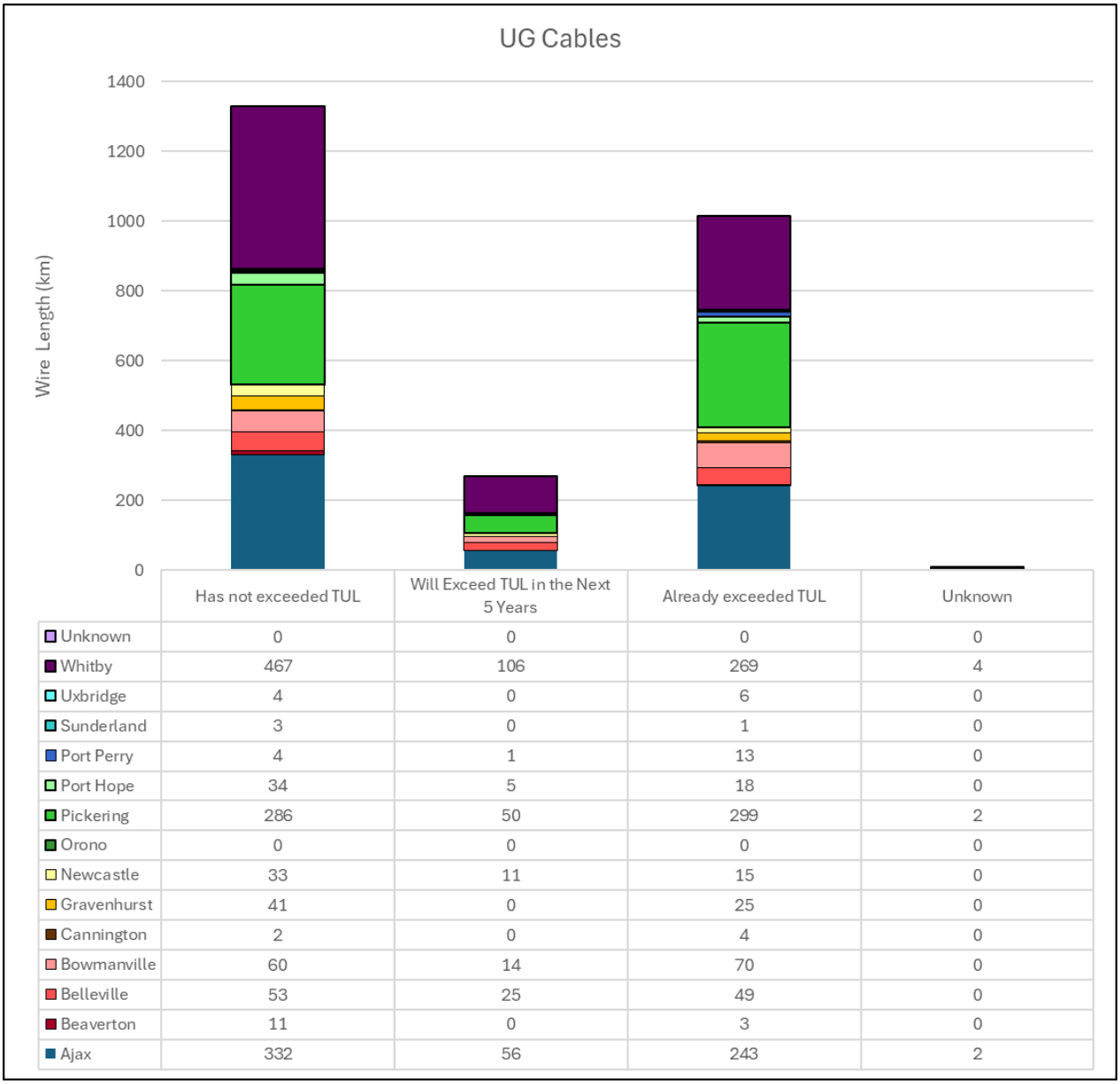
4.1.3.2. Data Collection and Assumptions

Data for this asset is limited to records of age and splice locations as taken from the GIS and asset registry. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets.

Within Elexicon's asset base, around 103 km of UG cables have been injected with a product that is designed to extend cable life. For this study, cable injection is noted, and a life extension of 20 years is considered during HI assessment. This assumption was based on claim from Novinium that its cable injection program can extended life by an additional 20 to 40 years. This assumption was also discussed and verified with Elexicon. The average DAI for the UG cables is 98%.

4.1.3.3. Demographics

The Elexicon system features UG primary cables with a combined length of approximately 2,624 km. Figure 12 shows the overall age distribution by length. Depending on the construction type and insulation material, the TUL for UG cables can be between 25 to 40 years.

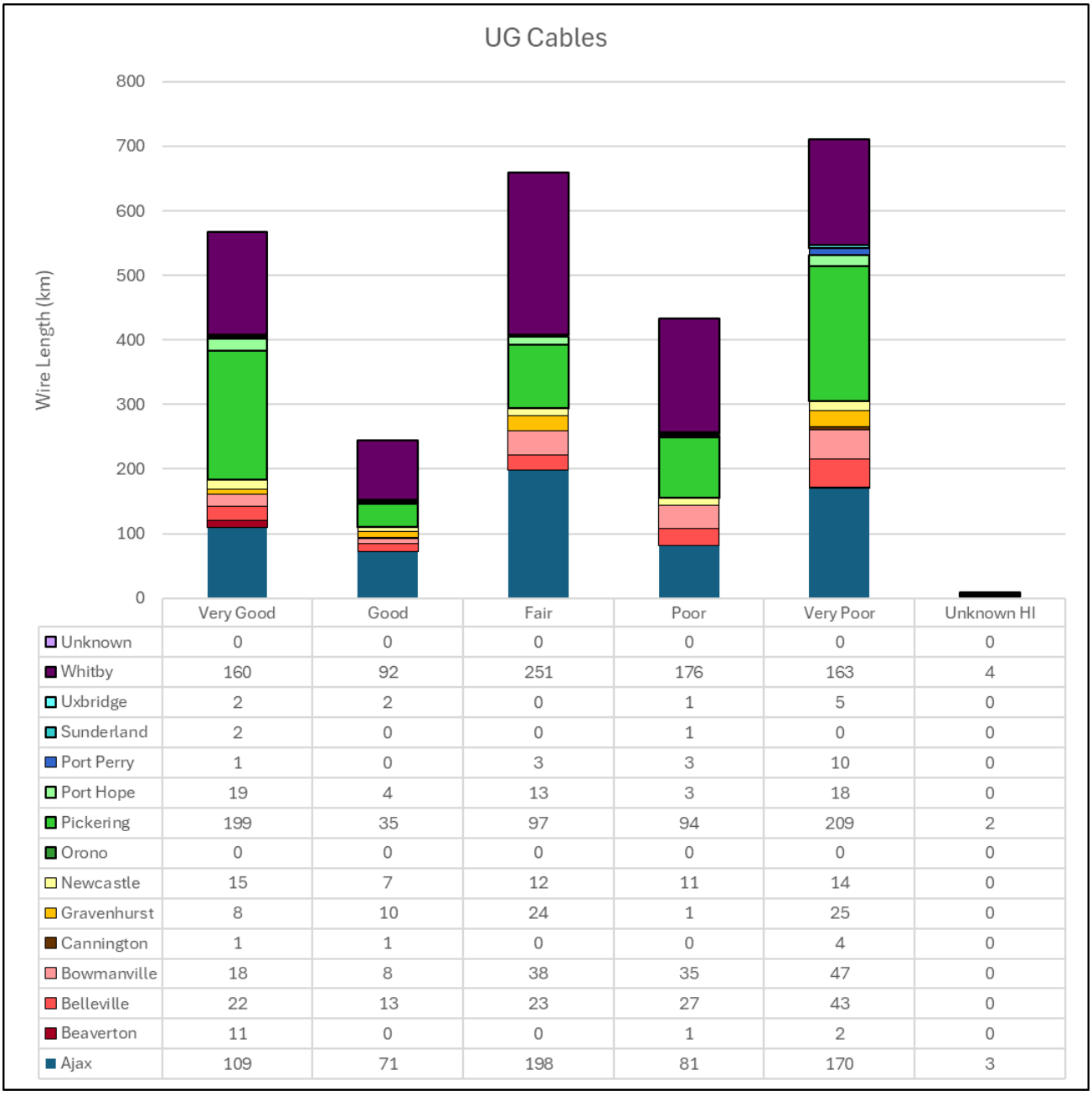


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	467	106	269	4
Uxbridge	4	0	6	0
Sunderland	3	0	1	0
Port Perry	4	1	13	0
Port Hope	34	5	18	0
Pickering	286	50	299	2
Orono	0	0	0	0
Newcastle	33	11	15	0
Gravenhurst	41	0	25	0
Cannington	2	0	4	0
Bowmanville	60	14	70	0
Belleville	53	25	49	0
Beaverton	11	0	3	0
Ajax	332	56	243	2

Figure 12: Underground Cable Age Distribution

4.1.3.4. HI Results

The overall HI distribution for UG cable is presented in Figure 13. Most assets are in Very Good, Fair, or Very Poor condition. Approximately 1143 km of UG cables are in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	160	92	251	176	163	4
Uxbridge	2	2	0	1	5	0
Sunderland	2	0	0	1	0	0
Port Perry	1	0	3	3	10	0
Port Hope	19	4	13	3	18	0
Pickering	199	35	97	94	209	2
Orono	0	0	0	0	0	0
Newcastle	15	7	12	11	14	0
Gravenhurst	8	10	24	1	25	0
Cannington	1	1	0	0	4	0
Bowmanville	18	8	38	35	47	0
Belleville	22	13	23	27	43	0
Beaverton	11	0	0	1	2	0
Ajax	109	71	198	81	170	3

Figure 13: Underground Cable HI Results

4.1.4. Submarine Cables

4.1.4.1. Condition Assessment Methodology

Distribution submarine cables are one of the more challenging assets on electricity systems from a condition assessment and AM viewpoint. Although a number of test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for submarine cables. The standard approach to managing cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement. The asset health results for primary submarine primary cable in this study are calculated by including service age as a major component.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances will allow the comparison of a given cable segment to other cables of similar vintage. Additional metrics include the condition of concentric neutrals, the condition of the cable's armor/sheath/jacket, and a visual assessment of the cable's terminations.

Table 8 below provides the HI algorithm for submarine cables. Additional details about these condition parameters and their manner of grading can be found in Appendix A.4.

Table 8: Submarine Cable HIF

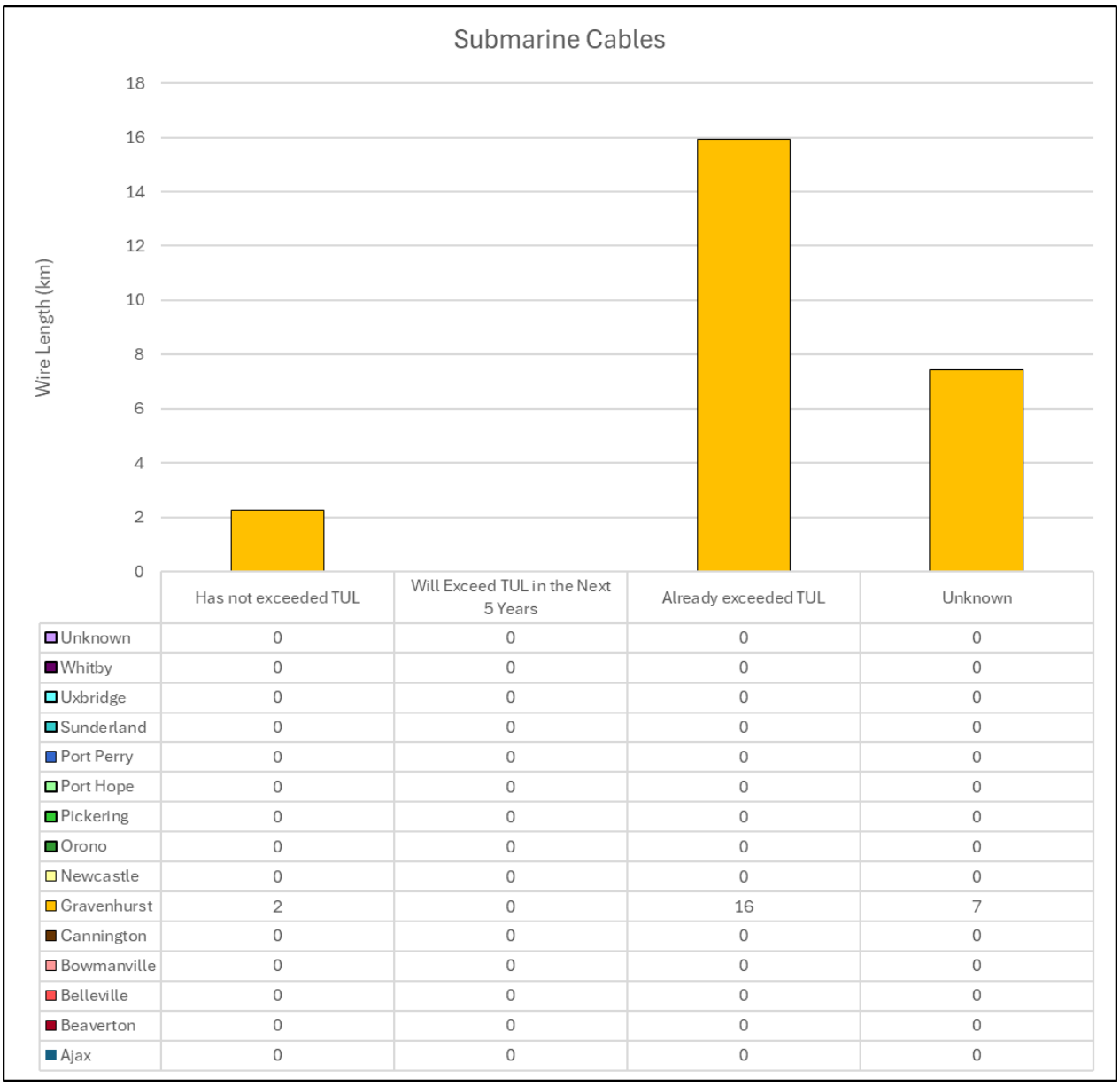
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Concentric Neutral	6	A,B,C,D,E	4,3,2,1,0	24
Condition of Armor/Sheath/Jacket	6	A,B,C,D,E	4,3,2,1,0	24
Visual Inspection of Terminations	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				68

4.1.4.2. Data Collection and Assumptions

Given their below-grade location and the associated access difficulties, information on the condition of submarine cables is notoriously difficult and costly to obtain. The average DAI for the submarine cables is 65%.

4.1.4.3. Demographics

The Elexicon system features submarine cables with a total length of approximately 26 km. Figure 14 shows the overall age distribution of by length.

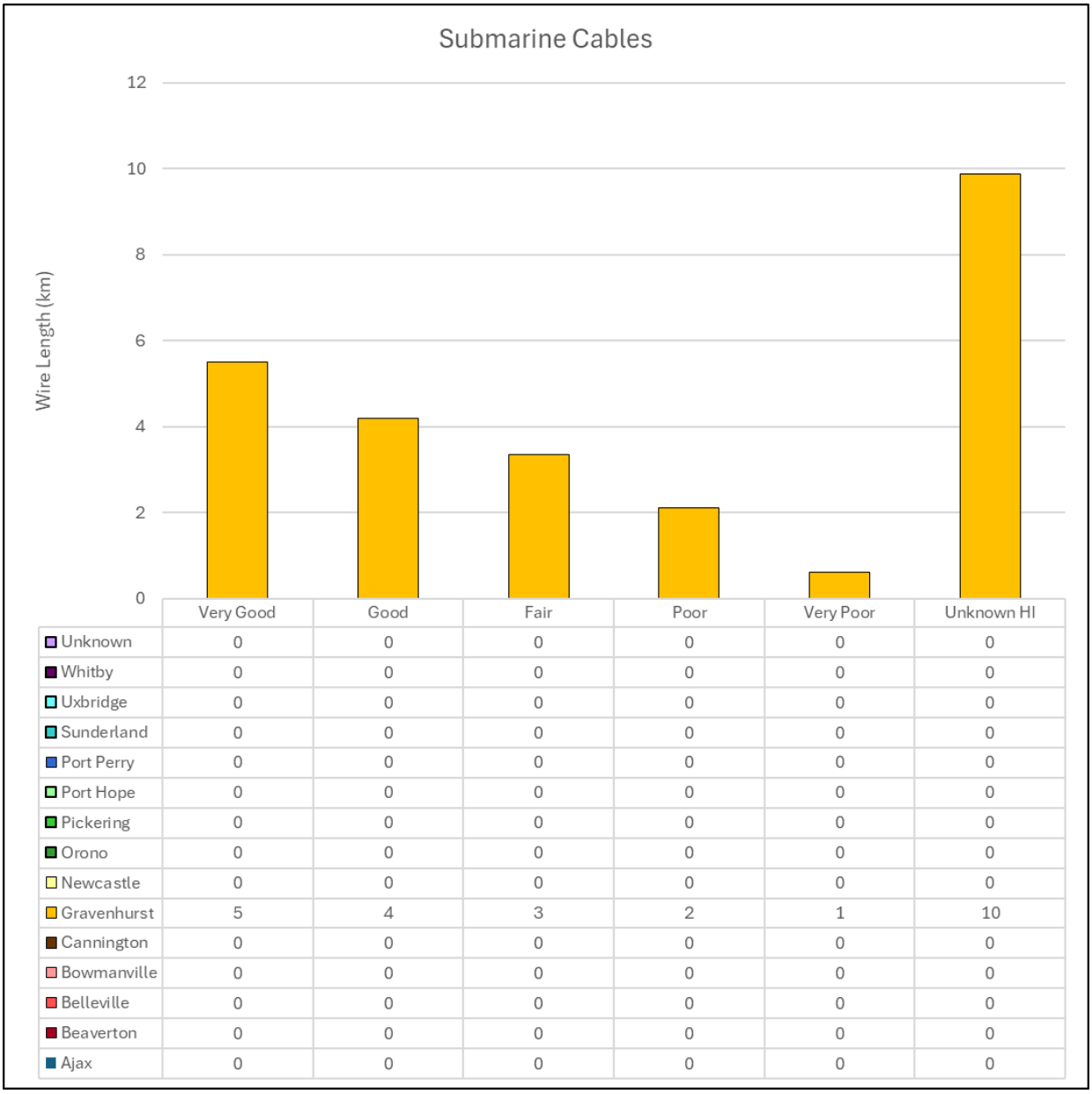


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	0	0	0	0
Uxbridge	0	0	0	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	0	0	0	0
Pickering	0	0	0	0
Orono	0	0	0	0
Newcastle	0	0	0	0
Gravenhurst	2	0	16	7
Cannington	0	0	0	0
Bowmanville	0	0	0	0
Belleville	0	0	0	0
Beaverton	0	0	0	0
Ajax	0	0	0	0

Figure 14: Submarine Cable Age Distribution

4.1.4.4. HI Results

The HI distribution for submarine cable is presented in Figure 15. Due to the low DAI most, submarine cables have Unknown HI. Approximately 3 km of submarine cables are in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	0	0	0	0	0	0
Uxbridge	0	0	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	0	0	0	0	0	0
Pickering	0	0	0	0	0	0
Orono	0	0	0	0	0	0
Newcastle	0	0	0	0	0	0
Gravenhurst	5	4	3	2	1	10
Cannington	0	0	0	0	0	0
Bowmanville	0	0	0	0	0	0
Belleville	0	0	0	0	0	0
Beaverton	0	0	0	0	0	0
Ajax	0	0	0	0	0	0

Figure 15: Submarine Cable HI Results

4.1.5. Overhead Conductors

4.1.5.1. Condition Assessment Methodology

OH conductors are an important component of an overhead system; however, there is almost no inspection or maintenance undertaken. Conductor assets tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. It is very rare that the conductor condition would drive a distinct replacement investment program. There is one recognized conductor risk, namely the tendency for small copper conductors to age at an accelerated rate and become brittle.

Although laboratory tests exist to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for estimating the tensile strength of conductors and estimating the remaining life of an asset is the use of service age. An example of OH conductors is shown below.



Figure 16: Image of Overhead Conductors

Table 9 below provides the HI algorithm for the OH conductor. Additional details about these condition parameters and their manner of grading can be found in Appendix A.5.

Table 9: Overhead Conductor HIF

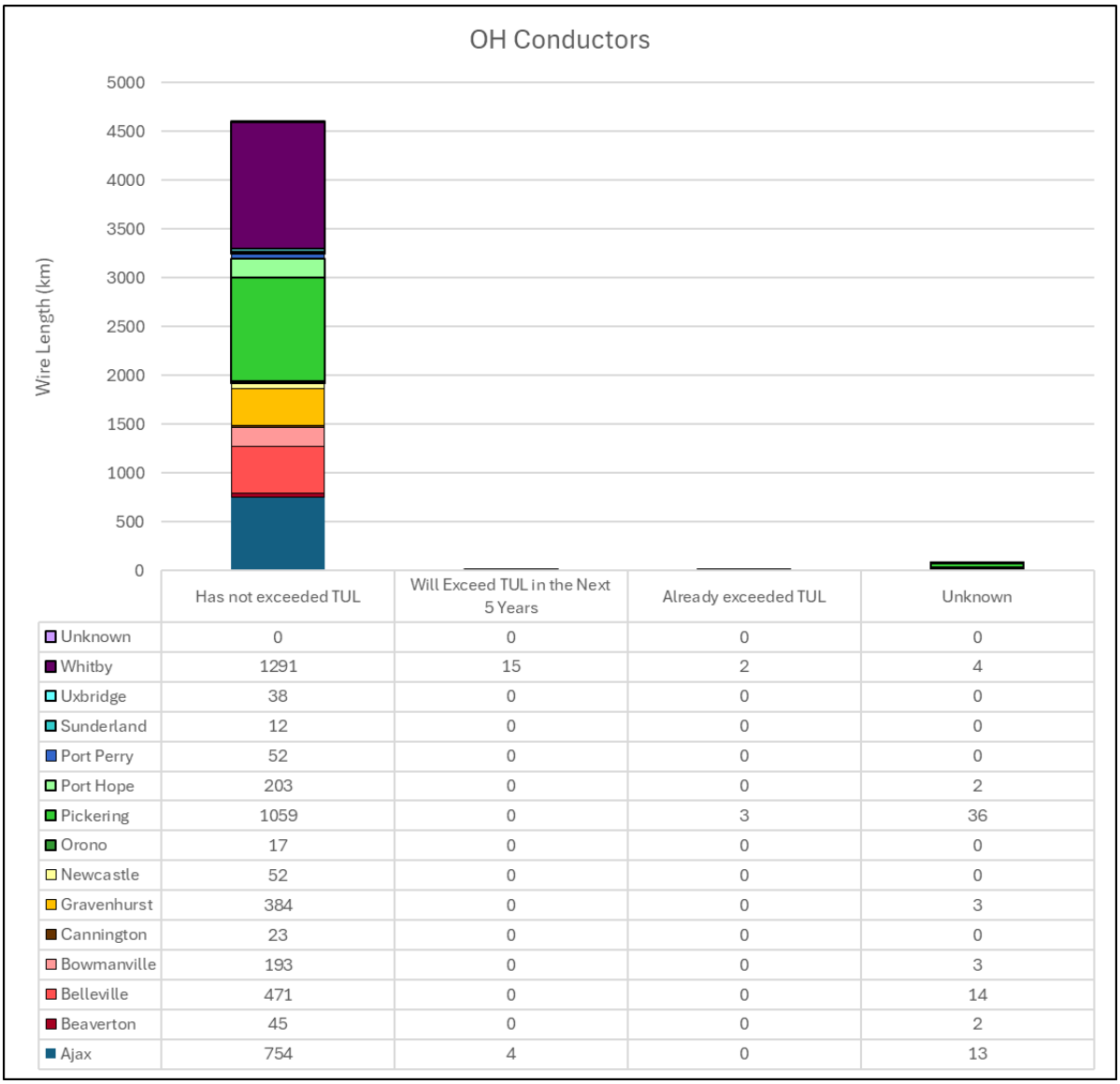
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Small Conductor Risk	1	A,E	4, 0	4
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				12

4.1.5.2. Data Collection and Assumptions

Service age is available for 99% of OH conductors. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. Conductor size is available for 100% of OH conductors. Conductor sizes that were marked unknown were assumed to be non-small copper conductors. The average DAI for OH conductors is 99%.

4.1.5.3. Demographics

Elexicon manages approximately 4,696 km of overhead conductors. Figure 17 presents the age distribution of OH conductors. The TUL for OH conductors is 60 years.

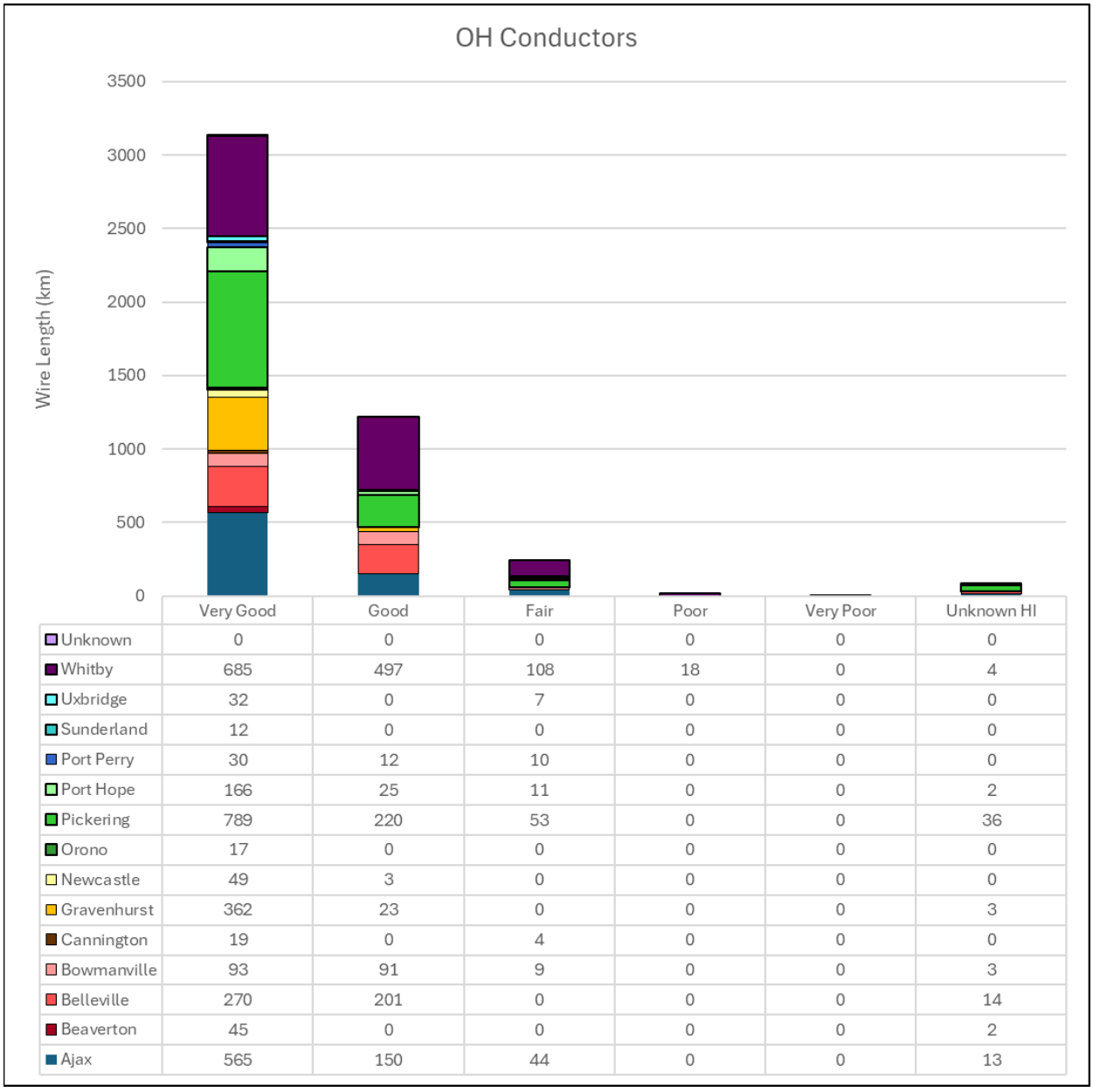


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	1291	15	2	4
Uxbridge	38	0	0	0
Sunderland	12	0	0	0
Port Perry	52	0	0	0
Port Hope	203	0	0	2
Pickering	1059	0	3	36
Orono	17	0	0	0
Newcastle	52	0	0	0
Gravenhurst	384	0	0	3
Cannington	23	0	0	0
Bowmanville	193	0	0	3
Belleville	471	0	0	14
Beaverton	45	0	0	2
Ajax	754	4	0	13

Figure 17: Overhead Conductor Age Distribution

4.1.5.4. HI Results

The HI distribution for OH conductors is presented in Figure 18. The majority of Elexicon's OH conductors are in Very Good condition. Approximately 18 km of OH conductors are in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	685	497	108	18	0	4
Uxbridge	32	0	7	0	0	0
Sunderland	12	0	0	0	0	0
Port Perry	30	12	10	0	0	0
Port Hope	166	25	11	0	0	2
Pickering	789	220	53	0	0	36
Orono	17	0	0	0	0	0
Newcastle	49	3	0	0	0	0
Gravenhurst	362	23	0	0	0	3
Cannington	19	0	4	0	0	0
Bowmanville	93	91	9	0	0	3
Belleville	270	201	0	0	0	14
Beaverton	45	0	0	0	0	2
Ajax	565	150	44	0	0	13

Figure 18: Overhead Conductor HI Results

4.1.6. Pole-Mounted Transformers

4.1.6.1. Condition Assessment Methodology

Pole-mounted transformers are another large asset class within the utility system. This asset category is made up of multiple units, each with a modest replacement value Transformers are generally considered to be a run-to-failure asset class with little maintenance other than visual inspections. Transformers may be replaced in planned projects based on identifiable degradation, pole line rebuilds, road relocations, and upgrade projects in response to customer load growth.

Transformers typically reach their end-of-life due to physical tank deterioration such as corrosion, which in extreme cases can lead to an instance of leaking oil. Where corrosion is detected, a transformer may be cycled back to the shop and re-painted with gaskets being replaced. Other modes of failure include overheated connections due to loosened connectors, which are typically detected in infrared scanning and tightened to reduce the failure risk.

Most commonly, utilities replace distribution transformers as part of overhead or underground rebuild projects. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified.



Figure 19: Image of a Pole-Mounted Transformer

Table 10 below the HI algorithm for pole-mounted transformers. The HIF is a two-parameter formulation. There was not enough data available to incorporate visual inspection into the HIF. Additional details about these condition parameters and how they are graded can be found in Appendix A.6.

Table 10: Pole-Mounted Transformer HIF

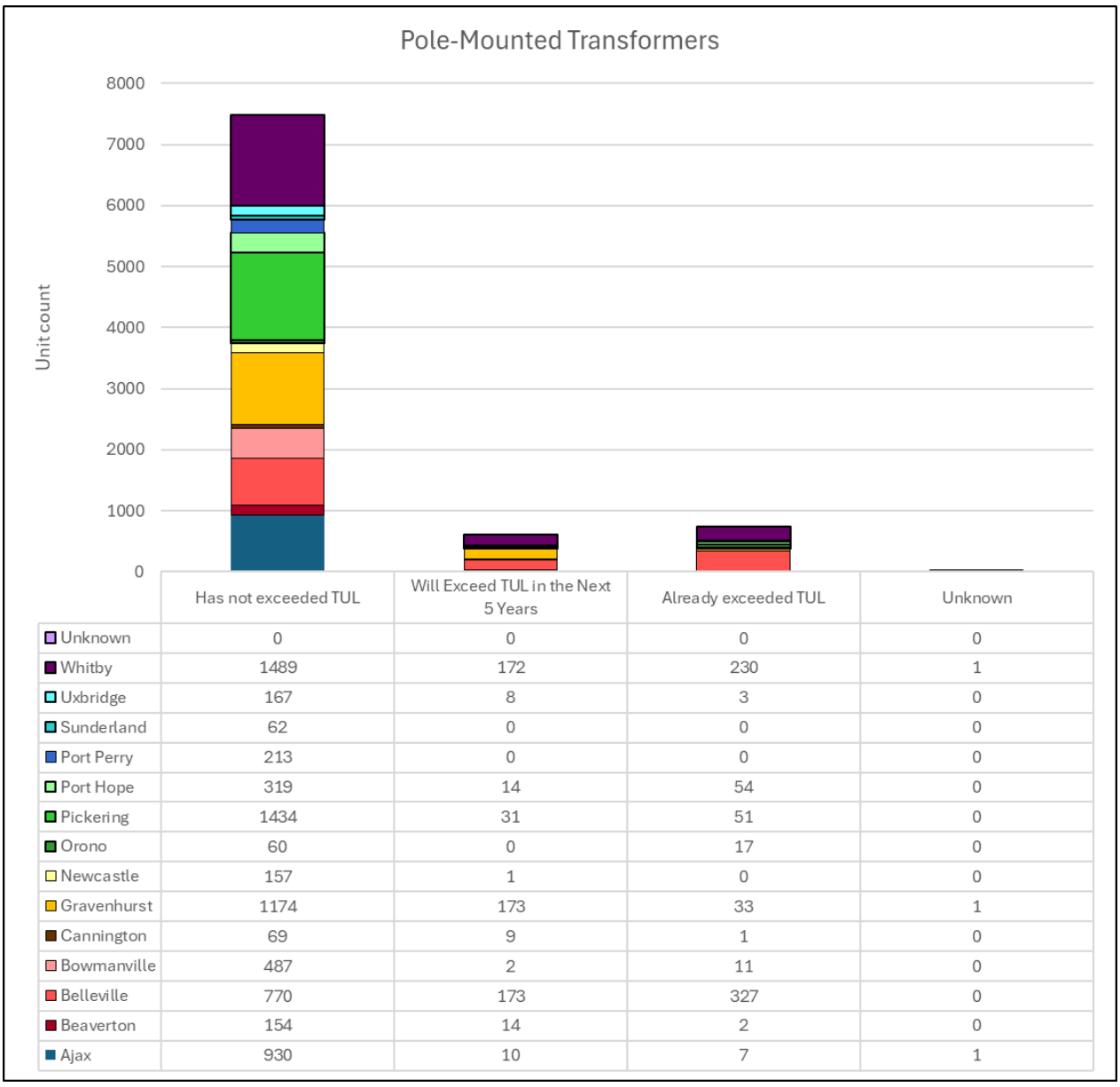
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Infrared Scanning	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				20

4.1.6.2. Data Collection and Assumptions

Elexicon has 8,831 pole-mounted transformers. Service Age is available for 100% of pole-mount transformers. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. Infrared scanning was performed on the entire overhead system. It was assumed that assets that do not have an infrared report did not have an elevated temperature and are scored 'A' in the Infrared Scanning condition. The average DAI for pole-mounted transformers is 100%.

4.1.6.3. Demographics

Figure 20 show the age distributions for the pole-mounted transformers. The TUL for pole-mounted transformers is 40 years.

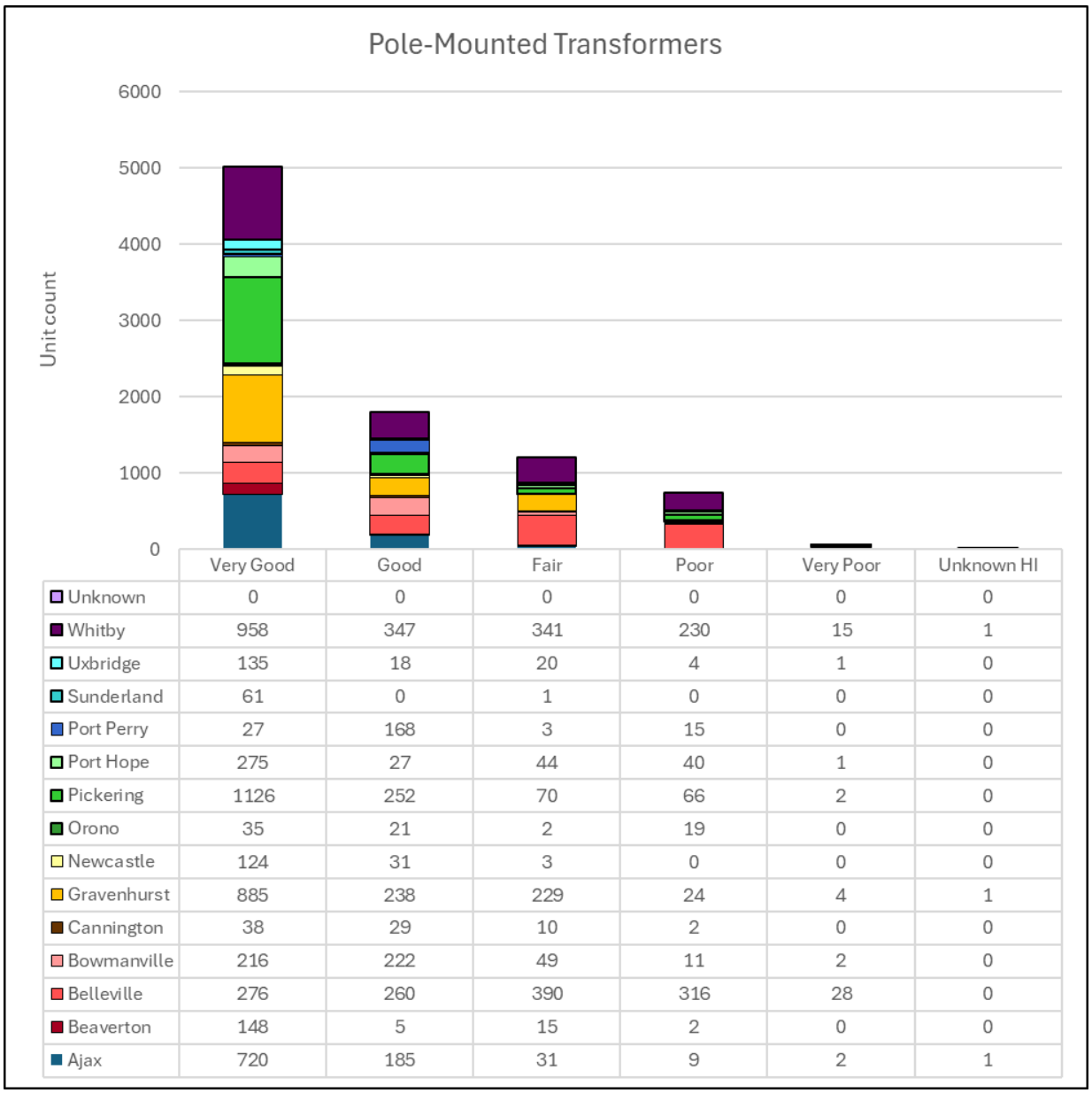


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	1489	172	230	1
Uxbridge	167	8	3	0
Sunderland	62	0	0	0
Port Perry	213	0	0	0
Port Hope	319	14	54	0
Pickering	1434	31	51	0
Orono	60	0	17	0
Newcastle	157	1	0	0
Gravenhurst	1174	173	33	1
Cannington	69	9	1	0
Bowmanville	487	2	11	0
Belleville	770	173	327	0
Beaverton	154	14	2	0
Ajax	930	10	7	1

Figure 20: Pole-Mounted Transformer Age Distribution

4.1.6.4. HI Results

The HI distribution for pole-mount transformers is shown in Figure 21. Majority of the transformers are in Very Good condition. There are 793 pole-mount transformers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	958	347	341	230	15	1
Uxbridge	135	18	20	4	1	0
Sunderland	61	0	1	0	0	0
Port Perry	27	168	3	15	0	0
Port Hope	275	27	44	40	1	0
Pickering	1126	252	70	66	2	0
Orono	35	21	2	19	0	0
Newcastle	124	31	3	0	0	0
Gravenhurst	885	238	229	24	4	1
Cannington	38	29	10	2	0	0
Bowmanville	216	222	49	11	2	0
Belleville	276	260	390	316	28	0
Beaverton	148	5	15	2	0	0
Ajax	720	185	31	9	2	1

Figure 21: Pole-Mounted Transformer HI Results

4.1.7. Pad-Mounted Transformers

4.1.7.1. Condition Assessment Methodology

Pad-mounted transformers convert power as single-phase or three-phase units and are typically a run-to-failure asset, although transformers may be renewed as part of a planned program. Apart from painting the tanks, replacing damaged bushings, or repairing leaky gaskets, most utilities carry out very little preventative maintenance or testing on distribution transformers.

Transformers typically reach their end-of-life due to physical tank deterioration, such as corrosion which, in extreme cases, can lead to oil leaks. Where corrosion is detected, a transformer may be cycled back to the shop, re-painted, and gaskets can be replaced. Other modes of failure include overheated connections due to loosened connectors which are typically detected in infrared scanning and tightened. Sometimes the deterioration of civil infrastructures such as pads and duct banks contribute to the decision to replace a pad-mounted transformer.

Utilities generally replace pad-mounted transformers during underground rebuild projects or when increases in load patterns develop. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified.

The HI for pad-mounted transformers is a two-factor formulation consisting of age and overall condition with the dominant factor being condition. Since the Overall Condition relies on visual inspection, age represents a material portion of the overall HI scoring, as it acts as a proxy for the degradation processes affecting the internal workings of transformers that are not visible during visual assessments and are not economical to subject to empirical testing used on station transformers. An example of a pad-mounted transformer is shown below.



Figure 22: Image of a Pad-Mounted Transformer

Table 11 below provides the HI algorithm for pad-mounted transformers. Additional details about these condition parameters and how they are graded can be found in Appendix A.7.

Table 11: Pad-Mounted Transformer HIF

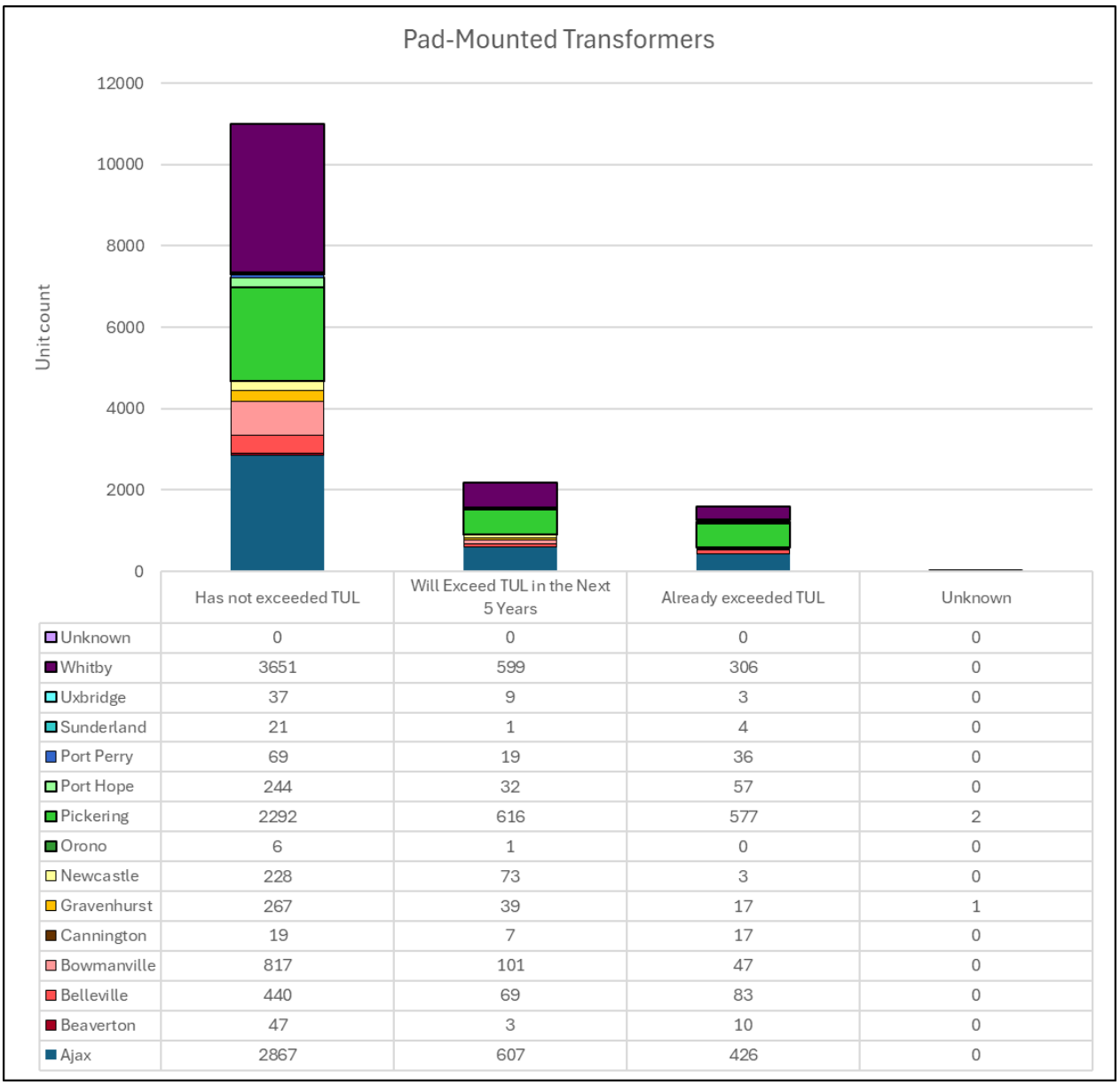
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Total Score				28

4.1.7.2. Data Collection and Assumptions

Service age is available for 100% of pad-mounted transformers. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. Overall condition is available for 93% of pad-mount transformers. Missing age data was extrapolated based on the age of adjacent assets. The average DAI for pad-mounted transformers is 96%.

4.1.7.3. Demographics

Within Elexicon's distribution system, there are 14,770 pad-mounted transformers. Figure 23 presents the age distribution pad-mounted transformers. The TUL for pad-mounted transformers is 40 years.

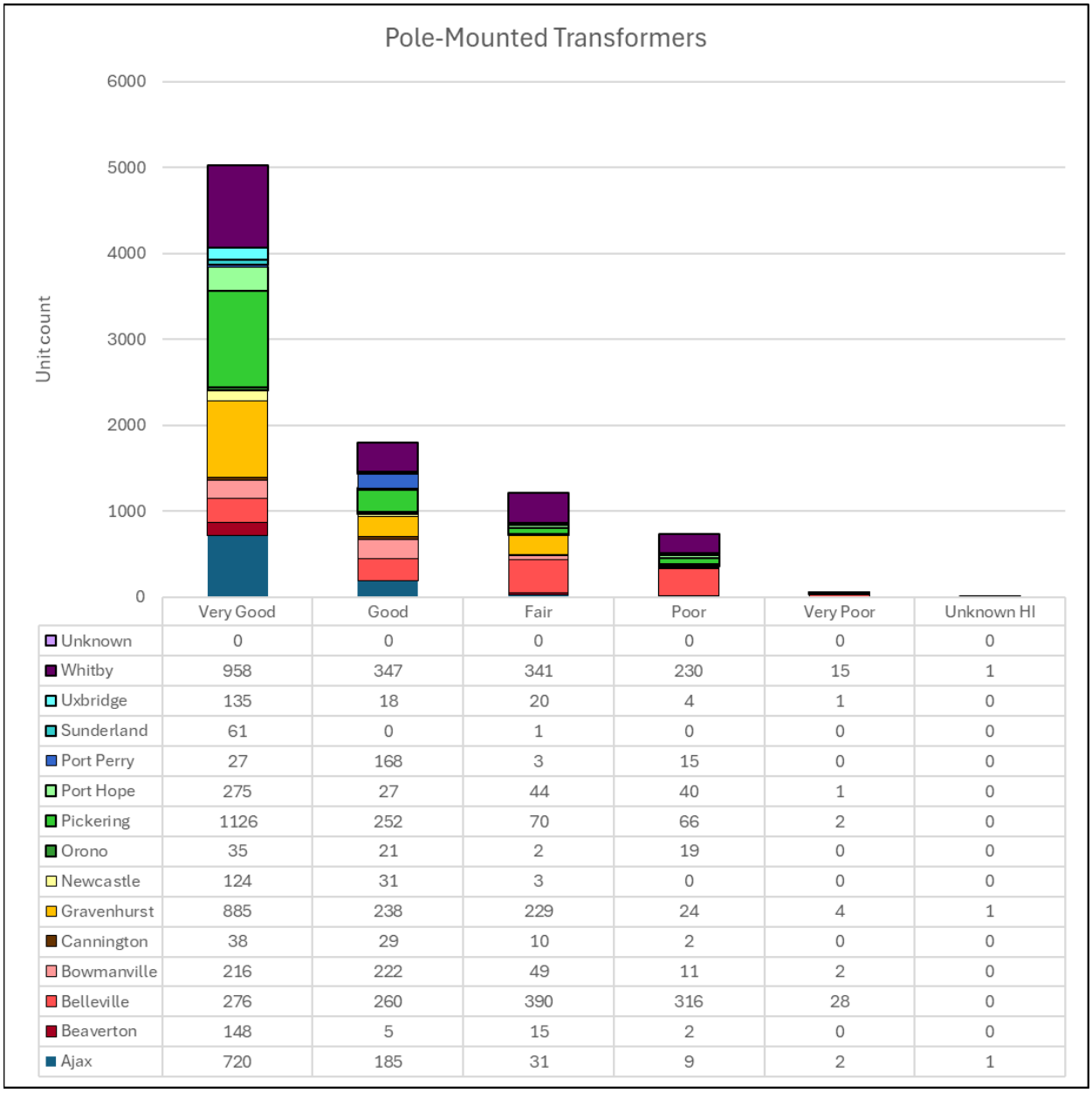


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	3651	599	306	0
Uxbridge	37	9	3	0
Sunderland	21	1	4	0
Port Perry	69	19	36	0
Port Hope	244	32	57	0
Pickering	2292	616	577	2
Orono	6	1	0	0
Newcastle	228	73	3	0
Gravenhurst	267	39	17	1
Cannington	19	7	17	0
Bowmanville	817	101	47	0
Belleville	440	69	83	0
Beaverton	47	3	10	0
Ajax	2867	607	426	0

Figure 23: Pad-Mounted Transformer Age Distribution

4.1.7.4. HI Results

The HI distribution for pad-mounted transformers are shown in Figure 24. Most pad-mount transformers are in Very Good condition. There are 1077 pad-mounted transformers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	958	347	341	230	15	1
Uxbridge	135	18	20	4	1	0
Sunderland	61	0	1	0	0	0
Port Perry	27	168	3	15	0	0
Port Hope	275	27	44	40	1	0
Pickering	1126	252	70	66	2	0
Orono	35	21	2	19	0	0
Newcastle	124	31	3	0	0	0
Gravenhurst	885	238	229	24	4	1
Cannington	38	29	10	2	0	0
Bowmanville	216	222	49	11	2	0
Belleville	276	260	390	316	28	0
Beaverton	148	5	15	2	0	0
Ajax	720	185	31	9	2	1

Figure 24: Pad-Mounted Transformer HI Results

4.1.8. Vault Transformers

4.1.8.1. Condition Assessment Methodology

Vault transformers can be located on a customer's premises in a vault accessible only to LDC staff, or sometimes are located in a sidewalk vault on the right of way. Apart from painting the tanks, replacing damaged bushings, or repairing leaky gaskets, most utilities carry out very little preventative maintenance or testing on distribution transformers.

Transformers typically reach their end-of-life due to physical tank deterioration such as corrosion which, in extreme cases, can lead to oil leaks. Where corrosion is observed, a transformer may be cycled back to the shop, re-painted, and gaskets can be replaced. Other modes of failure include overheated connections due to loosened connectors, which are typically detected in infrared scanning and tightened. Sometimes the deterioration of civil infrastructures, such as the doors and vents, contributes to the decision to rehabilitate a vault transformer.

Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified. An example of a vault transformer is shown below.



Figure 25: Image of a Vault Transformer

Table 12 below provides the HI algorithm for vault transformers. The HIF for vault transformers is a single-factor formulation consisting of the service age. Once data availability improves, overall condition should be added to the formulation. Additional details about the condition parameters can be found in Appendix A.8.

Table 12: Vault Transformer HIF

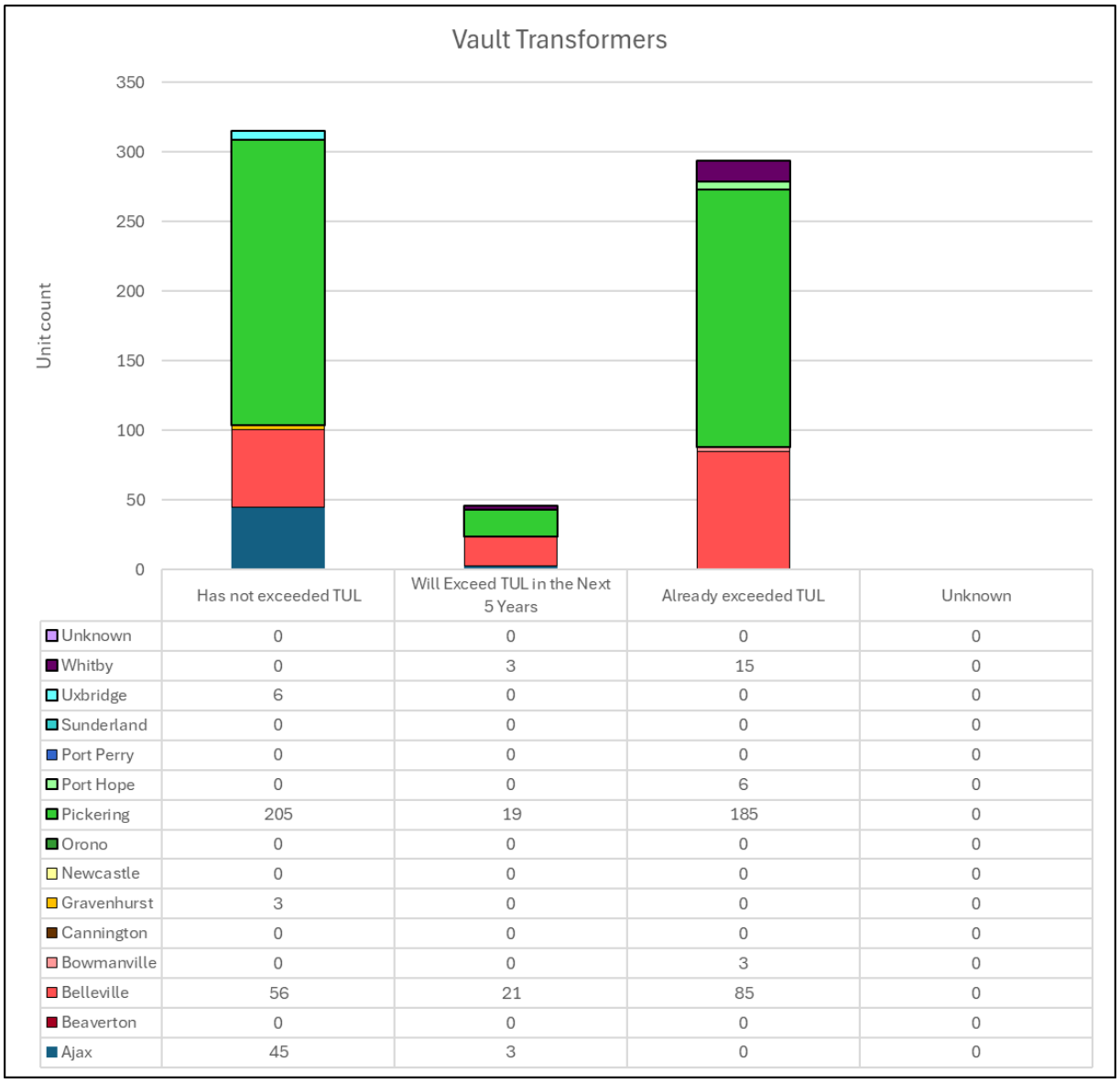
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				12

4.1.8.2. Data Collection and Assumptions

Elexicon has 655 vault transformers. Service age is available for 100% of vault transformers. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. The average DAI for vault transformers is 100%.

4.1.8.3. Demographics

Figure 26 shows the age distributions for vault transformers. The TUL for vault transformers is 35 years.

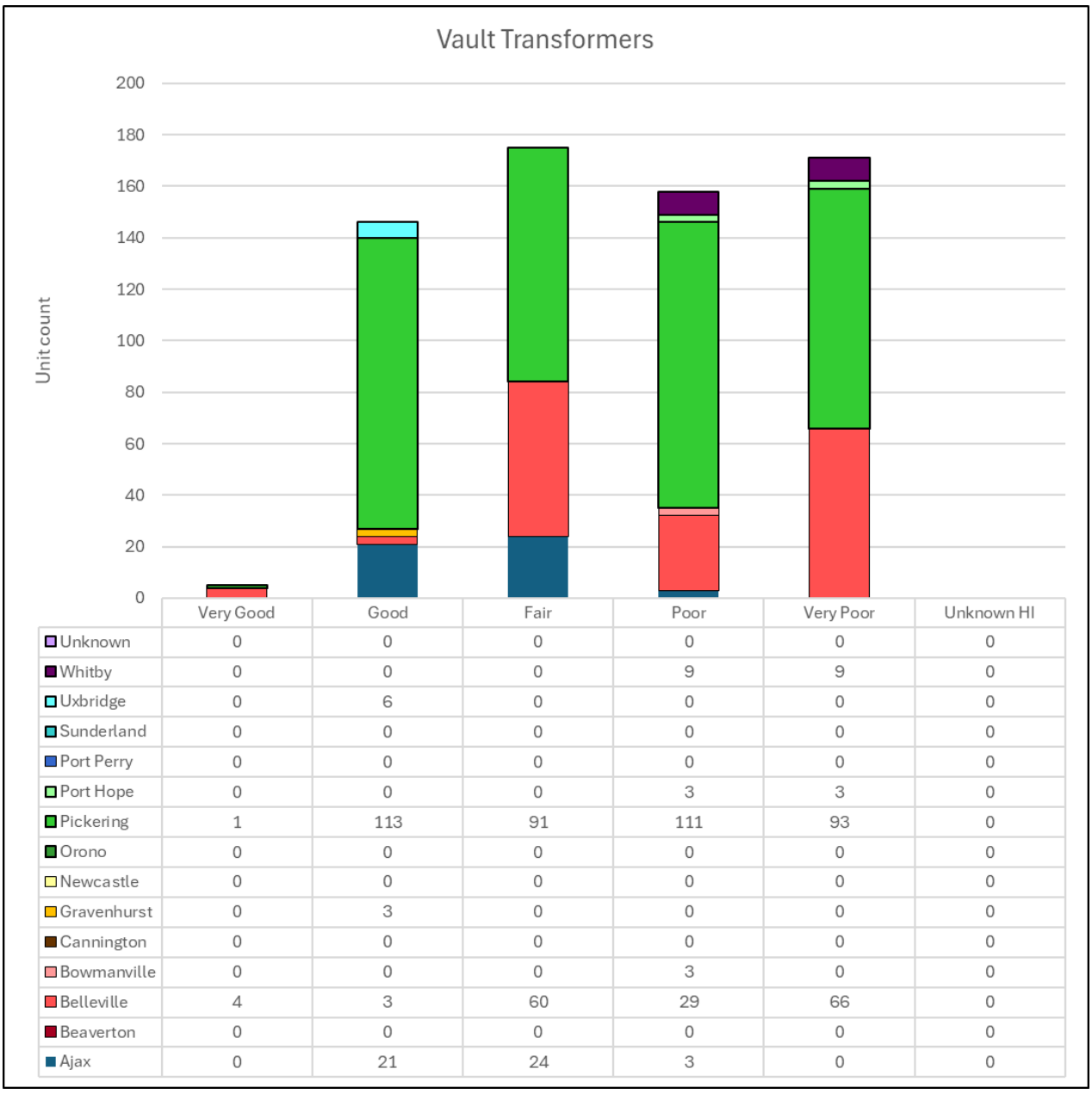


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	0	3	15	0
Uxbridge	6	0	0	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	0	0	6	0
Pickering	205	19	185	0
Orono	0	0	0	0
Newcastle	0	0	0	0
Gravenhurst	3	0	0	0
Cannington	0	0	0	0
Bowmanville	0	0	3	0
Belleville	56	21	85	0
Beaverton	0	0	0	0
Ajax	45	3	0	0

Figure 26: Vault Transformer Age Distribution

4.1.8.4. HI Results

The HI distribution for vault transformers is shown in Figure 27. Most vault transformers are in Good to Very Poor condition. There are 329 vault transformers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	0	0	0	9	9	0
Uxbridge	0	6	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	0	0	0	3	3	0
Pickering	1	113	91	111	93	0
Orono	0	0	0	0	0	0
Newcastle	0	0	0	0	0	0
Gravenhurst	0	3	0	0	0	0
Cannington	0	0	0	0	0	0
Bowmanville	0	0	0	3	0	0
Belleville	4	3	60	29	66	0
Beaverton	0	0	0	0	0	0
Ajax	0	21	24	3	0	0

Figure 27: Vault Transformer HI Results

4.1.9. Step Transformers

4.1.9.1. Condition Assessment Methodology

Step transformers are transformer units which are used to convert primary voltages, such as 27.6 kV to 4.16 kV. Similar to pole-mount or pad-mount transformers, step transformers can be overhead or underground. Examples of a step transformers are shown below.



Figure 28: Image of an OH Step Transformer and UG Step Transformer (from left to right)

Table 13 below provides the HI algorithm for submersible transformers. The HIF for Step transformers is a single-factor formulation consisting of the service age. Once data availability improves, overall condition should be added to the formulation. Additional details about the condition parameters can be found in Appendix A.8.

Table 13: Step Transformer HIF

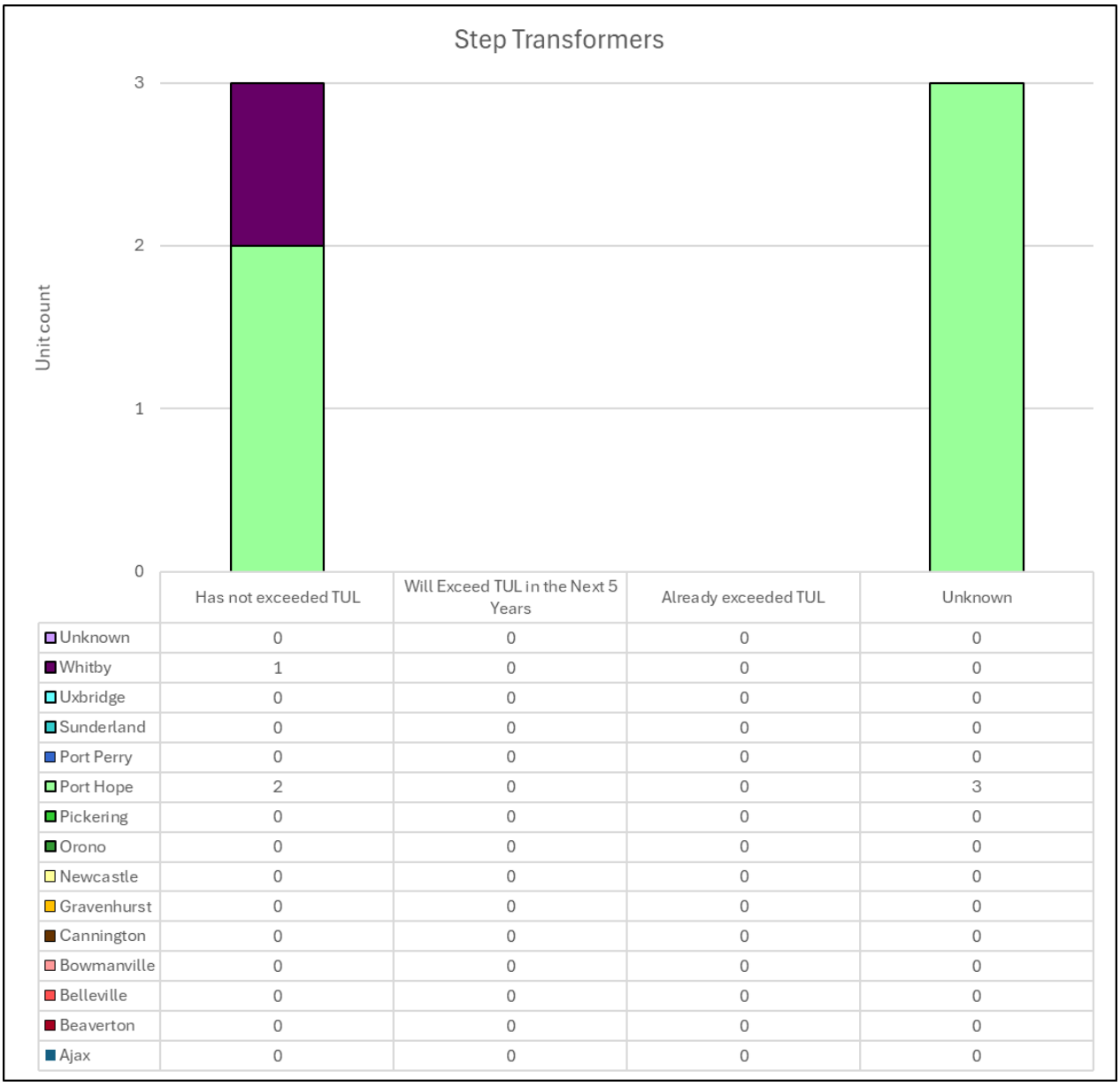
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				12

4.1.9.2. Data Collection and Assumptions

Elexicon has 6 step transformers. Service age is available for 50% of Step transformers. The average DAI for step transformers is 50%.

4.1.9.3. Demographics

Figure 29 shows the age distributions for step transformers. The TUL for Step transformers is 40 years.

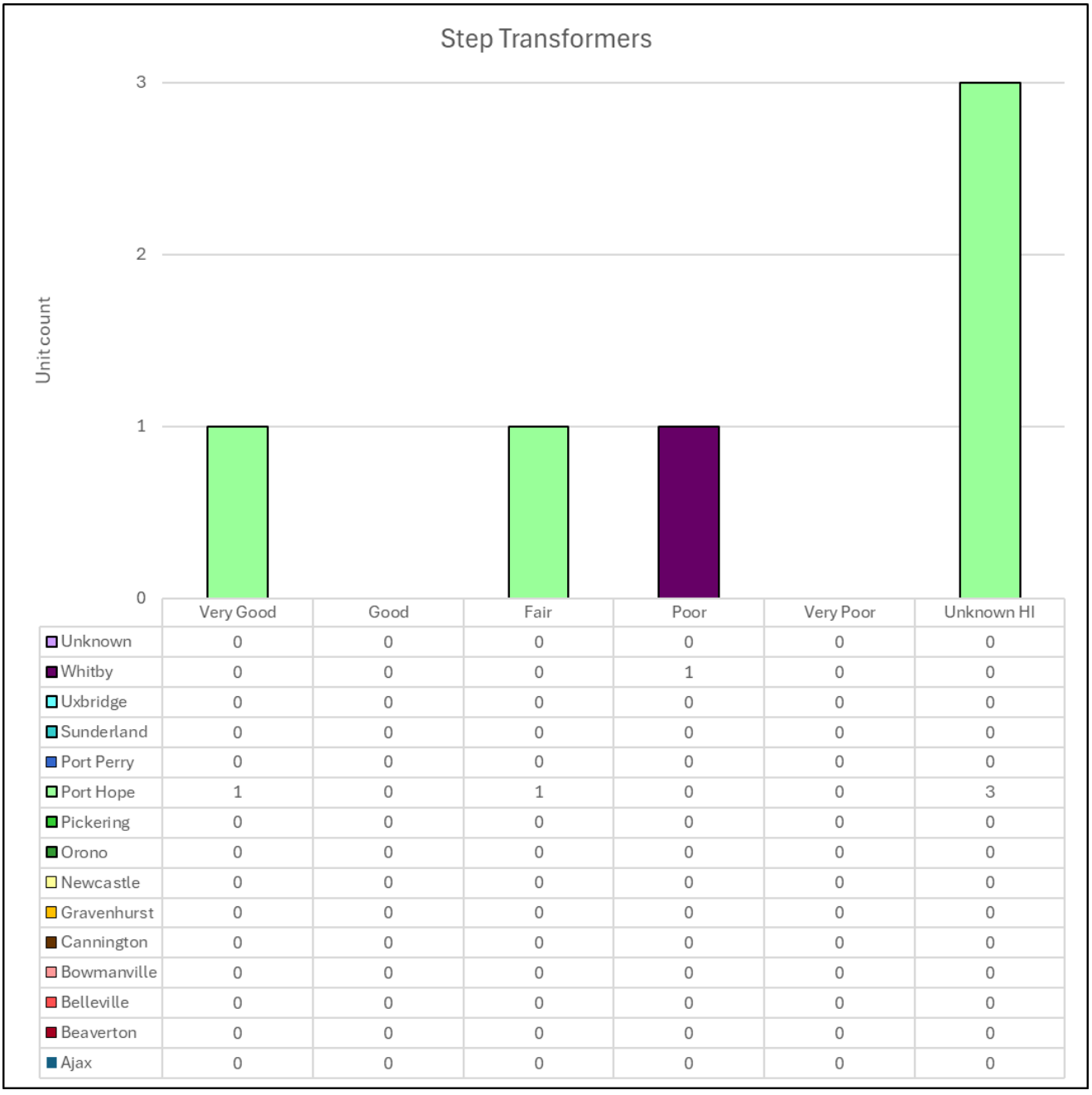


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	1	0	0	0
Uxbridge	0	0	0	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	2	0	0	3
Pickering	0	0	0	0
Orono	0	0	0	0
Newcastle	0	0	0	0
Gravenhurst	0	0	0	0
Cannington	0	0	0	0
Bowmanville	0	0	0	0
Belleville	0	0	0	0
Beaverton	0	0	0	0
Ajax	0	0	0	0

Figure 29: Step Transformer Age Distribution

4.1.9.4. HI Results

The HI distribution for Step transformers is shown in Figure 30. Due to limited age data availability, most transformers have Unknown HI. There is one step transformer in Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	0	0	0	1	0	0
Uxbridge	0	0	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	1	0	1	0	0	3
Pickering	0	0	0	0	0	0
Orono	0	0	0	0	0	0
Newcastle	0	0	0	0	0	0
Gravenhurst	0	0	0	0	0	0
Cannington	0	0	0	0	0	0
Bowmanville	0	0	0	0	0	0
Belleville	0	0	0	0	0	0
Beaverton	0	0	0	0	0	0
Ajax	0	0	0	0	0	0

Figure 30: Step Transformer HI Results

4.1.10. Submersible Transformers

4.1.10.1. Condition Assessment Methodology

Submersible transformers are specialized electrical devices designed for installation in submerged or watery environments. These transformers are constructed with sealed enclosures to protect their internal components from water and other potentially corrosive substances.

The HIF for submersible transformers is a two-factor formulation consisting of the overall condition. This is not a robust formulation; however, since it relies on an observation recorded in the field, it does provide value for planners. An example of a submersible transformer is below.



Figure 31: Image of a Submersible Transformer

Table 14 below provides the HI algorithm for submersible transformers. Additional details about the condition parameters can be found in Appendix A.9.

Table 14: Submersible Transformer HIF

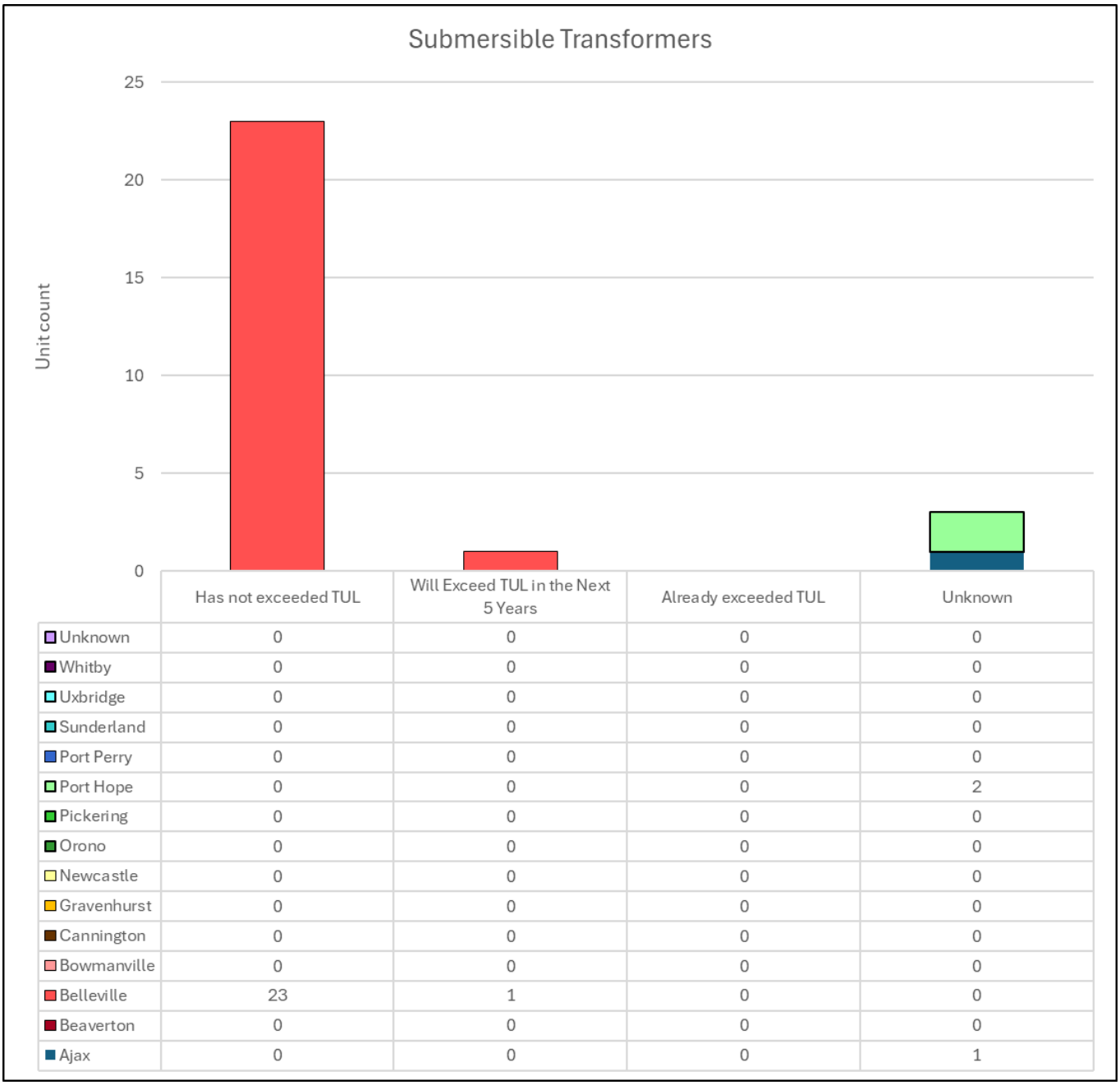
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				28

4.1.10.2. Data Collection and Assumptions

Elexicon has 27 submersible transformers. Service age is available for 89% of submersible transformers. Overall condition is available for 93% of submersible transformers. The average DAI for submersible transformers is 91%.

4.1.10.3. Demographics

Figure 32 shows the age distributions for submersible transformers. The TUL for submersible transformers is 35 years.

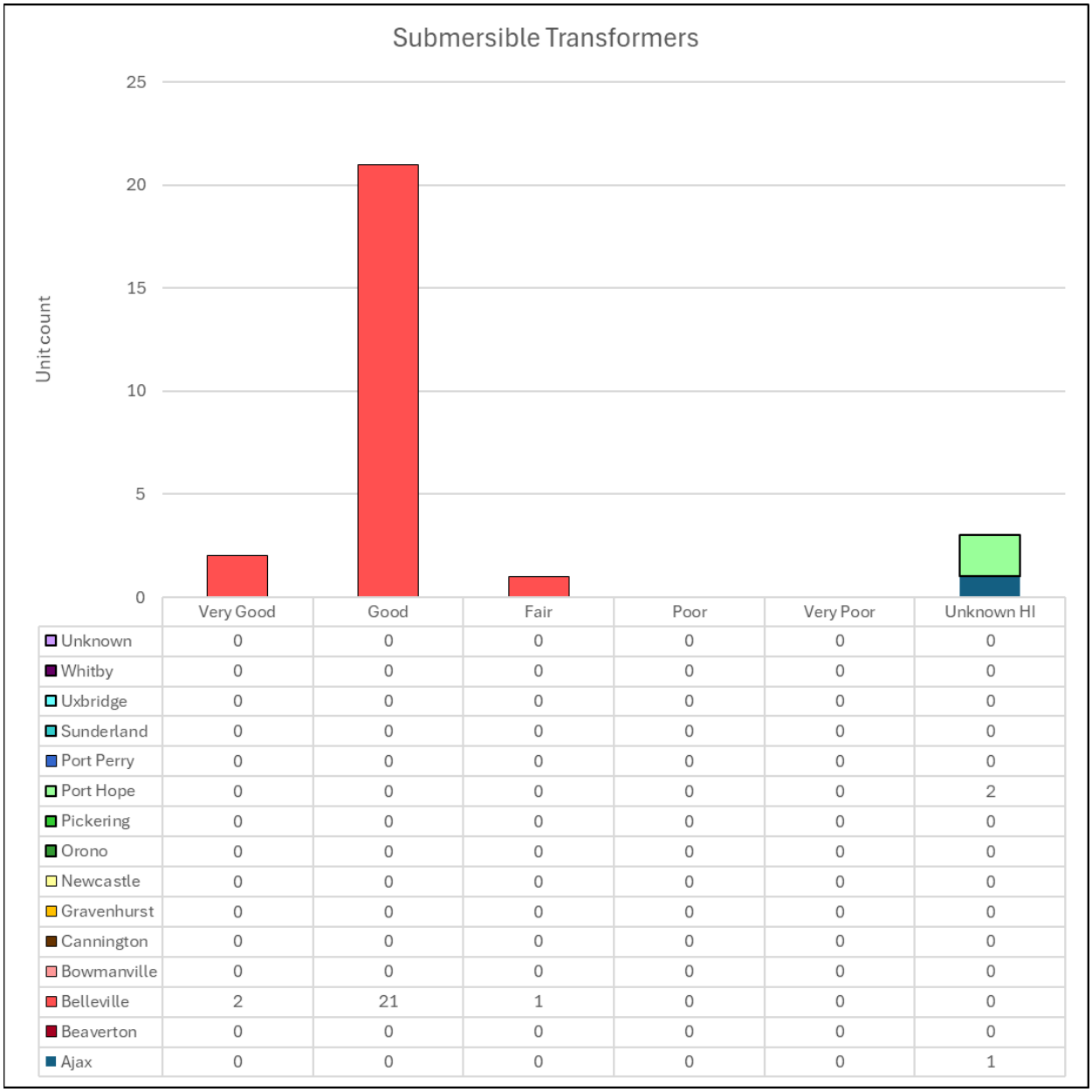


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	0	0	0	0
Uxbridge	0	0	0	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	0	0	0	2
Pickering	0	0	0	0
Orono	0	0	0	0
Newcastle	0	0	0	0
Gravenhurst	0	0	0	0
Cannington	0	0	0	0
Bowmanville	0	0	0	0
Belleville	23	1	0	0
Beaverton	0	0	0	0
Ajax	0	0	0	1

Figure 32: Submersible Transformer Age Distribution

4.1.10.4. HI Results

The HI distribution for submersible transformers is shown in Figure 33. Most submersible transformers are in Good condition. There are no submersible transformers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	0	0	0	0	0	0
Uxbridge	0	0	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	0	0	0	0	0	2
Pickering	0	0	0	0	0	0
Orono	0	0	0	0	0	0
Newcastle	0	0	0	0	0	0
Gravenhurst	0	0	0	0	0	0
Cannington	0	0	0	0	0	0
Bowmanville	0	0	0	0	0	0
Belleville	2	21	1	0	0	0
Beaverton	0	0	0	0	0	0
Ajax	0	0	0	0	0	1

Figure 33: Submersible Transformer HI Results

4.1.11. Pad-Mounted Distribution Switchgears

4.1.11.1. Condition Assessment Methodology

Pad-mounted switchgear is a major sub-class of the switch asset group. Switchgear can be air-, oil-, or SF6-insulated; can contain fuses or vacuum interrupters and can be operated manually or remotely via automation schemes and SCADA.

Typical end-of-life indicators for pad-mounted switchgear are related to physical deterioration of the enclosure, the internal workings of the switchgear, and in some cases the extent of deterioration to the concrete pad. Preventative maintenance options for switchgear may include the replacement of components such as interphase barriers, arc chutes, and high-pressure cleaning.

The HIF for switchgears typically uses service age, visual inspections, and IR scan results as condition parameters. Elexicon's distribution switchgear HIF consists of service age, visual inspection parameters, IR scan results. Visual inspection includes the condition of barriers, terminations, switchblades, operating mechanism, and pad. An example of a pad-mounted distribution switchgear is below.



Figure 34: Image of a Distribution Switchgear

Table 15 below provides the HI algorithm for pad-mounted distribution switchgears. Additional details about these condition parameters and how they are graded can be found in Appendix A.10.

Table 15: Pad-Mounted Distribution Switchgear HIF

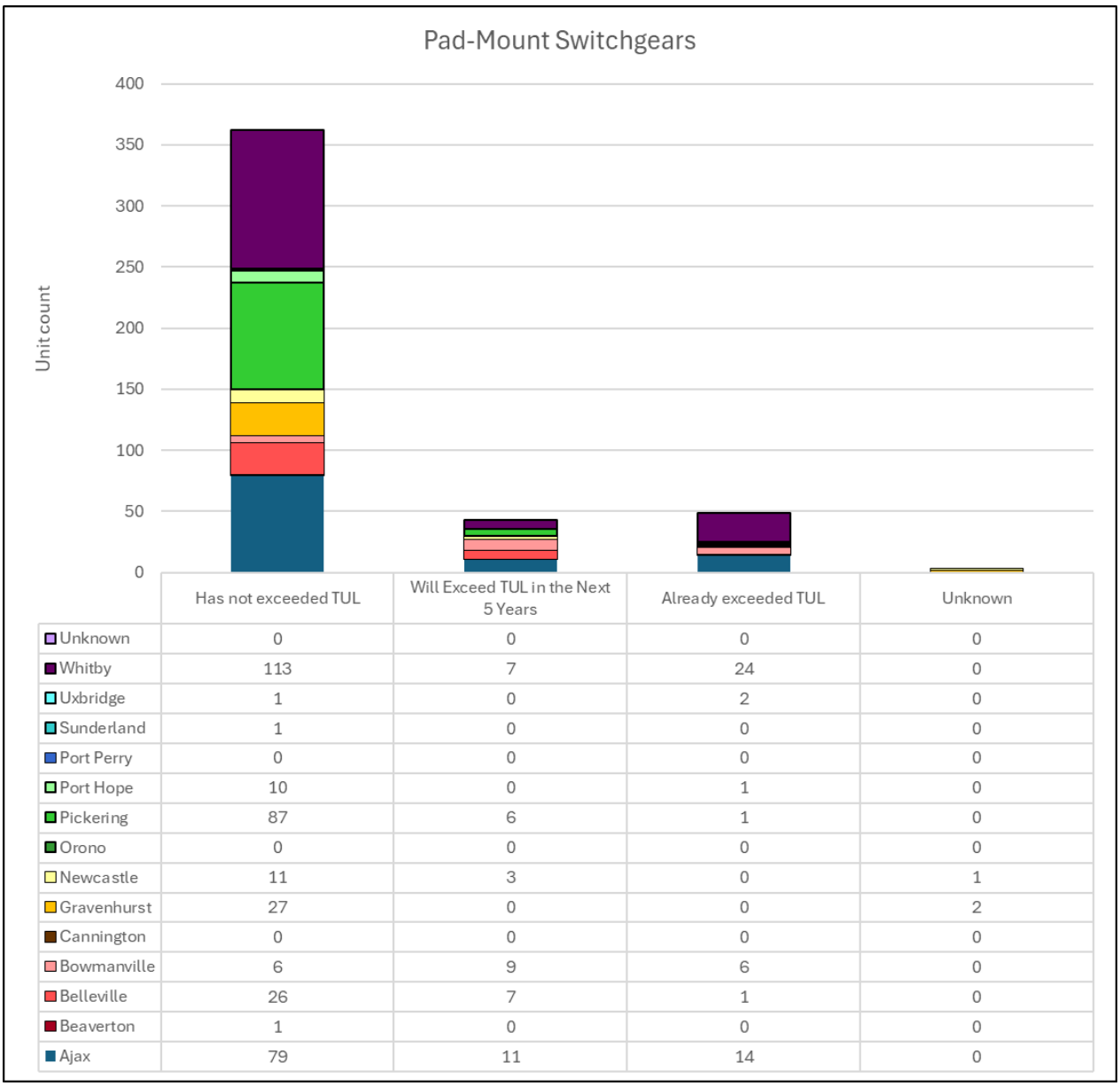
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
IR Scan	2	A,D	4,1	8
Condition of Pad	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Operating Mechanism	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Termination	2	A,B,C,D,E	4,3,2,1,0	8
Barriers	2	A,B,C,D,E	4,3,2,1,0	8
Condition of Enclosure	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				56

4.1.11.2. Data Collection and Assumptions

Service age is available for 99% of distribution switchgears. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. Data for Barriers was only available for 55% of pad-mount switch gears, The average DAI for the pad-mounted switchgear is 81%.

4.1.11.3. Demographics

Elexicon owns 457 pad-mounted distribution switchgear. Figure 35 presents the age distribution for in-service pad-mounted switchgear. The TUL for pad-mounted switchgears is 30 years.

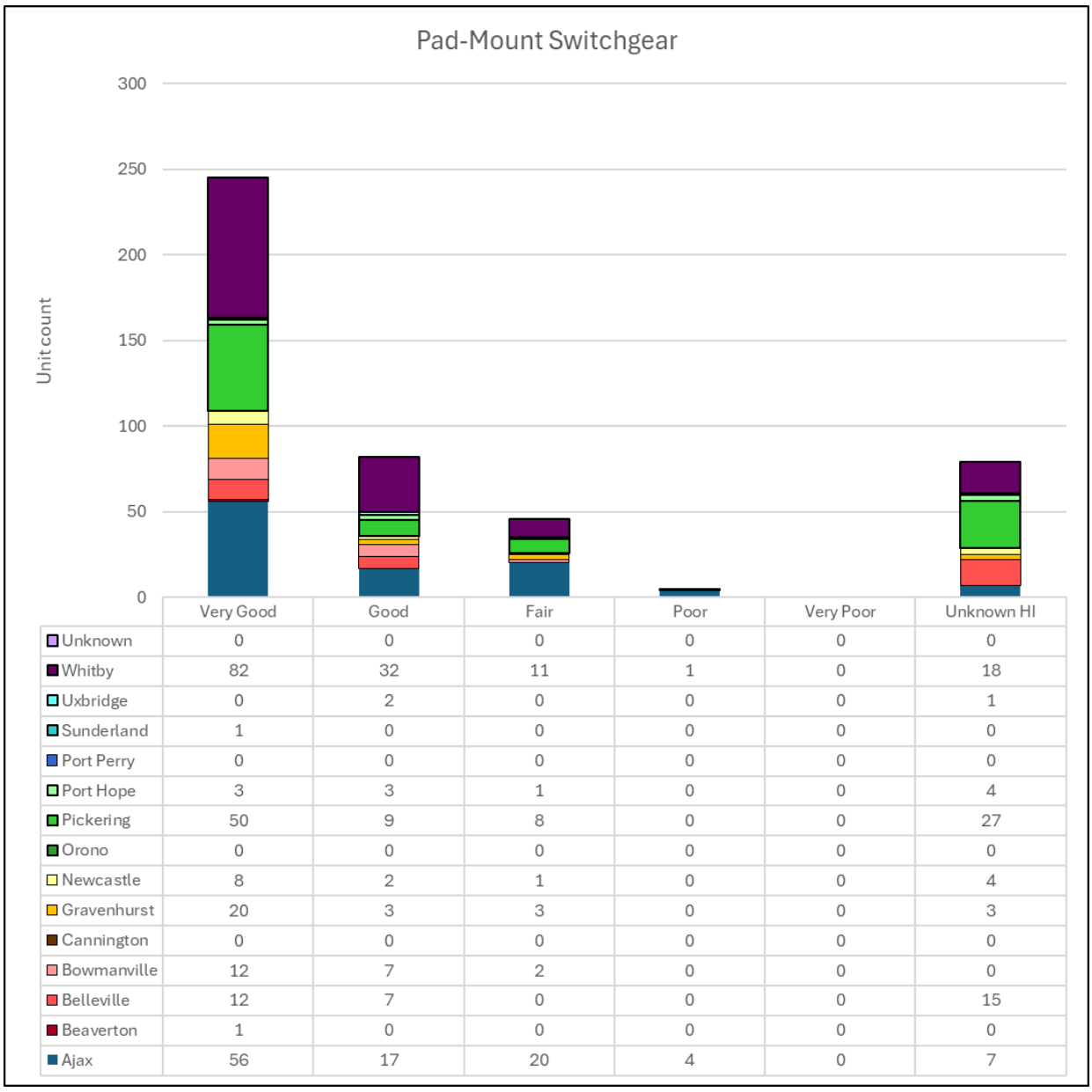


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	113	7	24	0
Uxbridge	1	0	2	0
Sunderland	1	0	0	0
Port Perry	0	0	0	0
Port Hope	10	0	1	0
Pickering	87	6	1	0
Orono	0	0	0	0
Newcastle	11	3	0	1
Gravenhurst	27	0	0	2
Cannington	0	0	0	0
Bowmanville	6	9	6	0
Belleville	26	7	1	0
Beaverton	1	0	0	0
Ajax	79	11	14	0

Figure 35: Pad-Mounted Distribution Switchgear Age Distribution

4.1.11.4. HI Results

The HI distribution for pad-mounted switchgears is shown in Figure 36. Most pad-mount switchgears are in Very Good condition. There are 5 pad-mounted switchgears in Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	82	32	11	1	0	18
Uxbridge	0	2	0	0	0	1
Sunderland	1	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	3	3	1	0	0	4
Pickering	50	9	8	0	0	27
Orono	0	0	0	0	0	0
Newcastle	8	2	1	0	0	4
Gravenhurst	20	3	3	0	0	3
Cannington	0	0	0	0	0	0
Bowmanville	12	7	2	0	0	0
Belleville	12	7	0	0	0	15
Beaverton	1	0	0	0	0	0
Ajax	56	17	20	4	0	7

Figure 36: Pad-Mounted Distribution Switchgear HI Results

4.1.12. Overhead Switches

4.1.12.1. Condition Assessment Methodology

Overhead switches are essential components of distribution systems, providing load disconnection and isolation for various equipment configurations. This section encompasses both single-phase and three-phase overhead switches, each serving distinct purposes within the distribution network.

Overhead switches are diverse in type and function, ranging from single-phase switches serving lateral and transformer connections to three-phase switches crucial for distribution infrastructure. Underground switches are excluded from this analysis as they are considered as a component of their associated switchgear.

Single-phase switches consist of fused switches and solid-blade disconnects, and they typically degrade due to physical corrosion, insulator tracking, and heat caused by loose connections. For three-phase switches, which include gang-operated, pole-mounted, and load interrupter variants, inspection focuses on identifying dirt, corrosion, and "hot" connections through visual and IR scans.



Figure 37: Images of a Fused Cut-out Switch, Fused Run-off Switch, and In-line Disconnect Switch (from left to right)

The HIF for distribution switches uses service age, visual inspections, and IR scan results as condition parameters. The resulting formulation is captured in Table 16. Additional details about the condition parameters above and they are graded can be found in Appendix A.11.

Table 16: Overhead Switches HIF

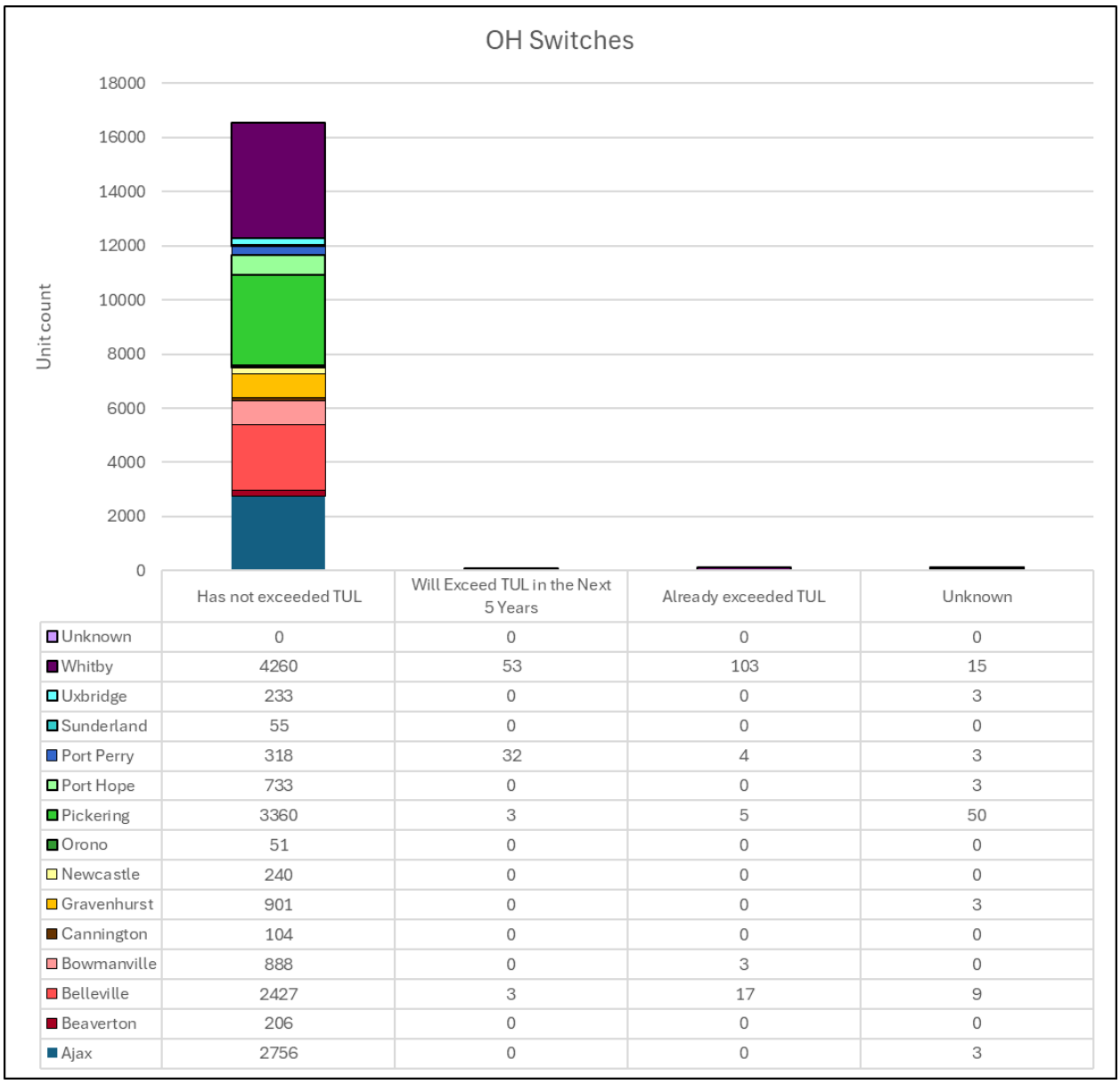
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				24

4.1.12.2. Data Collection and Assumptions

Service age is available for 99% of overhead switches. If age data was missing for a particular asset, it was estimated based on the average age of its adjacent assets. Infrared scanning was performed on the entire overhead system. Only exceptions are reported so any devices that do not have an infrared report did not have an elevated temperature and are scored 'A' in the Infrared Scanning condition. The DAI for overhead switches asset is 86%.

4.1.12.3. Demographics

Elexicon owns 16,844 overhead switches. Figure 38 shows the age distributions for overhead switches. The TUL for overhead switches is 45 years.

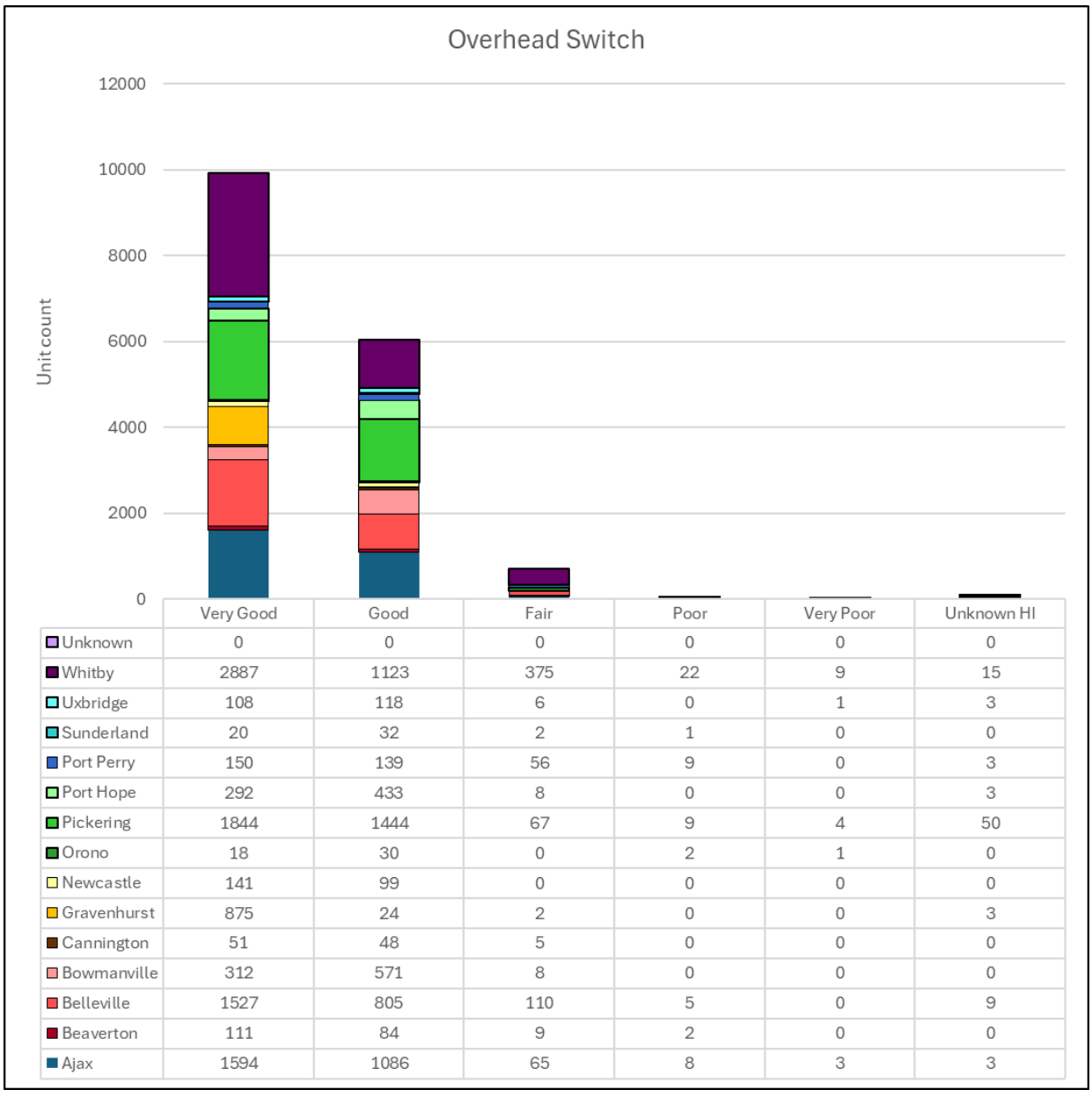


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	4260	53	103	15
Uxbridge	233	0	0	3
Sunderland	55	0	0	0
Port Perry	318	32	4	3
Port Hope	733	0	0	3
Pickering	3360	3	5	50
Orono	51	0	0	0
Newcastle	240	0	0	0
Gravenhurst	901	0	0	3
Cannington	104	0	0	0
Bowmanville	888	0	3	0
Belleville	2427	3	17	9
Beaverton	206	0	0	0
Ajax	2756	0	0	3

Figure 38: Overhead Switch Age Distribution

4.1.12.4. HI Results

Figure 39 shows the HI distribution of Elexicon's overhead switches. Most overhead switches are in Very Good condition. There are 76 OH switches in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	2887	1123	375	22	9	15
Uxbridge	108	118	6	0	1	3
Sunderland	20	32	2	1	0	0
Port Perry	150	139	56	9	0	3
Port Hope	292	433	8	0	0	3
Pickering	1844	1444	67	9	4	50
Orono	18	30	0	2	1	0
Newcastle	141	99	0	0	0	0
Gravenhurst	875	24	2	0	0	3
Cannington	51	48	5	0	0	0
Bowmanville	312	571	8	0	0	0
Belleville	1527	805	110	5	0	9
Beaverton	111	84	9	2	0	0
Ajax	1594	1086	65	8	3	3

Figure 39: Overhead Switch HI Results

4.2. Station Assets

This section describes those assets which represent the main station assets of the distribution system. Other assets are located at some stations which may be too minor to track. The following sections outline the Condition Assessment Methodology used for the station assets in scope.

4.2.1. Power Transformers

4.2.1.1. Condition Assessment Methodology

Station power transformers are the single most critical asset class owned by an LDC. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers.

Degradation mechanisms include loss of insulation or oil quality due to overload or low-level internal faults causing heating, arcing, and/or physical deterioration such as corrosion or failed cooling systems. Station transformers are the most tested and tracked utility assets and reliable indicators of the impending need for maintenance or replacement include DGA, OQ and PF testing. Some tests can be conducted in-service and others required taking the asset out of service. Many features such as cooling fans are external to the tank and can be maintained in situ. An example of a power transformer is shown below.



Figure 40: Image of Station Power Transformer

Table 17 provides the HI algorithm for power transformers. Additional details about these condition parameters and how they are graded can be found in Appendix A.12. The HIF for power transformers is the most complex of all asset classes assessed. The top five key condition parameters indicated are DGA, OQ", service age, tap changer condition, and insulation resistance.

Table 17: Power Transformer HI Algorithm

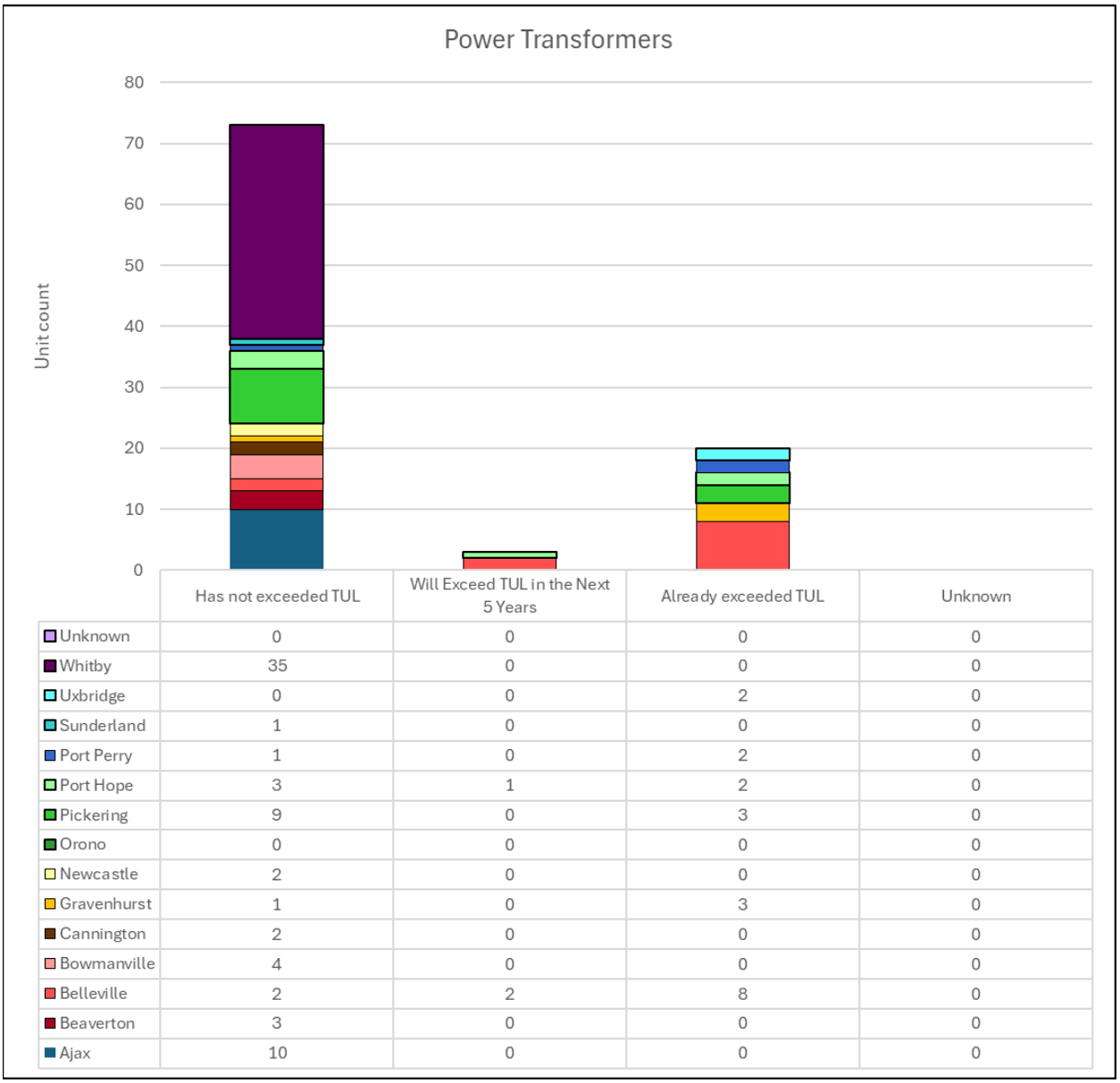
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	60	A, B, C, D, E	4,3,2,1,0	240
DGA	140	A, B, C, D, E	4,3,2,1,0	560
Oil Quality	58	A, C, E	4,2,0	232
Insulation Resistance	33.3	A, B, C, D, E	4,3,2,1,0	133.2
Bushing Electrical Test	25	A, B, C, D, E	4,3,2,1,0	100
Insulation PF	23.8	A, B, C, D, E	4,3,2,1,0	95.2
Turns Test Ratio	19	A, B, C, D, E	4,3,2,1,0	76
DC Winding Resistance	19	A, B, C, D, E	4,3,2,1,0	76
Concrete Pad Condition	7.5	B,C,D	3,2,1	22.5
Paint Condition	7.5	B,C,D	3,2,1	22.5
Oil Leaks	35	B,C,D	3,2,1	105
Oil Level	3.8	B,C,D	3,2,1	11.4
Breather/Silica Gel	2.5	B,C,D	3,2,1	7.5
Gauges	1.3	B,C,D	3,2,1	3.9
Gas Relay	2.5	B,C,D	3,2,1	7.5
Fans	2.5	B,C,D	3,2,1	7.5
Fan Control	2.5	B,C,D	3,2,1	7.5
Control Cabinet	5	B,C,D	3,2,1	15
Control Cabinet Heater	5	B,C,D	3,2,1	15
Enclosures	18.8	B,C,D	3,2,1	56.4
Bushings	25	B,C,D	3,2,1	75
Insulators	2.5	B,C,D	3,2,1	7.5
Lightning Arresters	1.3	B,C,D	3,2,1	3.9
Off Load Tap Changer Condition	50	B,C,D	3,2,1	150
Nitrogen Tank and Plumbing	2.5	B,C,D	3,2,1	7.5
Total Score				2038

4.2.1.2. Data Collection and Assumptions

Due to the limited availability of data for Elexicon's spare transformers, only in-service units were considered in the ACA. Substations are inspected on a monthly basis and data is typically collected on detailed inspection, testing, and maintenance forms. The average DAI for power transformers is 96%.

4.2.1.3. Demographics

Elexicon has 96 in-service power transformers. Figure 41 presents the age distribution of Elexicon's power transformers. The TUL for power transformers is 45 years.

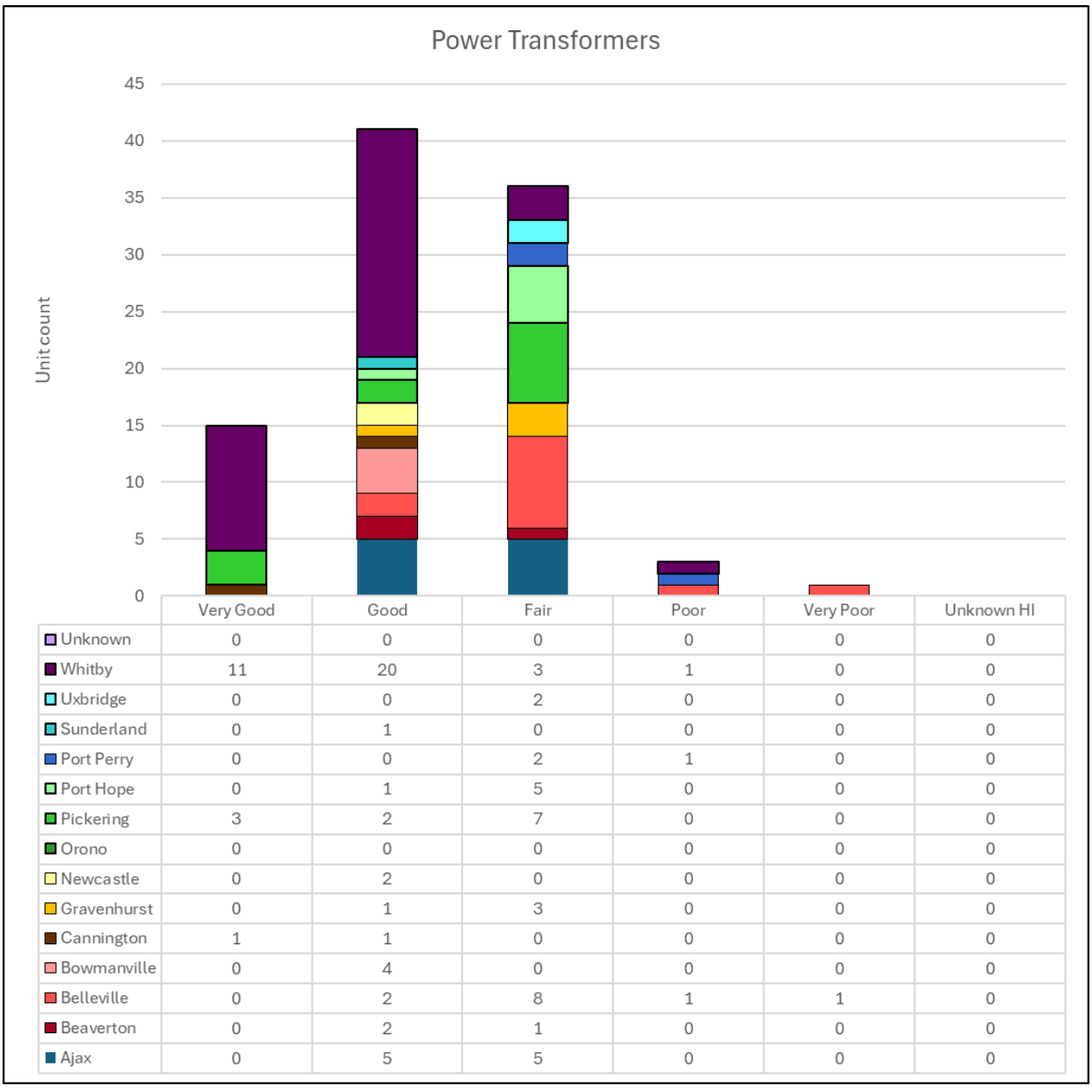


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	35	0	0	0
Uxbridge	0	0	2	0
Sunderland	1	0	0	0
Port Perry	1	0	2	0
Port Hope	3	1	2	0
Pickering	9	0	3	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	1	0	3	0
Cannington	2	0	0	0
Bowmanville	4	0	0	0
Belleville	2	2	8	0
Beaverton	3	0	0	0
Ajax	10	0	0	0

Figure 41: Station Transformer Age Demographics

4.2.1.4. HI Results

The HI distribution for power transformers is presented in Figure 42. Most of the power transformers are in Good to Fair condition. There are 4 power transformers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	11	20	3	1	0	0
Uxbridge	0	0	2	0	0	0
Sunderland	0	1	0	0	0	0
Port Perry	0	0	2	1	0	0
Port Hope	0	1	5	0	0	0
Pickering	3	2	7	0	0	0
Orono	0	0	0	0	0	0
Newcastle	0	2	0	0	0	0
Gravenhurst	0	1	3	0	0	0
Cannington	1	1	0	0	0	0
Bowmanville	0	4	0	0	0	0
Belleville	0	2	8	1	1	0
Beaverton	0	2	1	0	0	0
Ajax	0	5	5	0	0	0

Figure 42: Station Transformer HI Results

Station transformers in Fair condition should be considered for possible remedial work or replacement depending on the unit's criticality. Since power transformers are critical assets, both Fair, Poor, and Very Poor condition units are of concern. Table 18 lists the results of the ACA for Station Transformers in order of increasing HI.

Table 18: Station Transformers HI Results

Asset ID	HI
SIDNEY-M.S.12	29%
GARDEN-T2	40%
CATHARINE-T1	43%
BIGELOW-T1	48%
CENTRE-T2	51%
REID-M.S.11	51%
SANDY BEACH-T2	52%
APPLECROFT-TR2	53%
HERCHIMER-M.S.9	53%
EDGEHILL-M.S.13-T2	54%
TAUNTON WEST-T2	55%
CAVAN SOUTH-T1	57%
L.R. MABLEY-T1	57%
NOTION-T1	57%
BAY-T1	59%
PINERIDGE-Main	59%
SHUTER-T1	59%
TOWN CENTRE-T2	59%
WESTNEY HEIGHTS-T2	60%
FAIRPORT-T2	61%
JONES-M.S.1	61%
HOWARD WALKER-T1	63%
JAMES-T1	63%
TOWN CENTRE-T1	63%
CASCADE-M.S.7	64%
HARDER-M.S.6	64%
RIVERSIDE-M.S.4	64%
WESTNEY HEIGHTS-T1	64%
FAIRPORT-T1	65%
JAMES D COLLINS-T1	66%
CAVAN NORTH-T1	67%
CHURCH-M.S.8	67%
MAIN-T1	67%
APPLECROFT-TR1	68%
SQUIRES BEACH-T2	68%
UXBRIDGE EAST-T1	68%

SANDY BEACH-T1	70%
CRANDELL-T1	70%
FIRST-T1	70%
UXBRIDGE WEST-T1	70%
VICTORIA WEST-T4	70%
BELL SS-M.S.10	71%
THICKSON-T1	73%
VICTORIA WEST-T2	73%
ABILITIES CENTRE-T168	74%
BEAVERTON WEST-T75215	74%
BRADSHAW-B23T1	74%
PICKERING BEACH-T2	74%
EDGEHILL-M.S.5-T1	75%
MONARCH-T2	75%
THICKSON-T2	75%
W. LAWLER-T1	75%
GARDEN-T1	76%
LIBERTY NORTH-04	76%
SPRY-75257-T1	76%
BAY RIDGES-T1	77%
DOWTY-T1	77%
LAIDLAW-74153-T2	77%
PEACOCK-T1	77%
WILMOT-T1	77%
DPRS Training-T169	78%
SQUIRES BEACH-T1	78%
THICKSON-T3	78%
BREAKWATER PUMPING STATION-T167	79%
DES NEWMAN-T1	79%
MONARCH-T1	79%
SUNDERLAND-T1	79%
TAUNTON EAST-T3	79%
DES NEWMAN-T3	80%
PICKERING BEACH-T1	80%
VICTORIA WEST-T1	80%
DES NEWMAN-T4	81%
SPRY-51015-T2	81%
TAUNTON EAST-T2	81%

TAUNTON WEST-T1	81%
TORONTO-T1	81%
WILLIAM GILLESPIE-T1	81%
ROSSLAND EAST-T3	82%
TAUNTON EAST-T1	82%
CONLIN-T1	85%
W. LAWLER-T2	85%
SEAT-T1	86%
SEAT-T2	86%
THICKSON-T4	86%
CONLIN-T3	87%
CONLIN-T2	87%
SEAT-T3	87%
LAIDLAW-74152-T1	88%
BALDWIN-T1	89%
CENTRE-T1	89%
ROSSLAND EAST-T4	91%
DES NEWMAN-T2	92%
ROSSLAND EAST-T1	92%
ROSSLAND EAST-T2	92%
ROSSLAND WEST-T1	92%
TAUNTON WEST-T3	93%

4.2.2. Circuit Breakers and Reclosers

4.2.2.1. Condition Assessment Methodology

Station circuit breakers and pad-mounted reclosers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. They work with station relays to open, either in a fault situation, as directed by the operations center, or as part of the automation scheme.

Breaker and recloser degradation occur primarily through physical processes, such as corrosion, accumulation of debris on insulators, or operations under load. In general, the more current passing through the breaker when it operates, the more wear and tear it sustains.

Breakers can be traditional oil breakers that can be maintained by cleaning carbon by-products from the oil, vacuum-bottle insulated, SF6 gas, or solid-dielectric insulation. An example of a circuit breaker is shown below.



Figure 43: Image of Circuit Breaker

Table 19 below provides the HI algorithm for station circuit breakers and reclosers. Additional details about these condition parameters and how they are graded can be found in Appendix A.13.

Table 19: Station Circuit Breaker and Recloser Health Index Algorithm

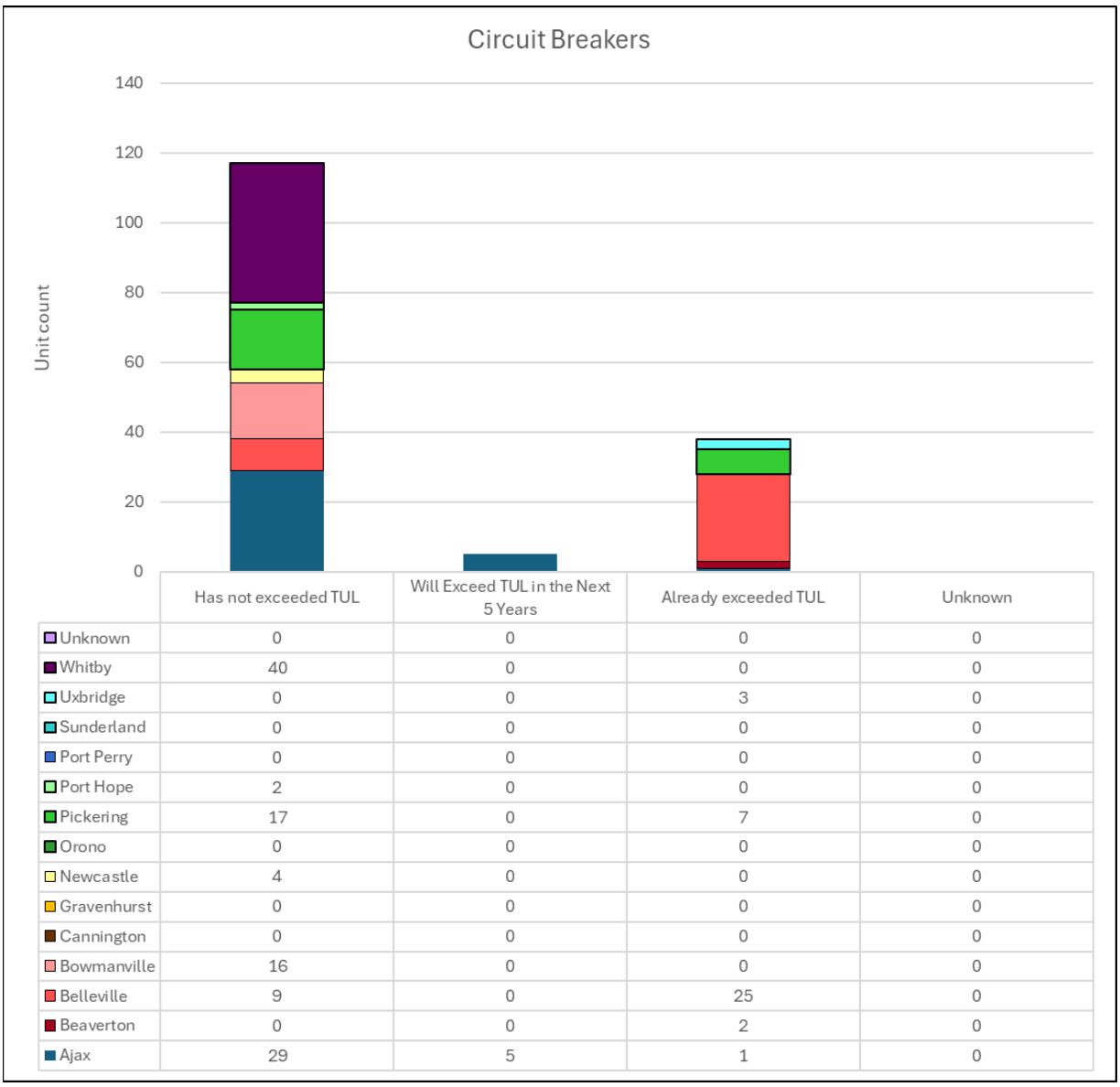
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A, B, C, D, E	4,3,2,1,0	8
Electrical Testing	2	A, B, C, D, E	4,3,2,1,0	8
Functional Obsolescence	2	A, E	4,0	8
Visual Inspection	1	A, B, C, D, E	4,3,2,1,0	4
Total Score				28

4.2.2.2. Data Collection and Assumptions

Condition data for circuit breakers is collected through detailed inspection, testing, and maintenance forms. The average DAI for circuit breakers is 99%.

4.2.2.3. Demographics

Elexicon owns 160 circuit breakers and reclosers. Figure 44 presents the age distribution for in-service circuit breakers and reclosers. The TUL for circuit breakers is 45 years.

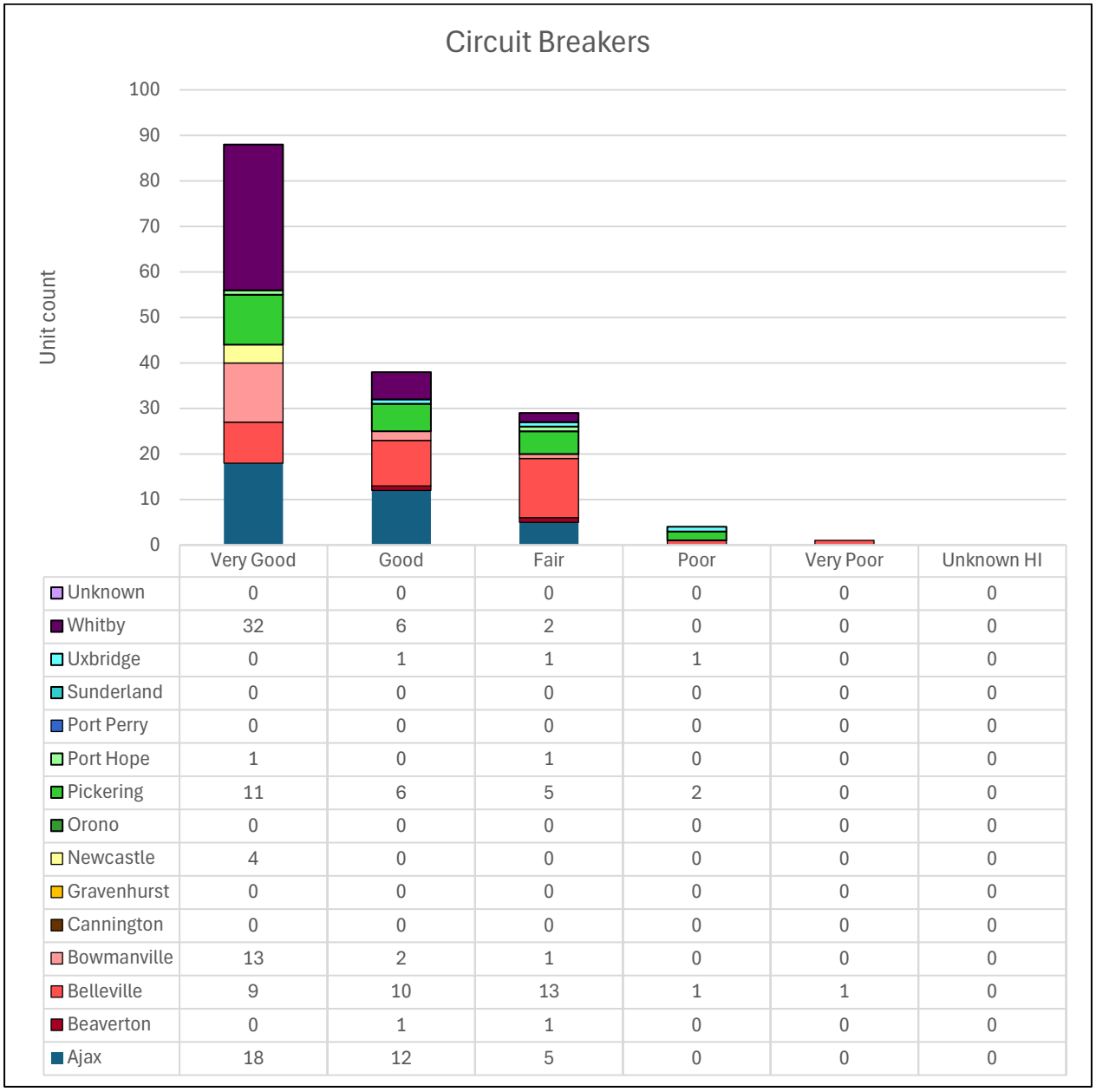


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	40	0	0	0
Uxbridge	0	0	3	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	2	0	0	0
Pickering	17	0	7	0
Orono	0	0	0	0
Newcastle	4	0	0	0
Gravenhurst	0	0	0	0
Cannington	0	0	0	0
Bowmanville	16	0	0	0
Belleville	9	0	25	0
Beaverton	0	0	2	0
Ajax	29	5	1	0

Figure 44: Circuit Breaker Age Distribution

4.2.2.4. HI Results

The overall HI distribution is presented in Figure 45. Most circuit breakers and reclosers are in Very Good condition. There are 5 circuit breakers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	32	6	2	0	0	0
Uxbridge	0	1	1	1	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	1	0	1	0	0	0
Pickering	11	6	5	2	0	0
Orono	0	0	0	0	0	0
Newcastle	4	0	0	0	0	0
Gravenhurst	0	0	0	0	0	0
Cannington	0	0	0	0	0	0
Bowmanville	13	2	1	0	0	0
Belleville	9	10	13	1	1	0
Beaverton	0	1	1	0	0	0
Ajax	18	12	5	0	0	0

Figure 45: Circuit Breaker HI Results

4.2.3. Station Switches

4.2.3.1. Condition Assessment Methodology

Station switches are critical substation assets that control the current flowing through the distribution system. Switch degradation occurs primarily through physical processes, such as corrosion and accumulation of debris. An example of a station switch is shown below.



Figure 46: Image of Station Switch

Table 20 below provides the HI algorithm for station switches. Additional details about these condition parameters and how they are graded can be found in Appendix A.14.

Table 20: Station Switches HI Algorithm

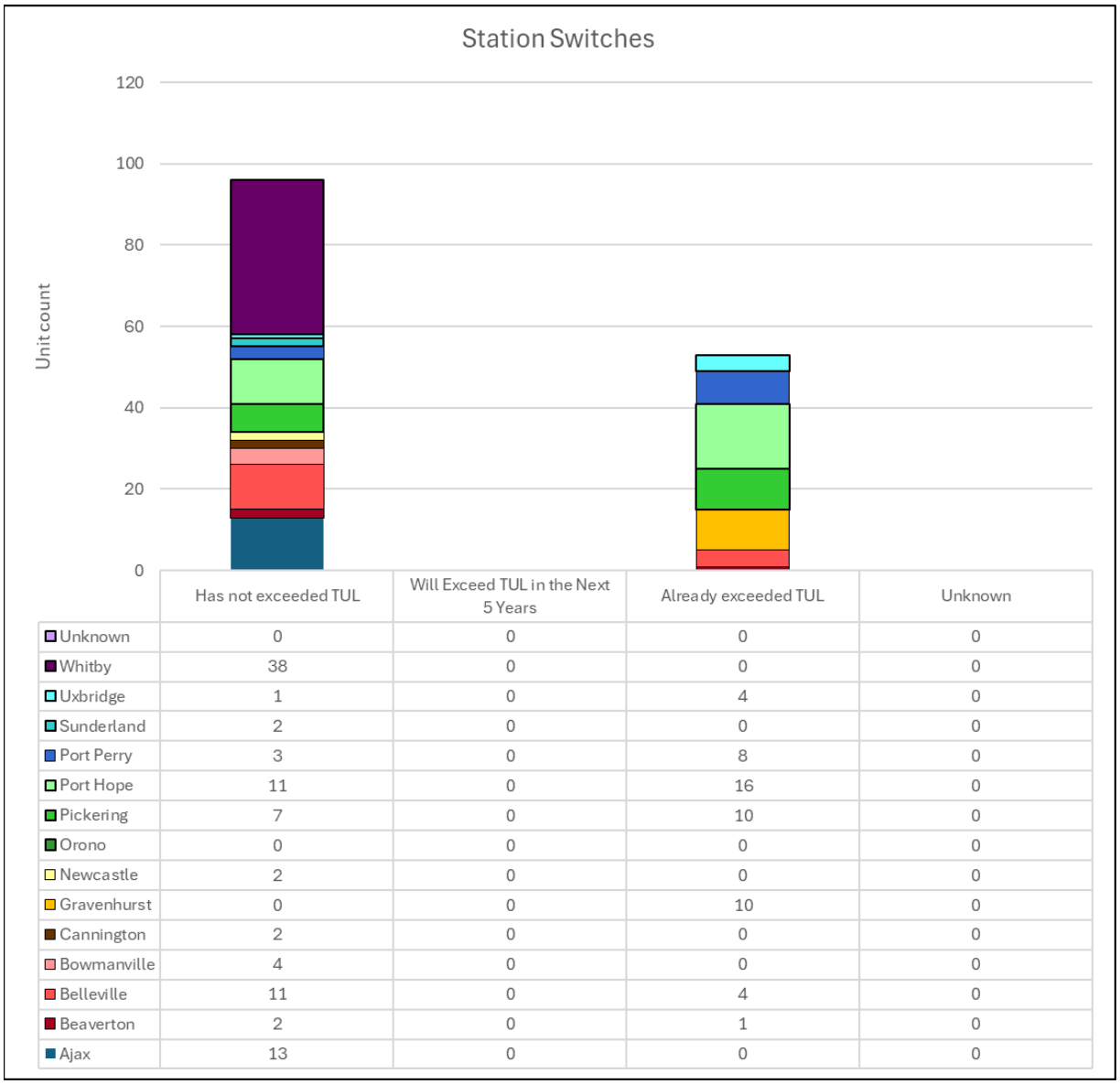
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	6	A,C,E	4,2,0	24
Contact Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Insulation Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				40

4.2.3.2. Data Collection and Assumptions

Condition data for station switches is collected through detailed inspection, testing, and maintenance forms. The average DAI for stations switches is 85%.

4.2.3.3. Demographics

Elexicon owns 149 station switches. Figure 47 presents the age distribution for in-service station switches. The TUL for station switches is 50 years.

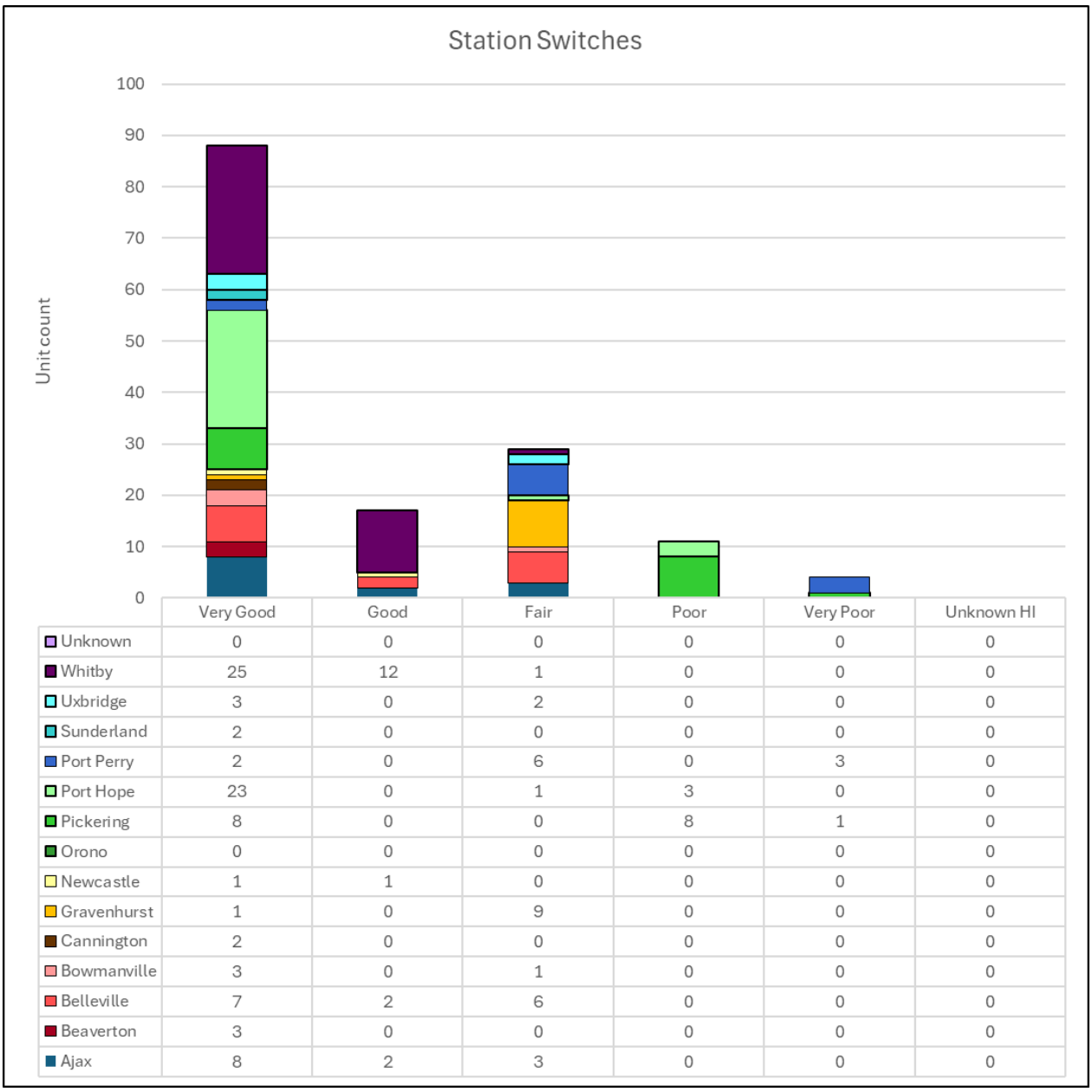


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	38	0	0	0
Uxbridge	1	0	4	0
Sunderland	2	0	0	0
Port Perry	3	0	8	0
Port Hope	11	0	16	0
Pickering	7	0	10	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	0	0	10	0
Cannington	2	0	0	0
Bowmanville	4	0	0	0
Belleville	11	0	4	0
Beaverton	2	0	1	0
Ajax	13	0	0	0

Figure 47: Station Switches Age Distribution

4.2.3.4. HI Results

The overall HI distribution is presented in Figure 48. Most station switches are in Very Good condition. There are 15 station switches in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	25	12	1	0	0	0
Uxbridge	3	0	2	0	0	0
Sunderland	2	0	0	0	0	0
Port Perry	2	0	6	0	3	0
Port Hope	23	0	1	3	0	0
Pickering	8	0	0	8	1	0
Orono	0	0	0	0	0	0
Newcastle	1	1	0	0	0	0
Gravenhurst	1	0	9	0	0	0
Cannington	2	0	0	0	0	0
Bowmanville	3	0	1	0	0	0
Belleville	7	2	6	0	0	0
Beaverton	3	0	0	0	0	0
Ajax	8	2	3	0	0	0

Figure 48: Station Switch HI Results

4.2.4. DC Backup Battery Supply

4.2.4.1. Condition Assessment Methodology

DC Backup Battery Supply includes station batteries and chargers. The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

Both the electrodes and electrolytes in control batteries undergo aging with repeated charge and discharge cycles, which result in a gradual reduction of battery storage capacity. The end-of-life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced, resulting in instances of chargers frequently outlasting the battery units. An example of a station battery is shown below.



Figure 49: Image of Battery

Table 21 provides the HI algorithm for Elexicon station batteries. Station chargers are assessed solely based on visual condition, and do not have an HI algorithm. Additional details about the condition parameters and how they are graded can be found in Appendix A.15 and A.16.

Table 21: Station Batteries HI Algorithm

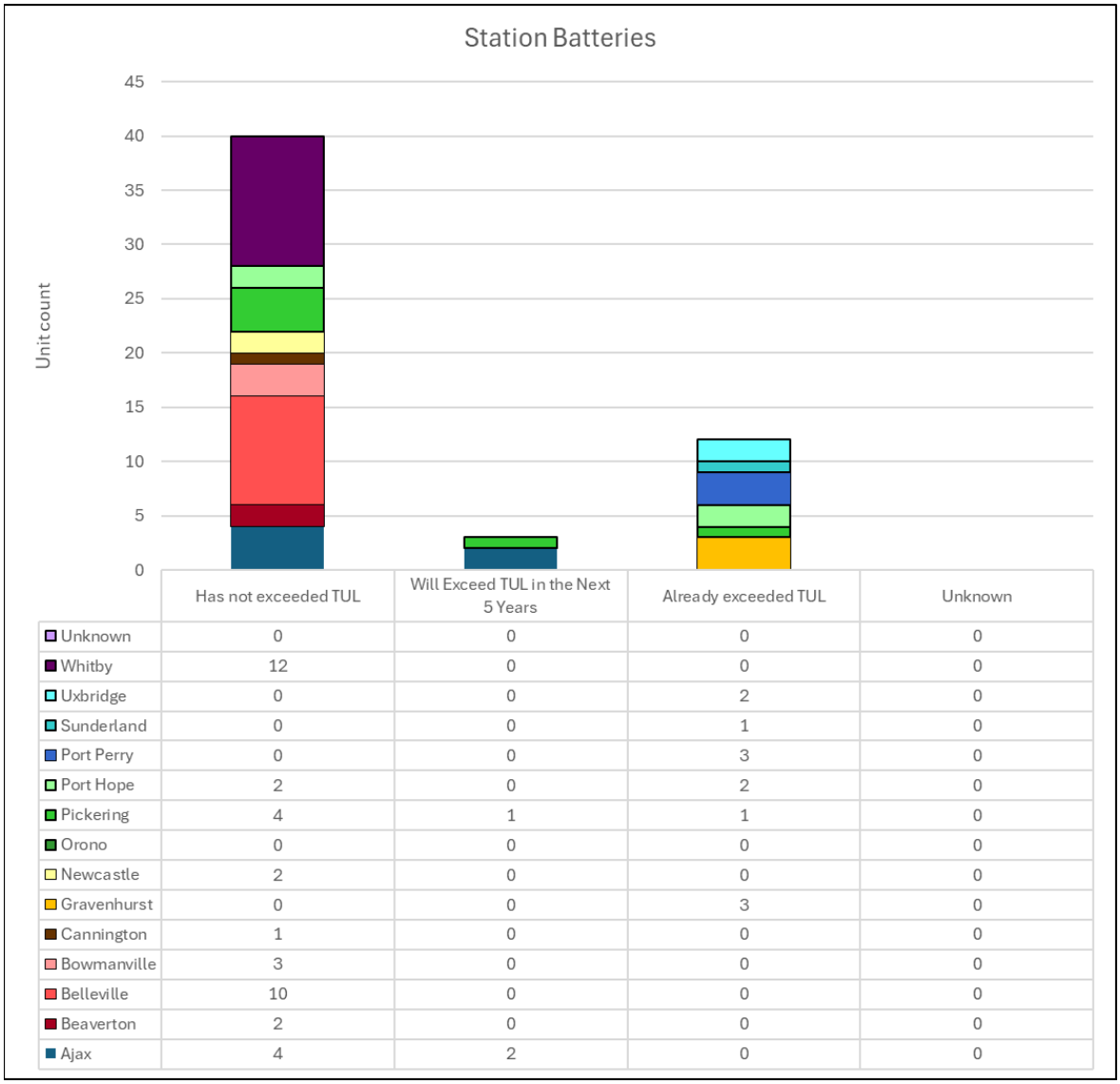
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A, B, C, D, E	4,3,2,1,0	16
Battery Voltage Test	4	A, C, E	4,2,0	16
Charger Condition	2	A, B, C, D, E	4,3,2,1,0	8
Battery Bank Condition	2	A, B, C, D, E	4,2,1,0	8
Total Score				48

4.2.4.2. Data Collection and Assumptions

Condition data for station batteries and chargers are collected through detailed inspection, testing, and maintenance forms. The average DAI for station batteries and chargers is 96% and 100% respectively.

4.2.4.3. Demographics

Elexicon owns 55 station batteries. Figure 50 presents the age distribution for station batteries. The TUL for station batteries is 15 years.

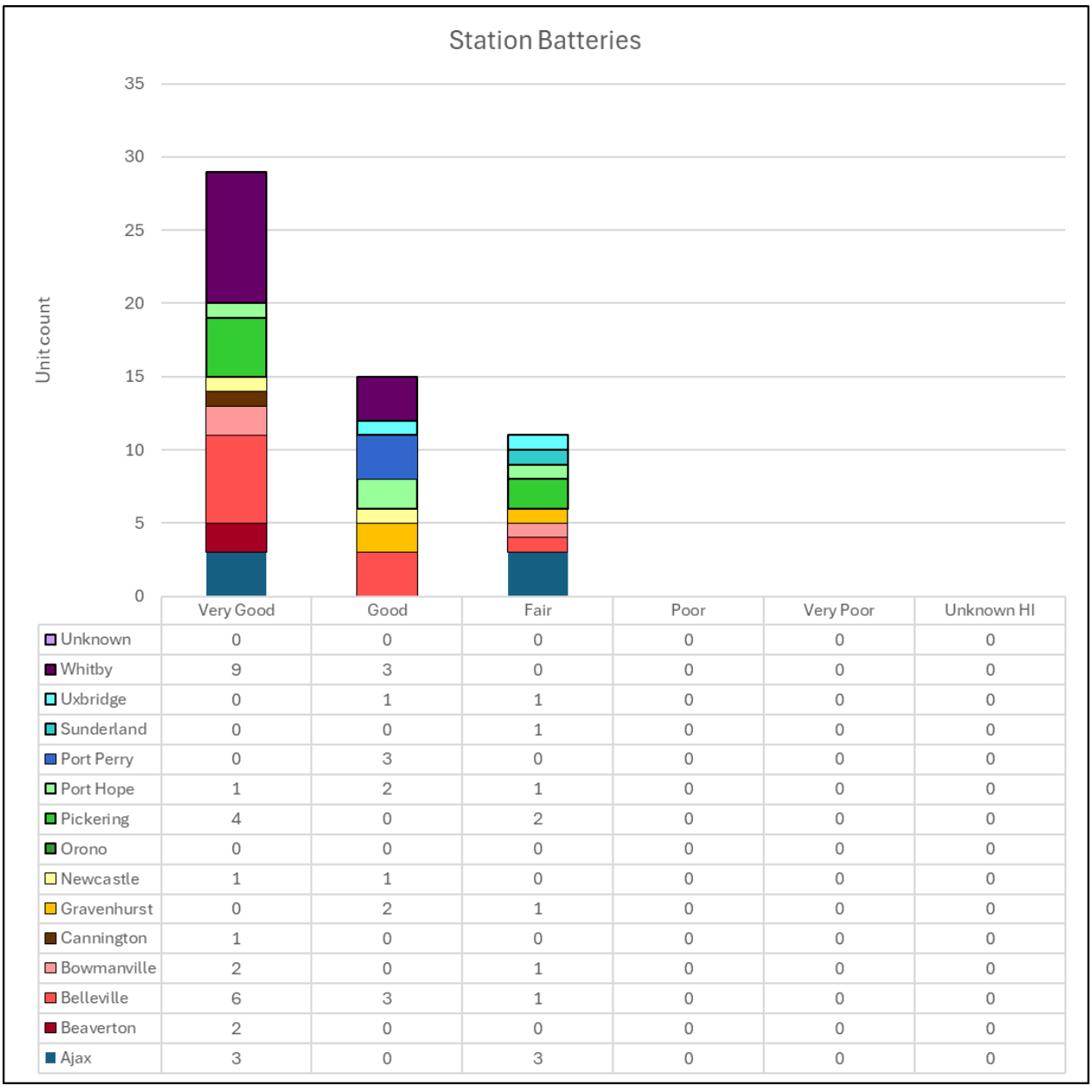


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	12	0	0	0
Uxbridge	0	0	2	0
Sunderland	0	0	1	0
Port Perry	0	0	3	0
Port Hope	2	0	2	0
Pickering	4	1	1	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	0	0	3	0
Cannington	1	0	0	0
Bowmanville	3	0	0	0
Belleville	10	0	0	0
Beaverton	2	0	0	0
Ajax	4	2	0	0

Figure 50: Battery Age Distribution

4.2.4.4. HI Results

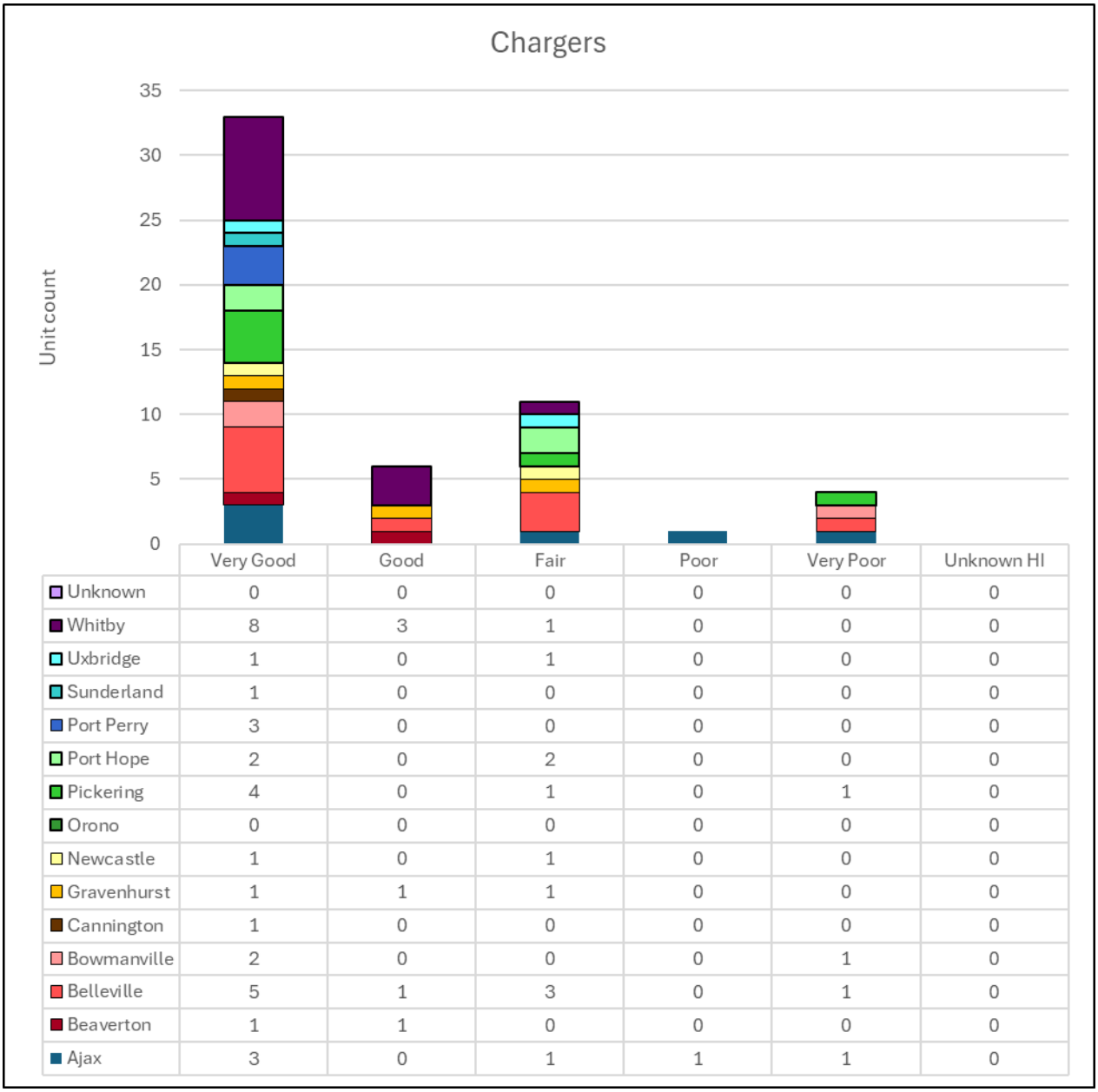
The overall HI distribution for station batteries is presented in Figure 51. Most batteries are in Very Good condition. There are no station batteries in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	9	3	0	0	0	0
Uxbridge	0	1	1	0	0	0
Sunderland	0	0	1	0	0	0
Port Perry	0	3	0	0	0	0
Port Hope	1	2	1	0	0	0
Pickering	4	0	2	0	0	0
Orono	0	0	0	0	0	0
Newcastle	1	1	0	0	0	0
Gravenhurst	0	2	1	0	0	0
Cannington	1	0	0	0	0	0
Bowmanville	2	0	1	0	0	0
Belleville	6	3	1	0	0	0
Beaverton	2	0	0	0	0	0
Ajax	3	0	3	0	0	0

Figure 51: Battery HI Results

The condition assessment for station chargers is presented in Figure 52. Most station chargers are in Very Good condition. There are 5 chargers in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	8	3	1	0	0	0
Uxbridge	1	0	1	0	0	0
Sunderland	1	0	0	0	0	0
Port Perry	3	0	0	0	0	0
Port Hope	2	0	2	0	0	0
Pickering	4	0	1	0	1	0
Orono	0	0	0	0	0	0
Newcastle	1	0	1	0	0	0
Gravenhurst	1	1	1	0	0	0
Cannington	1	0	0	0	0	0
Bowmanville	2	0	0	0	1	0
Belleville	5	1	3	0	1	0
Beaverton	1	1	0	0	0	0
Ajax	3	0	1	1	1	0

Figure 52: Charger Condition Results

4.2.5. Station Relays

4.2.5.1. Condition Assessment Methodology

Station protective relays are an asset used in substation operations to trip a circuit breaker when a fault is detected. Modern relays are typically microprocessor types and include programmable features and communications. Legacy relays are mechanical and require regular calibration; however, most mechanical relays have been replaced with newer models.

Station relays are more likely to become obsolete based on functionality and communication needs rather than physically deteriorating due to environmental conditions. An example of a protective relay is shown below.



Figure 53: Image of Protective Relay

Table 22 below provides the HI algorithm for station relays. Additional details about the condition parameters can be found in Appendix A.17.

Table 22: Station Relay HI Algorithm

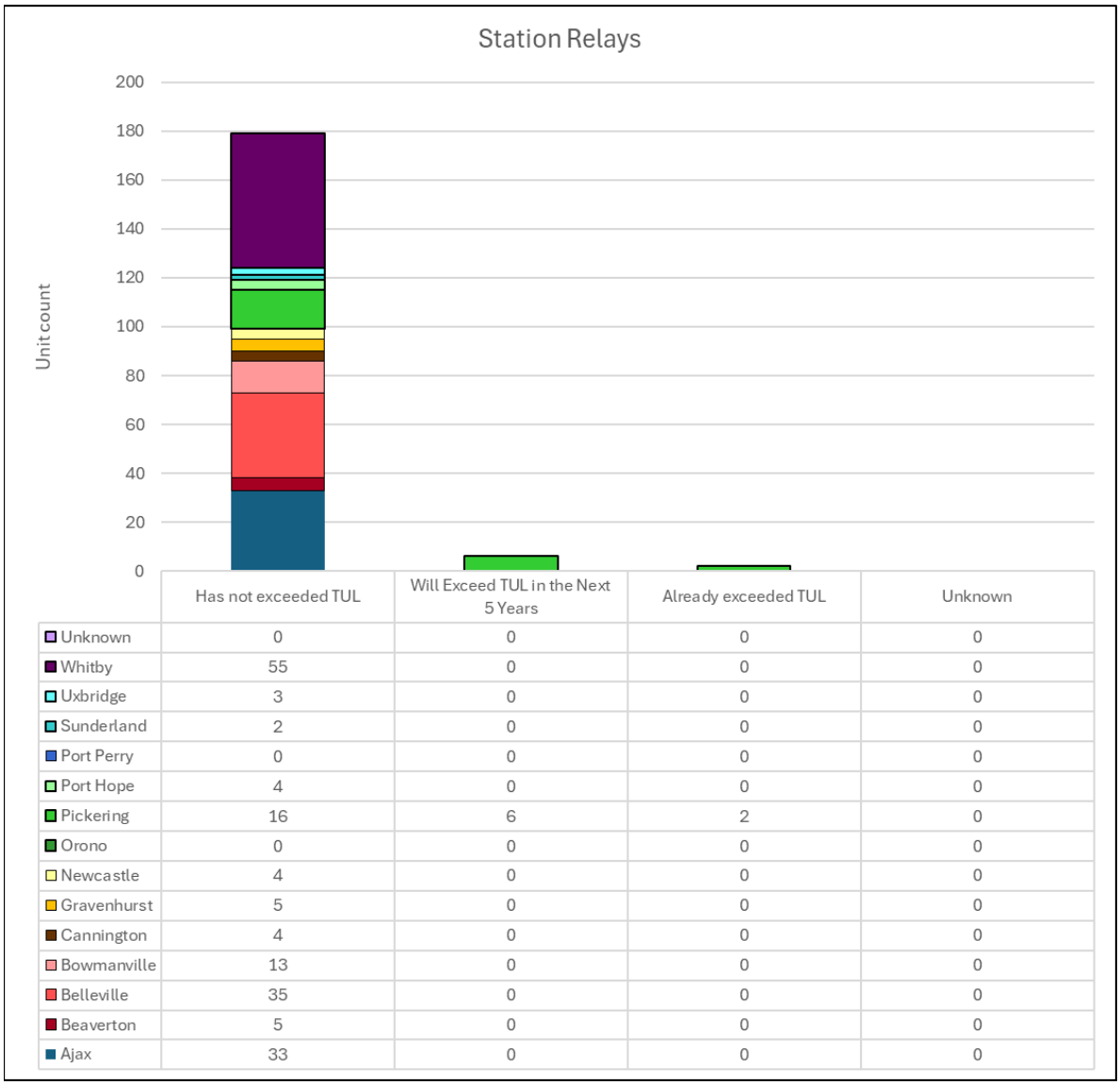
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Test Results	4	A,B,C,D	4,3,2,1	16
Overall Condition	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				44

4.2.5.2. Data Collection and Assumptions

Condition data for station protective relays is collected through detailed inspection, testing, and maintenance forms. The average DAI for station relays is 92%.

4.2.5.3. Demographics

Elexicon owns 187 station relays. Figure 54 presents the age distribution for station relays. The TUL for station relays is 30 years.

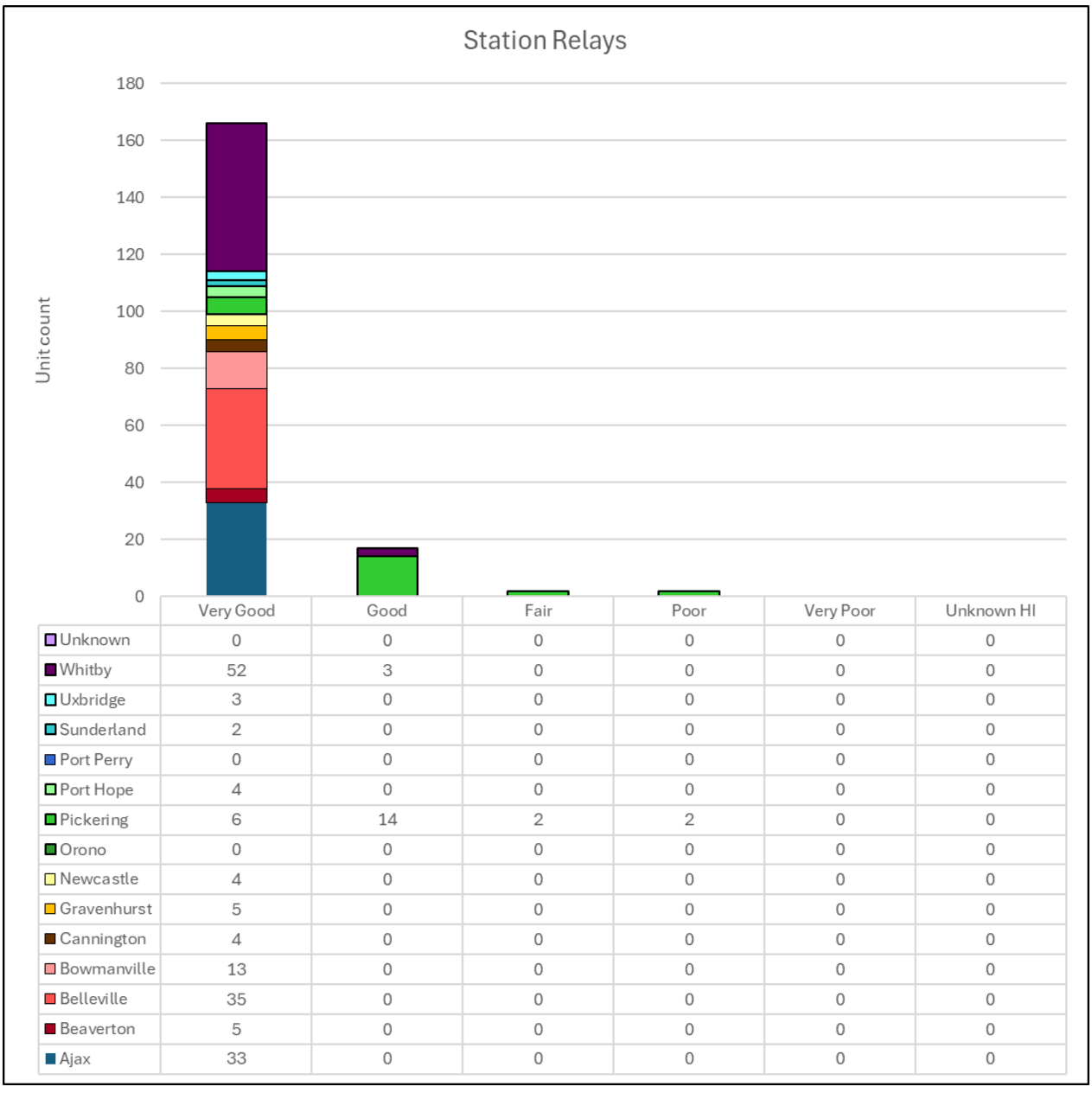


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	55	0	0	0
Uxbridge	3	0	0	0
Sunderland	2	0	0	0
Port Perry	0	0	0	0
Port Hope	4	0	0	0
Pickering	16	6	2	0
Orono	0	0	0	0
Newcastle	4	0	0	0
Gravenhurst	5	0	0	0
Cannington	4	0	0	0
Bowmanville	13	0	0	0
Belleville	35	0	0	0
Beaverton	5	0	0	0
Ajax	33	0	0	0

Figure 54: Protective Relay Age Distribution

4.2.5.4. HI Results

The HI distribution for station relays is presented in Figure 55: Protective Station Relay HI Results. Most station relays are in Very Good condition. There are 2 station relays in Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	52	3	0	0	0	0
Uxbridge	3	0	0	0	0	0
Sunderland	2	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	4	0	0	0	0	0
Pickering	6	14	2	2	0	0
Orono	0	0	0	0	0	0
Newcastle	4	0	0	0	0	0
Gravenhurst	5	0	0	0	0	0
Cannington	4	0	0	0	0	0
Bowmanville	13	0	0	0	0	0
Belleville	35	0	0	0	0	0
Beaverton	5	0	0	0	0	0
Ajax	33	0	0	0	0	0

Figure 55: Protective Station Relay HI Results

4.2.6. Station Cables

4.2.6.1. Condition Assessment Methodology

Station cables are the first length of cable out of the station, before the first riser pole. They carry the entire load of each feeder. An example of station cables is shown below.



Figure 56: Image of Station Cables

Table 23 below provides the HI algorithm for station cables. Additional details about the condition parameters can be found in Appendix A.18.

Table 23: Station Cables HI Algorithm

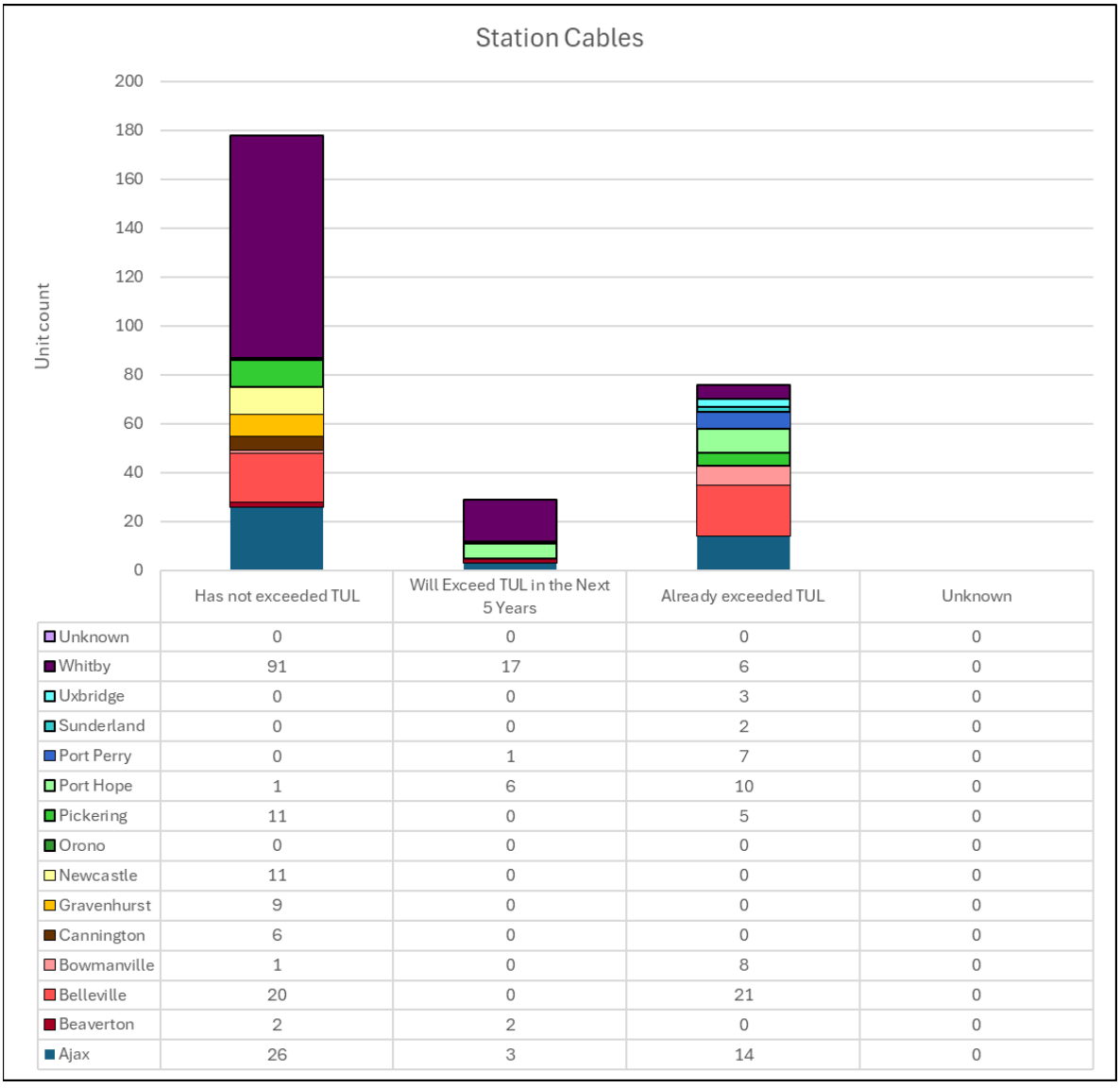
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Insulation Resistance	2	A,B,C,D,E	4,3,2,1,0	8
Loading History	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				20

4.2.6.2. Data Collection and Assumptions

Condition data for station cables is collected through detailed inspection, testing, and maintenance forms. Wire length was not provided for station cables. The average DAI for station cables is 88%.

4.2.6.3. Demographics

Elexicon owns 283 in-service station cables. Figure 57 presents the age distribution for station cables by cable segment. The TUL for station cables is 25 years.

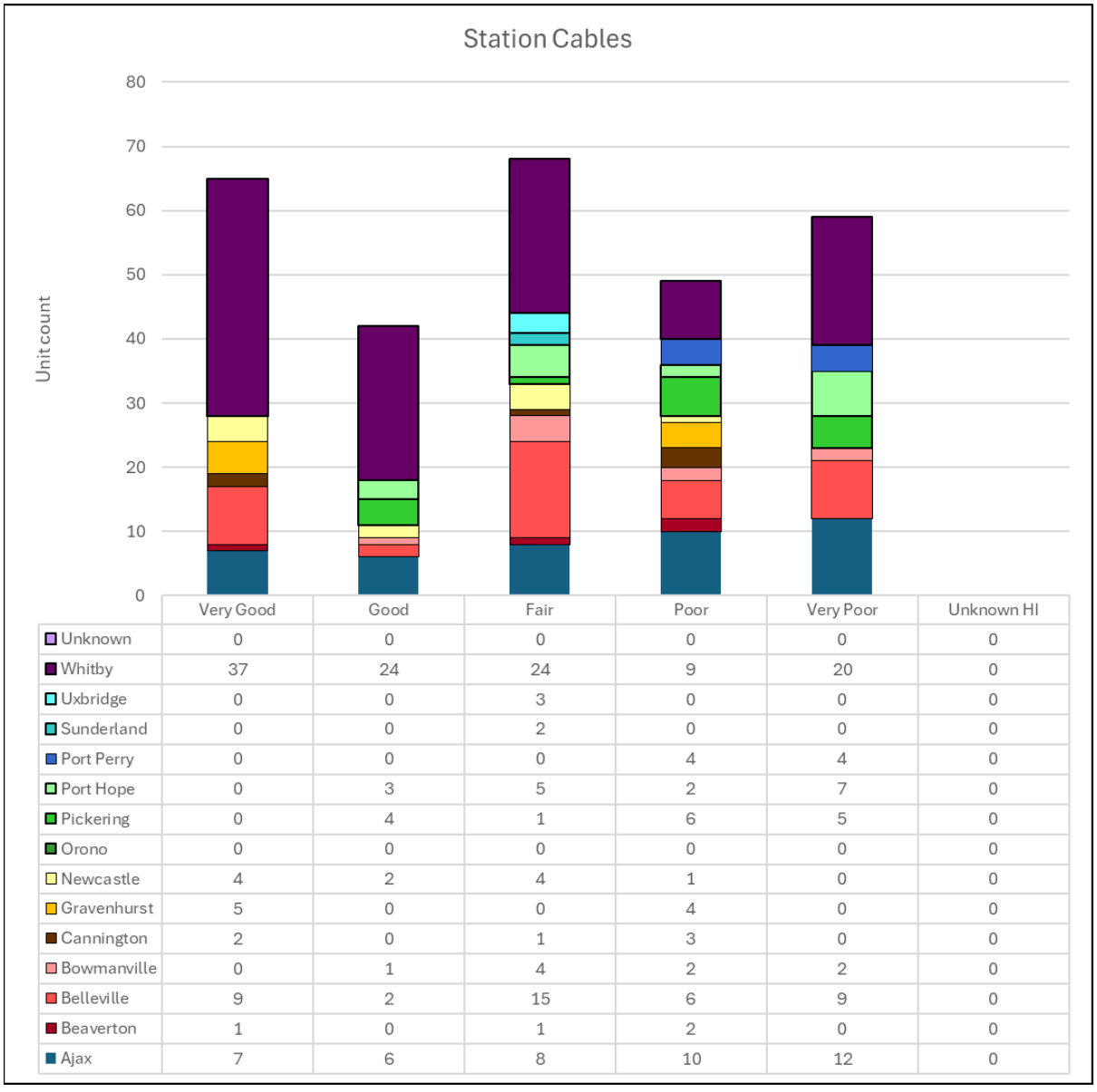


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	91	17	6	0
Uxbridge	0	0	3	0
Sunderland	0	0	2	0
Port Perry	0	1	7	0
Port Hope	1	6	10	0
Pickering	11	0	5	0
Orono	0	0	0	0
Newcastle	11	0	0	0
Gravenhurst	9	0	0	0
Cannington	6	0	0	0
Bowmanville	1	0	8	0
Belleville	20	0	21	0
Beaverton	2	2	0	0
Ajax	26	3	14	0

Figure 57: Station Cable Age Distribution

4.2.6.4. HI Results

The overall HI distribution for station cables presented in Figure 58: Station Cable HI Results by cable segment. Most cables segments are in Very Good to Fair condition. There are 108 station cable segments in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	37	24	24	9	20	0
Uxbridge	0	0	3	0	0	0
Sunderland	0	0	2	0	0	0
Port Perry	0	0	0	4	4	0
Port Hope	0	3	5	2	7	0
Pickering	0	4	1	6	5	0
Orono	0	0	0	0	0	0
Newcastle	4	2	4	1	0	0
Gravenhurst	5	0	0	4	0	0
Cannington	2	0	1	3	0	0
Bowmanville	0	1	4	2	2	0
Belleville	9	2	15	6	9	0
Beaverton	1	0	1	2	0	0
Ajax	7	6	8	10	12	0

Figure 58: Station Cable HI Results

4.2.7. Station Buildings

4.2.7.1. Condition Assessment Methodology

Station buildings, which refer to the walls, roof, floors, doors etc. of the station are the major civil infrastructure components of a utility substation. Other civil infrastructure systems supporting a station may include support structures, security equipment, laneways, lighting equipment, plumbing systems, and others.

Buildings are inspected monthly and are maintained as issues arise. In some cases, buildings can be scheduled for replacement, especially where configurations of the station are inadequate or where projects exist to replace the entirety of the relay and switchgear lineups. Generally, however, buildings are patched up as needed to remain functional. As such service age was not considered in the HIF. An example of a station building is shown below.



Figure 59: Image of Station Building

Table 24 below provides the HI algorithm for station buildings. Additional details about these condition parameters can be found in Appendix A.19.

Table 24: Station Building HI Algorithm

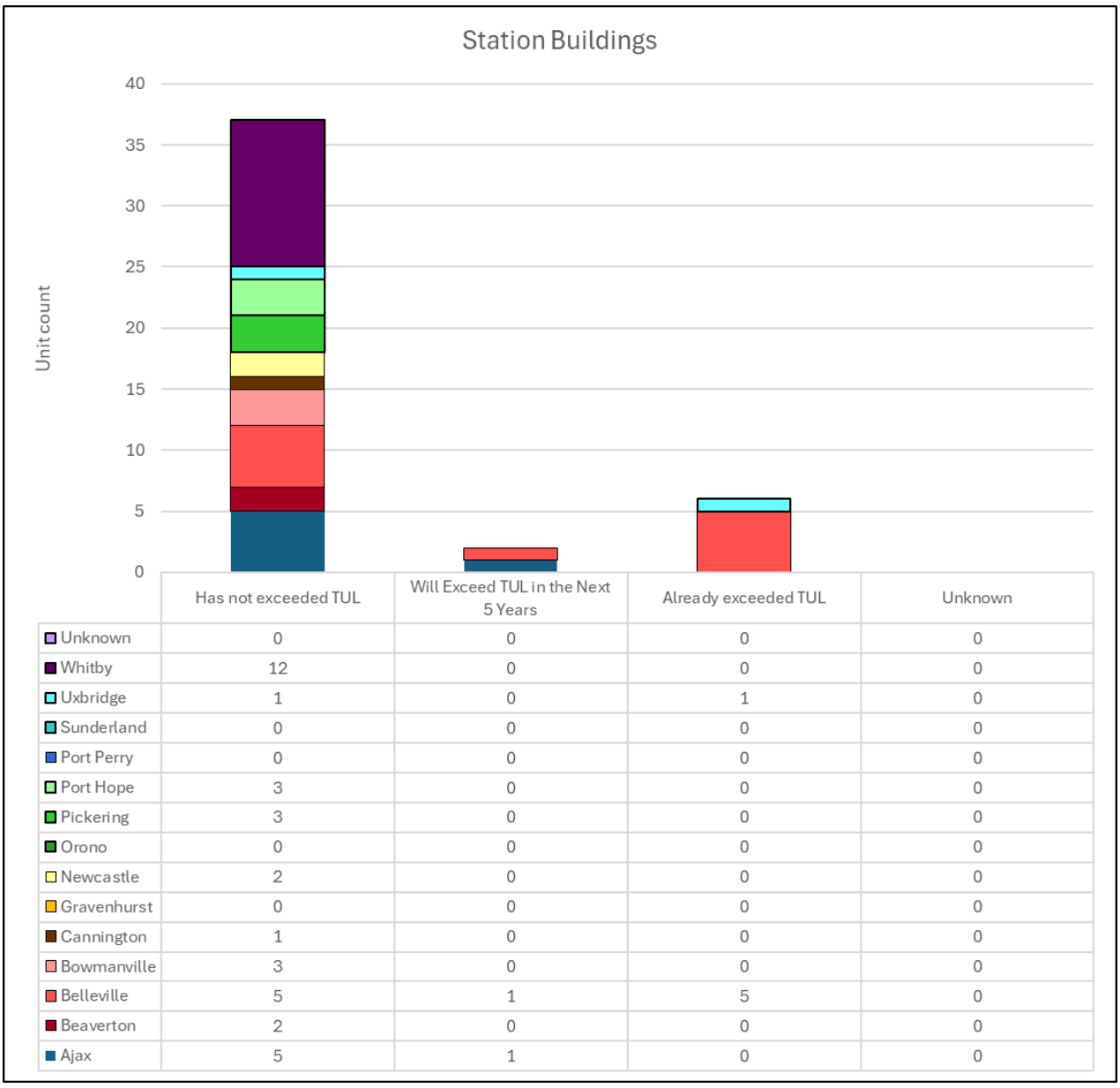
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Paint Condition	3	A,C,E	4,2,0	12
Presence of Leaks	3	A,C,E	4,2,0	12
Presence of Floor Debris	3	A,C,E	4,2,0	12
Condition of Basement/Cable Pit	3	A,C,E	4,2,0	12
Doors, Locks and Windows Condition	2	A,C,E	4,2,0	8
Condition of Heating and Air Conditioning	2	A,C,E	4,2,0	8
Condition of Shutters and Ventilation	1	A,C,E	4,2,0	4
Condition of Exhaust Fan	1	A,C,E	4,2,0	4
Condition of Fire Extinguisher	1	A,C,E	4,2,0	4
Condition of Eye Wash Station	1	A,C,E	4,2,0	4
Total Score				80

4.2.7.2. Data Collection and Assumptions

Condition data for station buildings is collected through detailed inspection and maintenance forms. The average DAI for station buildings is 99%.

4.2.7.3. Demographics

Elexicon owns 45 station buildings. Figure 60 presents the age distribution for in-service station buildings. The TUL for station buildings in 60 years.

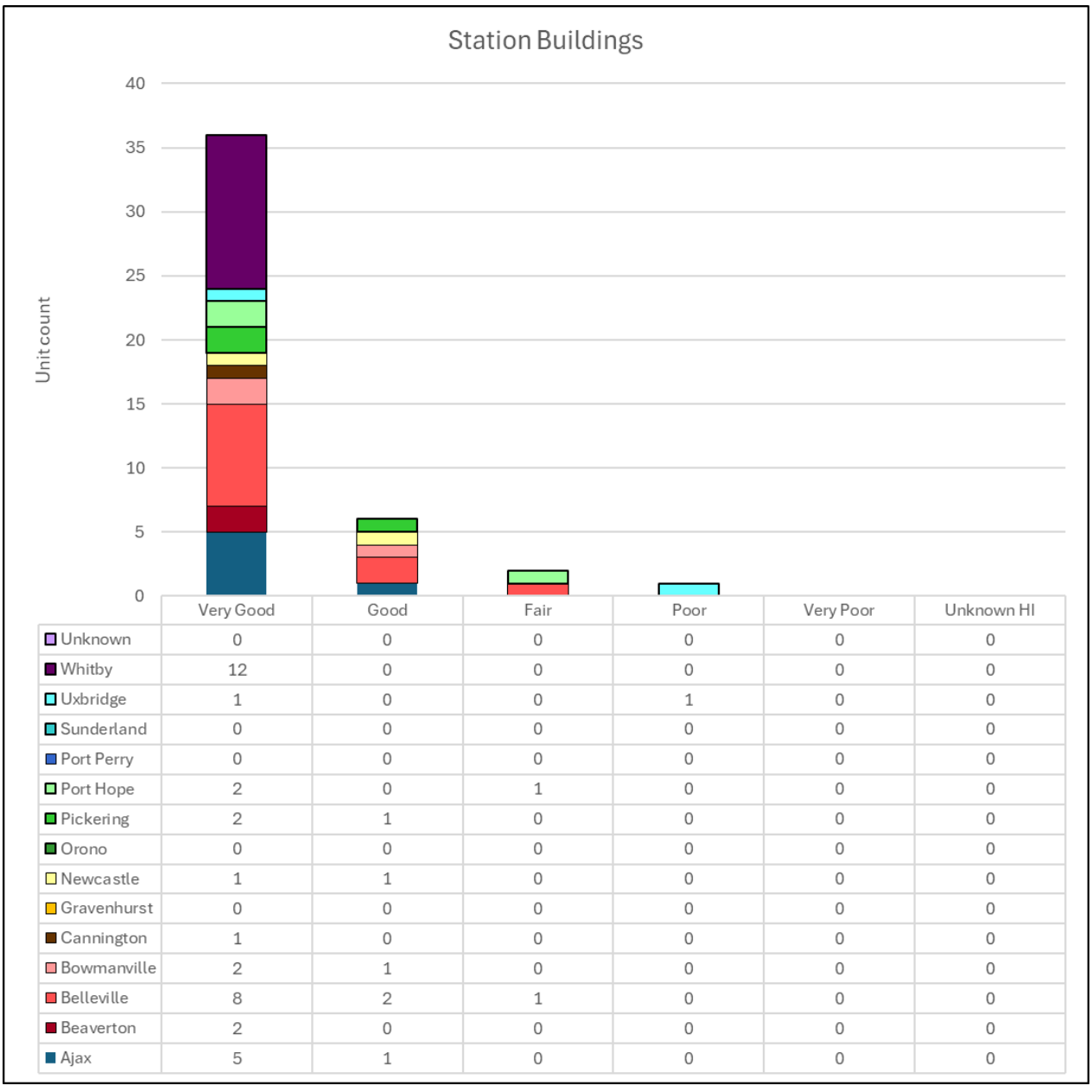


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	12	0	0	0
Uxbridge	1	0	1	0
Sunderland	0	0	0	0
Port Perry	0	0	0	0
Port Hope	3	0	0	0
Pickering	3	0	0	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	0	0	0	0
Cannington	1	0	0	0
Bowmanville	3	0	0	0
Belleville	5	1	5	0
Beaverton	2	0	0	0
Ajax	5	1	0	0

Figure 60: Station Building Age Distribution

4.2.7.4. HI Results

The HI distribution of station buildings is presented in Figure 61. Most station buildings are in Very Good condition. There is one station building in Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	12	0	0	0	0	0
Uxbridge	1	0	0	1	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	0	0	0
Port Hope	2	0	1	0	0	0
Pickering	2	1	0	0	0	0
Orono	0	0	0	0	0	0
Newcastle	1	1	0	0	0	0
Gravenhurst	0	0	0	0	0	0
Cannington	1	0	0	0	0	0
Bowmanville	2	1	0	0	0	0
Belleville	8	2	1	0	0	0
Beaverton	2	0	0	0	0	0
Ajax	5	1	0	0	0	0

Figure 61: Station Building HI Results

4.2.8. Station Fences

4.2.8.1. Condition Assessment Methodology

Station fences are also part of the major civil infrastructure components of a utility substation. Fences are inspected monthly and are maintained as issues arise. In some cases, they can be scheduled for replacement, especially where configurations of the station are inadequate or where projects exist to replace the entirety of the relay and switchgear lineups. Generally, however, fences are maintained and gates are repaired as needed to remain functional. As such service age was not considered in the HIF. An example of a station fence is shown below.



Figure 62: Image of Station Fence

Table 25 below provides the HI algorithm for station fences. Additional details about these condition parameters can be found in Appendix A.20.

Table 25: Station Fence HI Algorithm

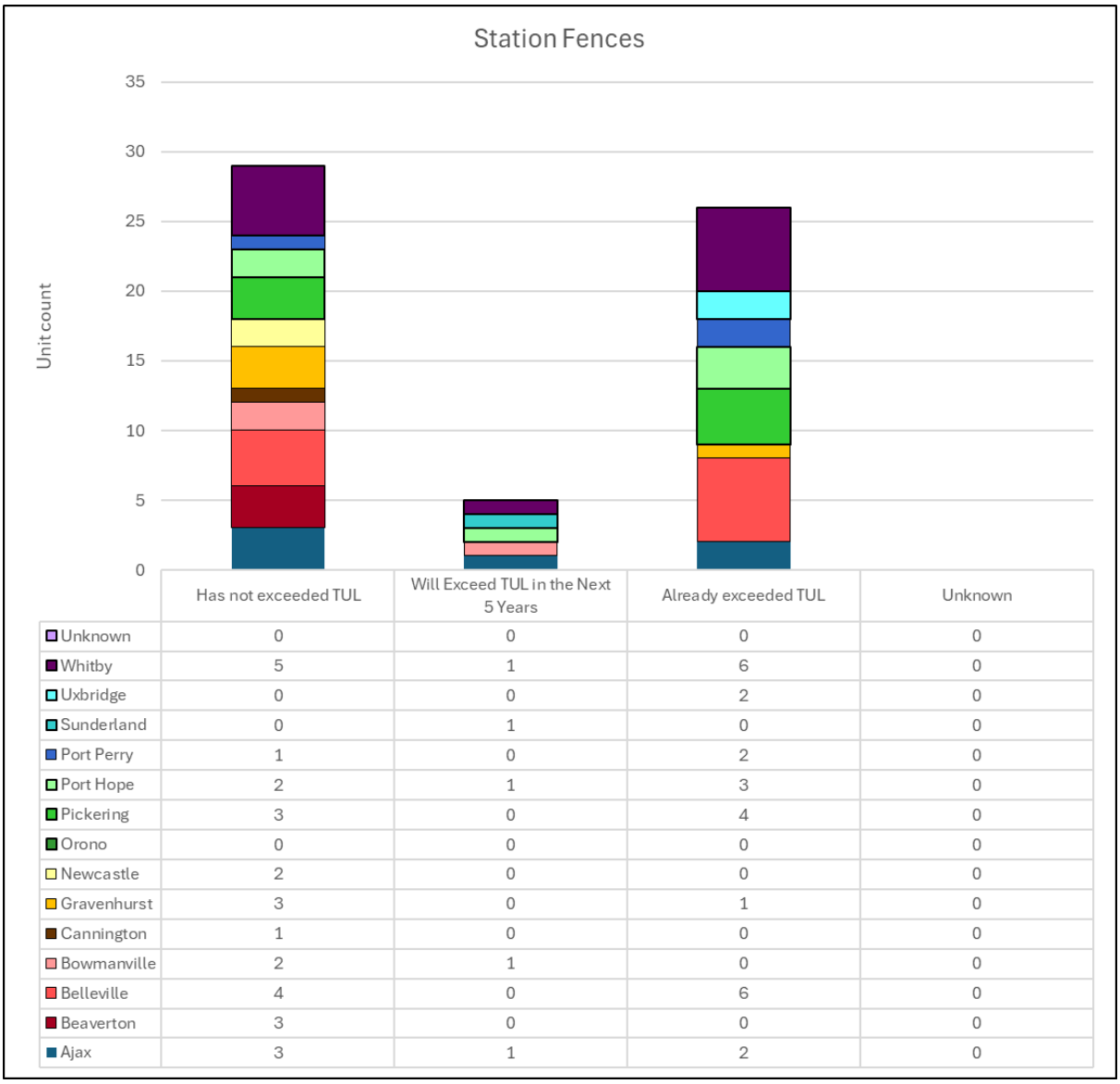
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Fence Condition	2	A,C,E	4,2,0	8
Barbed Wire Condition	1	A,C,E	4,2,0	4
Gate Condition	1	A,C,E	4,2,0	4
Fence Grounding Condition	1	A,C,E	4,2,0	4
Total Score				20

4.2.8.2. Data Collection and Assumptions

Condition data for station fences is collected through detailed inspection and maintenance forms. The average DAI for station fences is 100%.

4.2.8.3. Demographics

Elexicon owns 60 station fences. Figure 63 presents the age distribution for station fences. The TUL for station fences is 40 years.

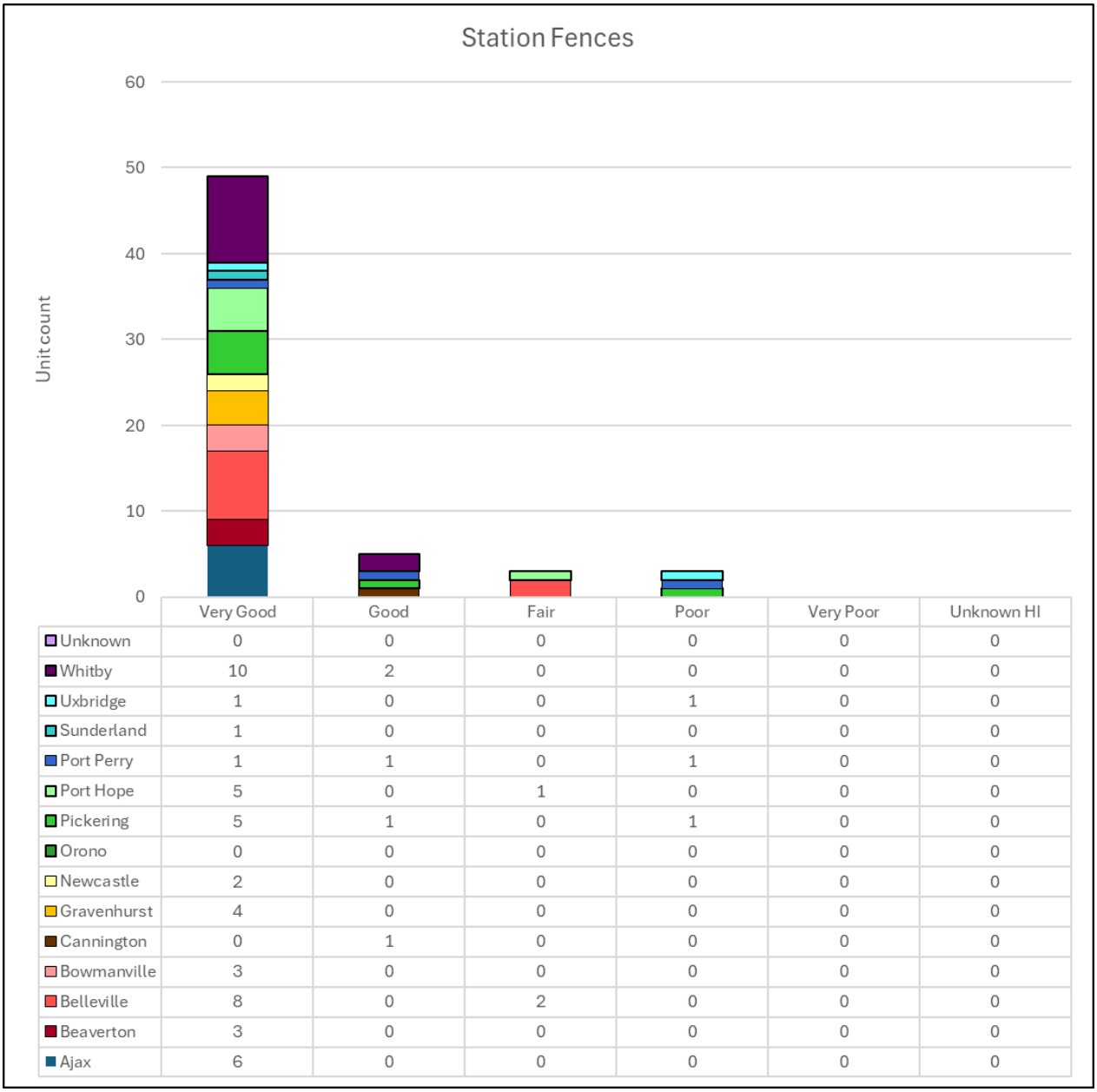


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	5	1	6	0
Uxbridge	0	0	2	0
Sunderland	0	1	0	0
Port Perry	1	0	2	0
Port Hope	2	1	3	0
Pickering	3	0	4	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	3	0	1	0
Cannington	1	0	0	0
Bowmanville	2	1	0	0
Belleville	4	0	6	0
Beaverton	3	0	0	0
Ajax	3	1	2	0

Figure 63: Fence Age Distribution

4.2.8.4. HI Results

The HI distribution for station fences is presented in Figure 64. Most station fences are in Very Good condition. There are 3 station fences in Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	10	2	0	0	0	0
Uxbridge	1	0	0	1	0	0
Sunderland	1	0	0	0	0	0
Port Perry	1	1	0	1	0	0
Port Hope	5	0	1	0	0	0
Pickering	5	1	0	1	0	0
Orono	0	0	0	0	0	0
Newcastle	2	0	0	0	0	0
Gravenhurst	4	0	0	0	0	0
Cannington	0	1	0	0	0	0
Bowmanville	3	0	0	0	0	0
Belleville	8	0	2	0	0	0
Beaverton	3	0	0	0	0	0
Ajax	6	0	0	0	0	0

Figure 64: Fence HI Results

4.2.9. Station Switchgears

4.2.9.1. Condition Assessment Methodology

Station switchgears consist of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the primary switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. An image of a station switchgear is shown below. Switchgear degradation occurs primarily through physical processes, such as corrosion, accumulation of debris, or operations under load.



Figure 65: Image of Station Switchgear

Table 26 below provides the HI algorithm for station switchgears. Additional details about the condition parameters can be found in Appendix A.21.

Table 26: Station Switchgears HI Algorithm

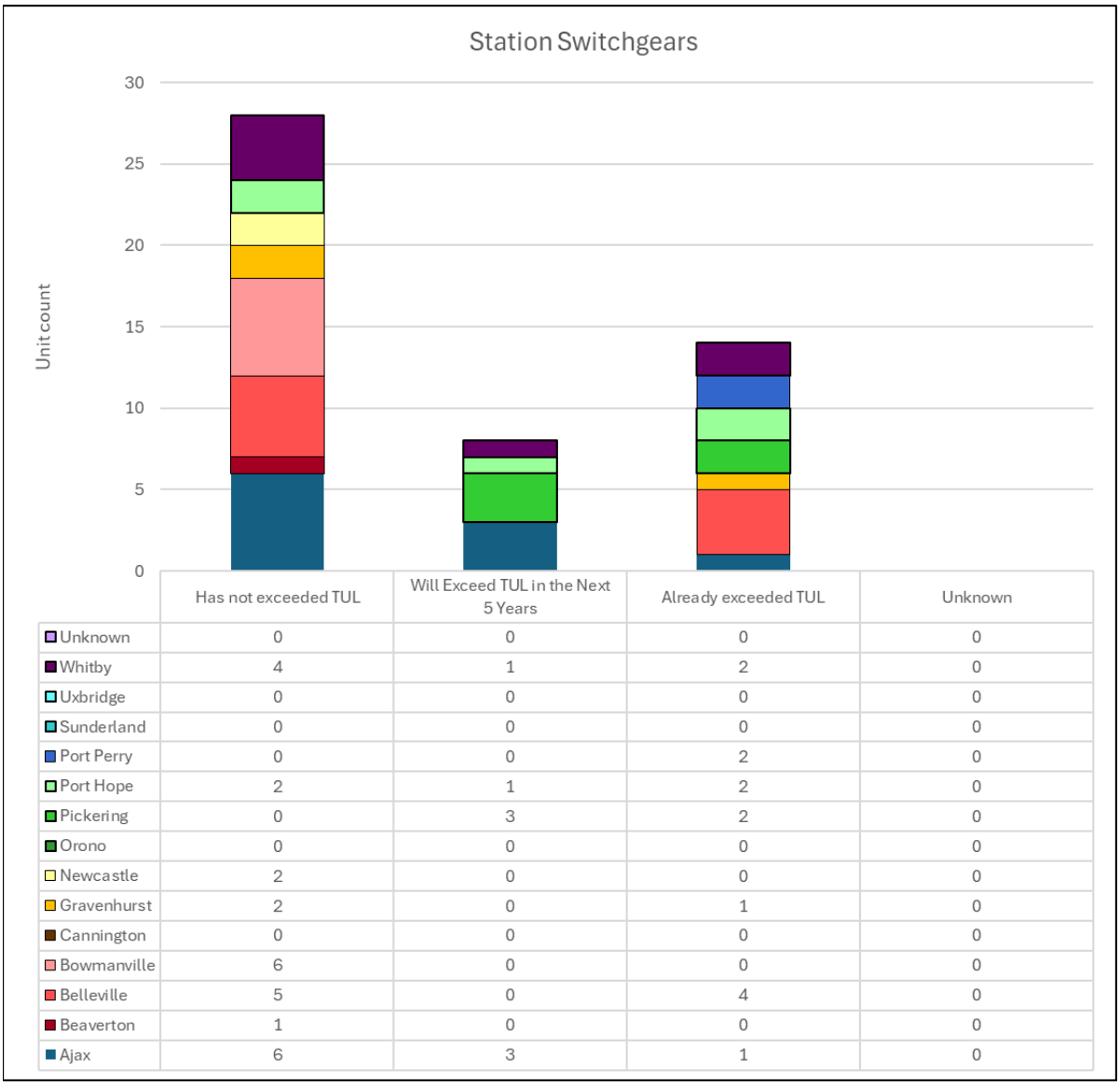
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance Test	6	A,B,C,D,E	4,3,2,1,0	24
Presence of Moisture	4	A,C,E	4,2,0	16
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Mechanical Integrity	2	A,C,E	4,2,0	8
Condition of Pad	1	A,C	4,2	4
Paint	1	A,C,E	4,2,0	4
Total Score				64

4.2.9.2. Data Collection and Assumptions

Condition and testing data for station switchgears is collected through detailed inspection, testing, and maintenance forms. The average DAI for station switchgears is 98%.

4.2.9.3. Demographics

Data was provided for 50 in-service station switchgears. Figure 66 presents the age distribution for in-service station switchgears. The TUL for station switchgears is 40 years.

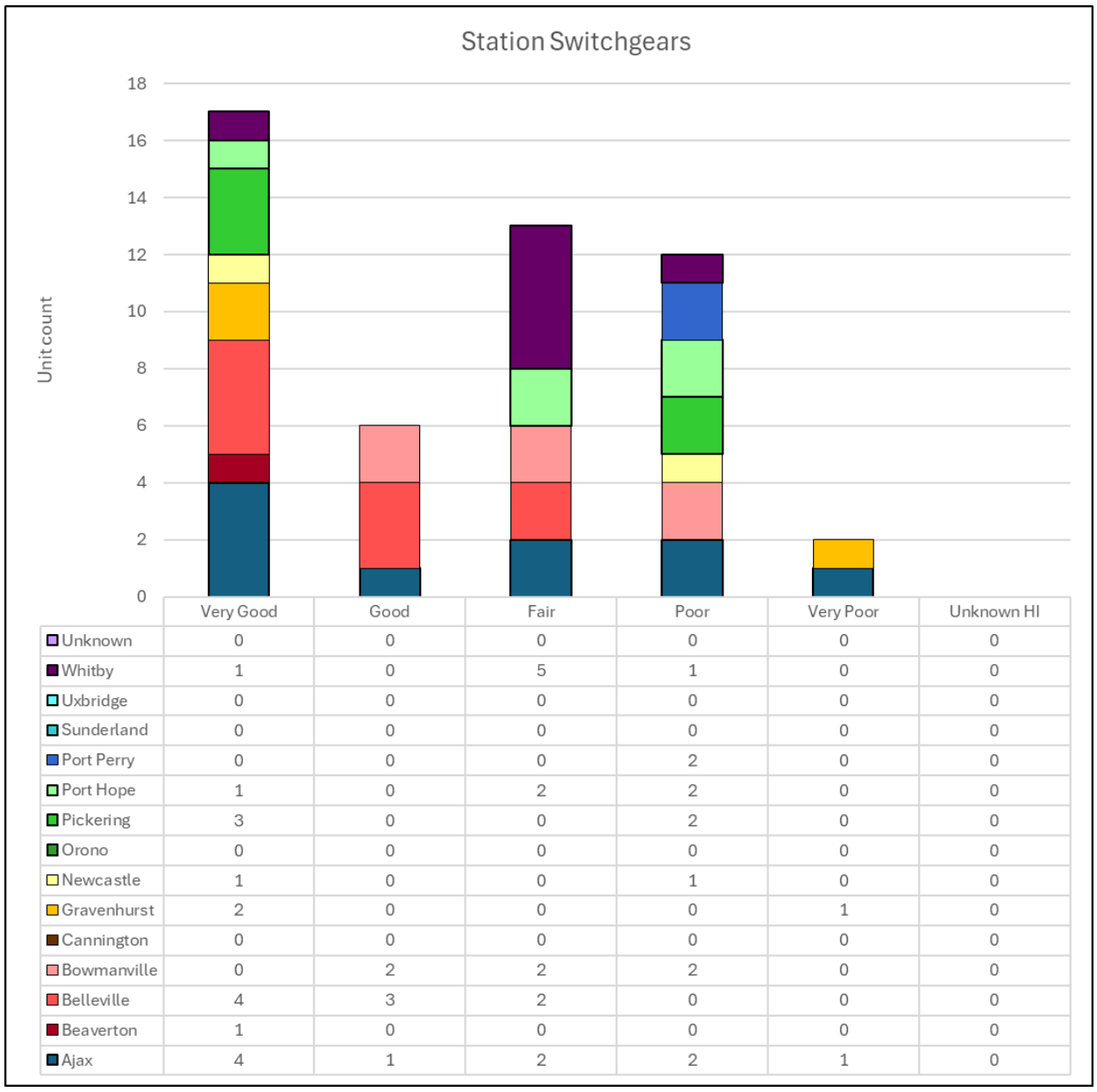


	Has not exceeded TUL	Will Exceed TUL in the Next 5 Years	Already exceeded TUL	Unknown
Unknown	0	0	0	0
Whitby	4	1	2	0
Uxbridge	0	0	0	0
Sunderland	0	0	0	0
Port Perry	0	0	2	0
Port Hope	2	1	2	0
Pickering	0	3	2	0
Orono	0	0	0	0
Newcastle	2	0	0	0
Gravenhurst	2	0	1	0
Cannington	0	0	0	0
Bowmanville	6	0	0	0
Belleville	5	0	4	0
Beaverton	1	0	0	0
Ajax	6	3	1	0

Figure 66: Station Switchgear Age Distribution

4.2.9.4. HI Results

The HI distribution of station switchgears is shown in Figure 67. Most station switchgears are in Very Good to Fair condition. There are 14 station switchgears in Poor and Very Poor condition.



	Very Good	Good	Fair	Poor	Very Poor	Unknown HI
Unknown	0	0	0	0	0	0
Whitby	1	0	5	1	0	0
Uxbridge	0	0	0	0	0	0
Sunderland	0	0	0	0	0	0
Port Perry	0	0	0	2	0	0
Port Hope	1	0	2	2	0	0
Pickering	3	0	0	2	0	0
Orono	0	0	0	0	0	0
Newcastle	1	0	0	1	0	0
Gravenhurst	2	0	0	0	1	0
Cannington	0	0	0	0	0	0
Bowmanville	0	2	2	2	0	0
Belleville	4	3	2	0	0	0
Beaverton	1	0	0	0	0	0
Ajax	4	1	2	2	1	0

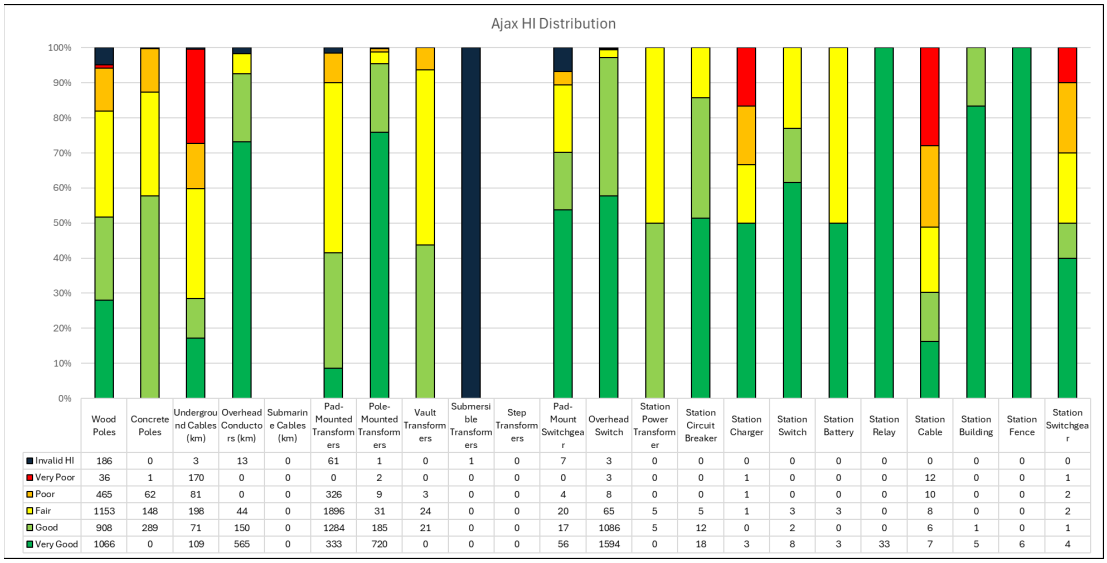
Figure 67: Station Switchgear HI Results

4.3. Asset Condition Assessment Results by Service Area

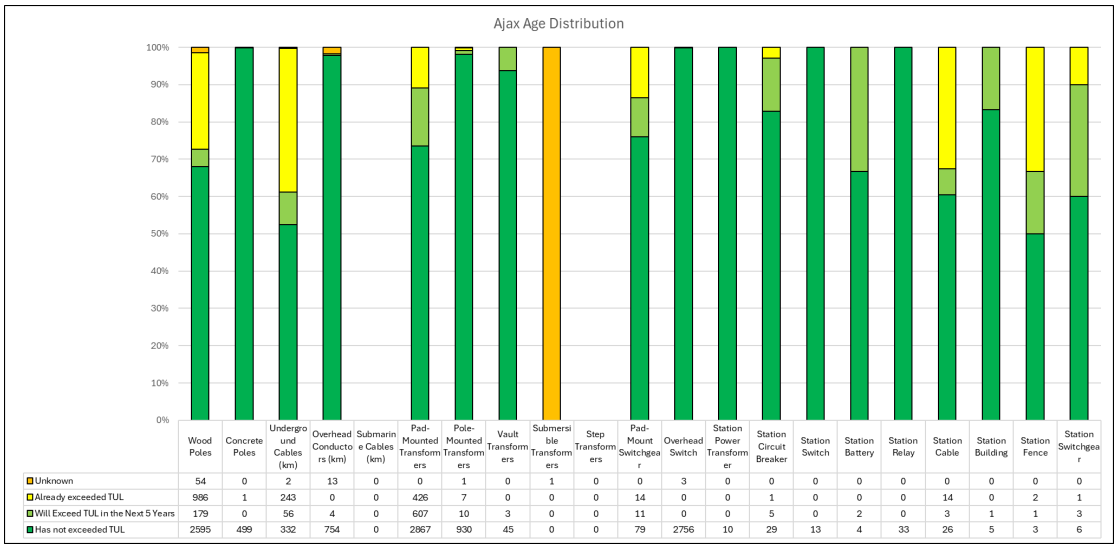
Figure 68 to Figure 81 provide a breakdown of the results by service area for all asset classes.

4.3.1. Ajax

The figures below present the HI results and age distribution in Ajax.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	186	0	3	13	0	61	1	0	1	0	7	3	0	0	0	0	0	0	0	0	0	0
Very Poor	36	1	170	0	0	0	2	0	0	0	0	3	0	0	1	0	0	0	12	0	0	1
Poor	465	62	81	0	0	326	9	3	0	0	4	8	0	0	1	0	0	0	10	0	0	2
Fair	1153	148	198	44	0	1896	31	24	0	0	20	65	5	5	1	3	3	0	8	0	0	2
Good	908	289	71	150	0	1284	185	21	0	0	17	1086	5	12	0	2	0	0	6	1	0	1
Very Good	1066	0	109	565	0	333	720	0	0	0	56	1594	0	18	3	8	3	33	7	5	6	4

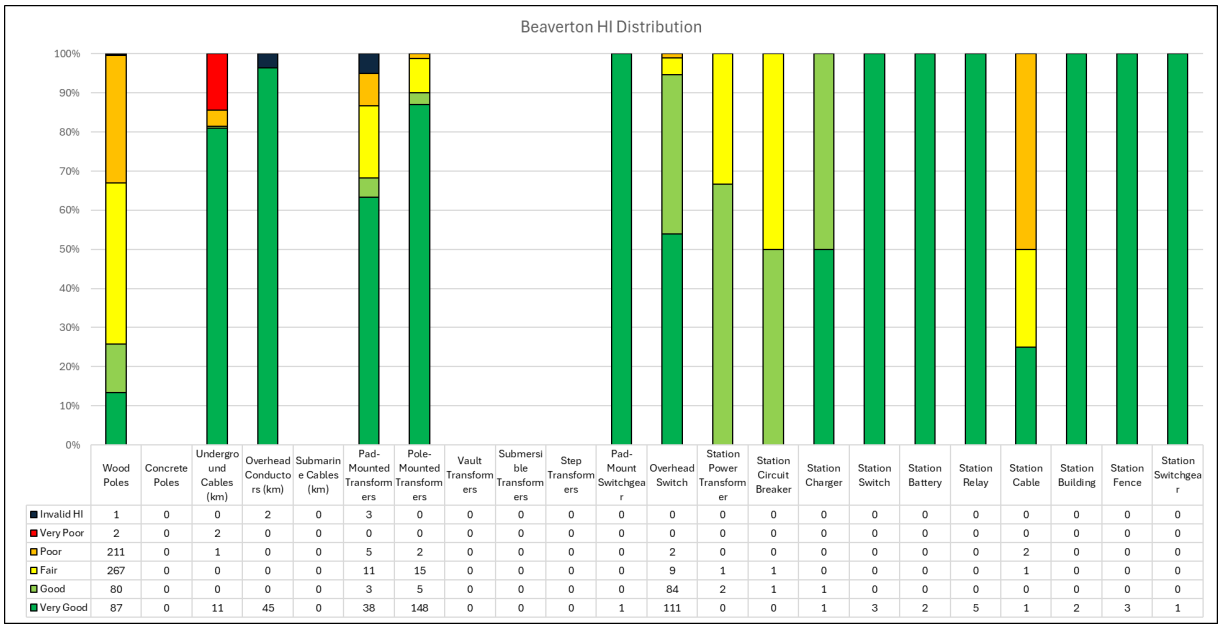


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	54	0	2	13	0	0	1	0	1	0	0	3	0	0	0	0	0	0	0	0	0
Already exceeded TUL	986	1	243	0	0	426	7	0	0	0	14	0	0	1	0	0	0	14	0	2	1
Will Exceed TUL in the Next 5 Years	179	0	56	4	0	607	10	3	0	0	11	0	0	5	0	2	0	3	1	1	3
Has not exceeded TUL	2595	499	332	754	0	2867	930	45	0	0	79	2756	10	29	13	4	33	26	5	3	6

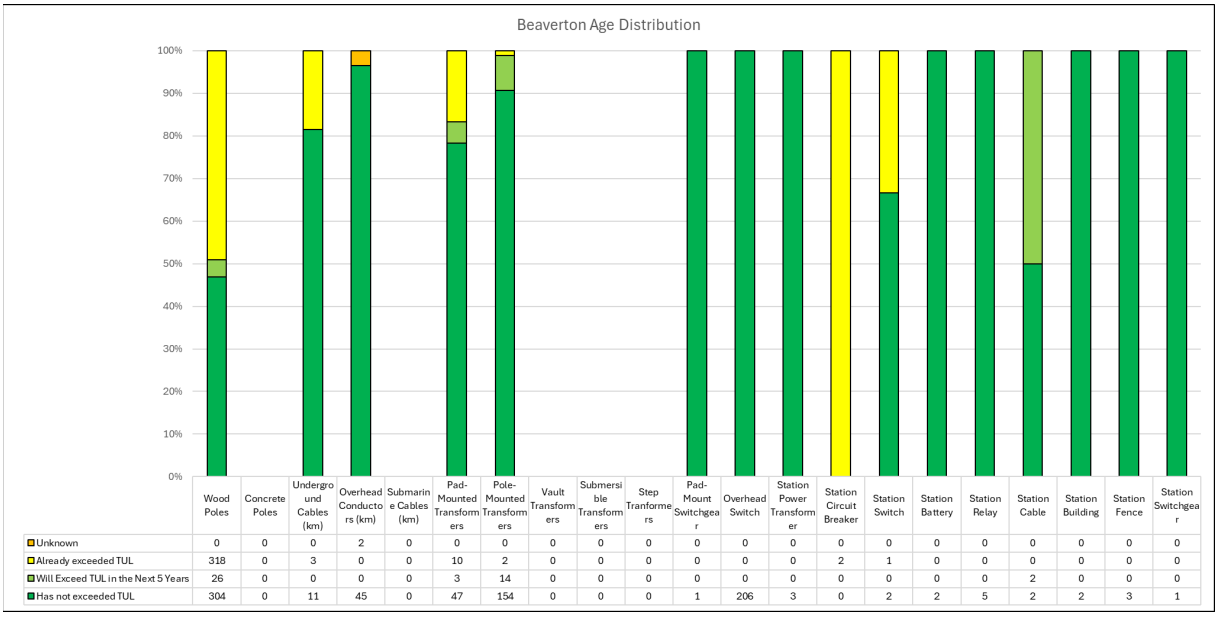
Figure 68: Ajax HI Results and Age Distribution

4.3.2. Beaverton

The figures below present the HI results and age distribution in Beaverton.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	1	0	0	2	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Very Poor	2	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poor	211	0	1	0	0	5	2	0	0	0	0	2	0	0	0	0	0	0	2	0	0	0
Fair	267	0	0	0	0	11	15	0	0	0	0	9	1	1	0	0	0	0	1	0	0	0
Good	80	0	0	0	0	3	5	0	0	0	0	84	2	1	1	0	0	0	0	0	0	0
Very Good	87	0	11	45	0	38	148	0	0	0	1	111	0	0	1	3	2	5	1	2	3	1

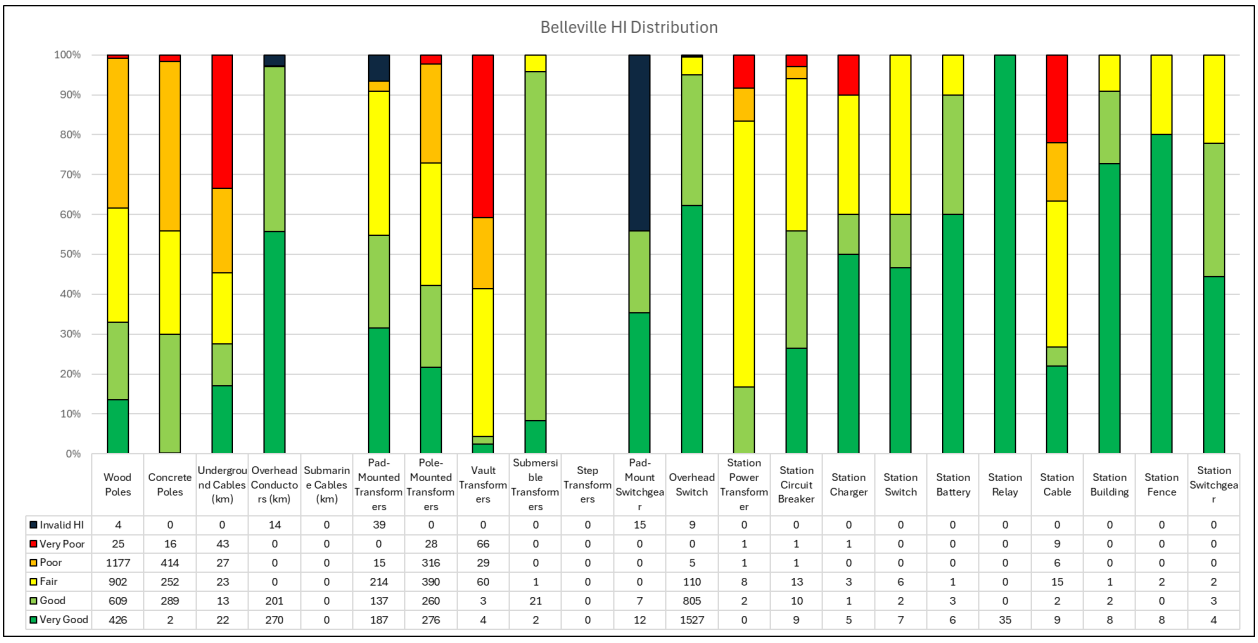


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Tranformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	318	0	3	0	0	10	2	0	0	0	0	0	0	2	1	0	0	0	0	0	0
Will Exceed TUL in the Next 5 Years	26	0	0	0	0	3	14	0	0	0	0	0	0	0	0	0	0	2	0	0	0
Has not exceeded TUL	304	0	11	45	0	47	154	0	0	0	1	206	3	0	2	2	5	2	2	3	1

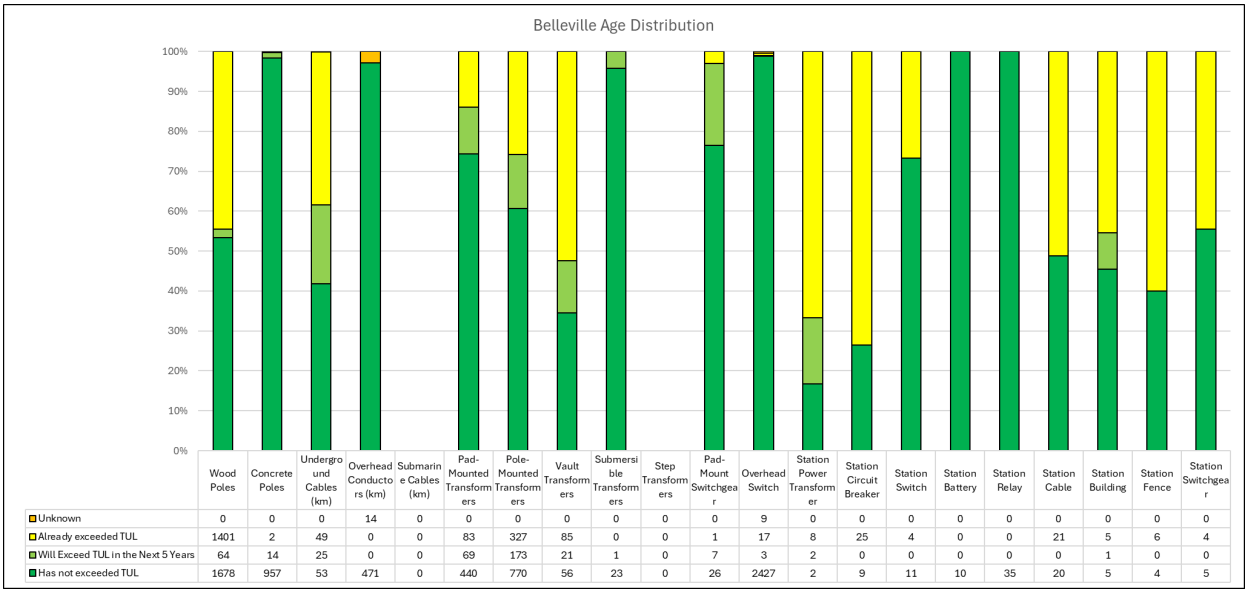
Figure 69: Beaverton HI Results and Age Distribution

4.3.3. Belleville

The figures below present the HI results and age distribution in Belleville.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	4	0	0	14	0	39	0	0	0	0	15	9	0	0	0	0	0	0	0	0	0	0
Very Poor	25	16	43	0	0	0	28	66	0	0	0	0	1	1	1	0	0	0	9	0	0	0
Poor	1177	414	27	0	0	15	316	29	0	0	0	5	1	1	0	0	0	0	6	0	0	0
Fair	902	252	23	0	0	214	390	60	1	0	0	110	8	13	3	6	1	0	15	1	2	2
Good	609	289	13	201	0	137	260	3	21	0	7	805	2	10	1	2	3	0	2	2	0	3
Very Good	426	2	22	270	0	187	276	4	2	0	12	1527	0	9	5	7	6	35	9	8	8	4

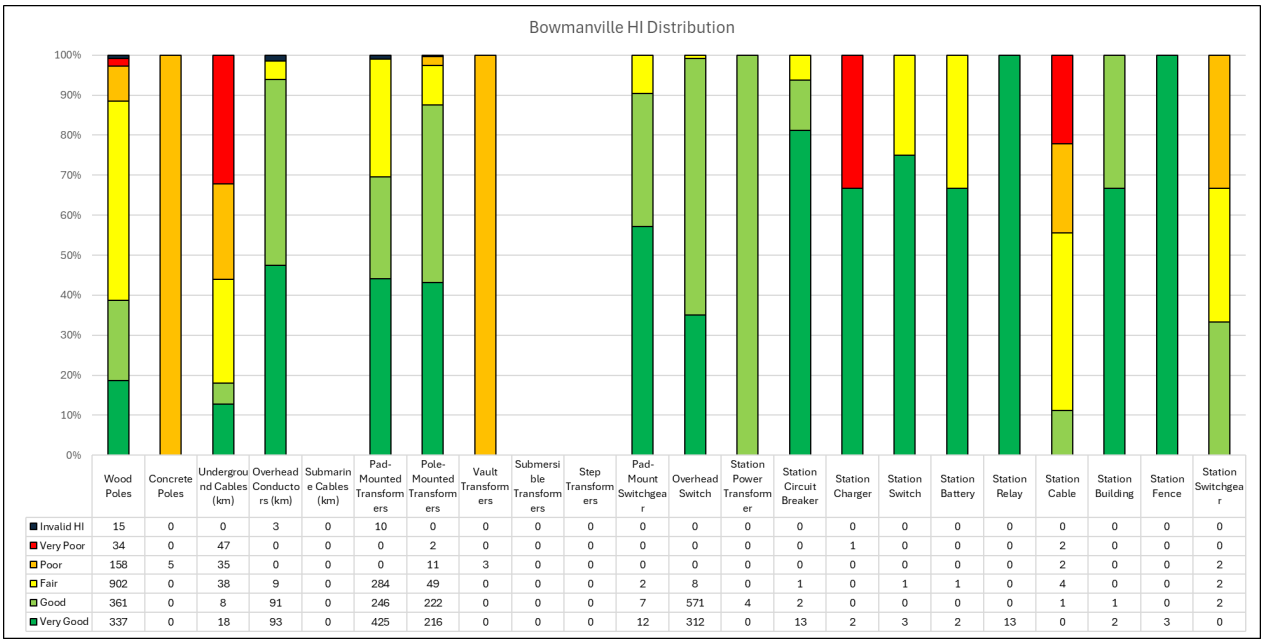


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	14	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	0	0
Already exceeded TUL	1401	2	49	0	0	83	327	85	0	0	1	17	8	25	4	0	0	21	5	6	4
Will Exceed TUL in the Next 5 Years	64	14	25	0	0	69	173	21	1	0	7	3	2	0	0	0	0	0	1	0	0
Has not exceeded TUL	1678	957	53	471	0	440	770	56	23	0	26	2427	2	9	11	10	35	20	5	4	5

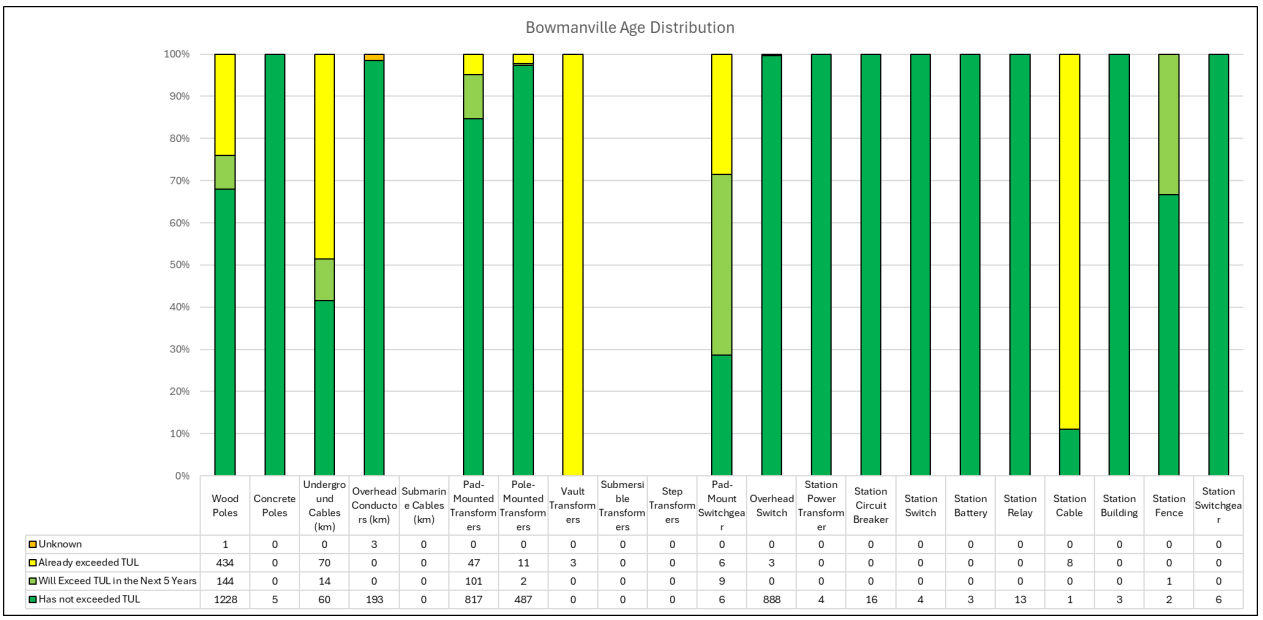
Figure 70: Belleville HI Results and Age Distribution

4.3.4. Bowmanville

The figures below present the HI results and age distribution in Bowmanville.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	15	0	0	3	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Very Poor	34	0	47	0	0	0	2	0	0	0	0	0	0	0	1	0	0	0	2	0	0	0
Poor	158	5	35	0	0	0	11	3	0	0	0	0	0	0	0	0	0	0	2	0	0	2
Fair	902	0	38	9	0	284	49	0	0	0	2	8	0	1	0	1	1	0	4	0	0	2
Good	361	0	8	91	0	246	222	0	0	0	7	571	4	2	0	0	0	0	1	1	0	2
Very Good	337	0	18	93	0	425	216	0	0	0	12	312	0	13	2	3	2	13	0	2	3	0

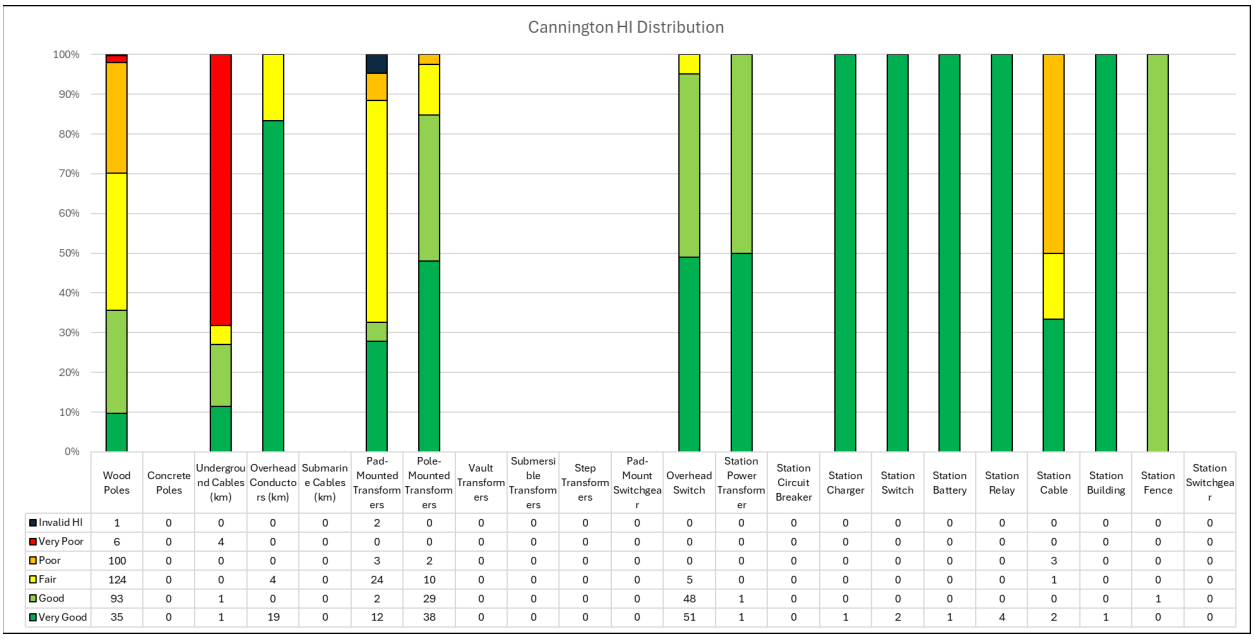


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	1	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	434	0	70	0	0	47	11	3	0	0	6	3	0	0	0	0	0	8	0	0	0
Will Exceed TUL in the Next 5 Years	144	0	14	0	0	101	2	0	0	0	9	0	0	0	0	0	0	0	0	1	0
Has not exceeded TUL	1228	5	60	193	0	817	487	0	0	0	6	888	4	16	4	3	13	1	3	2	6

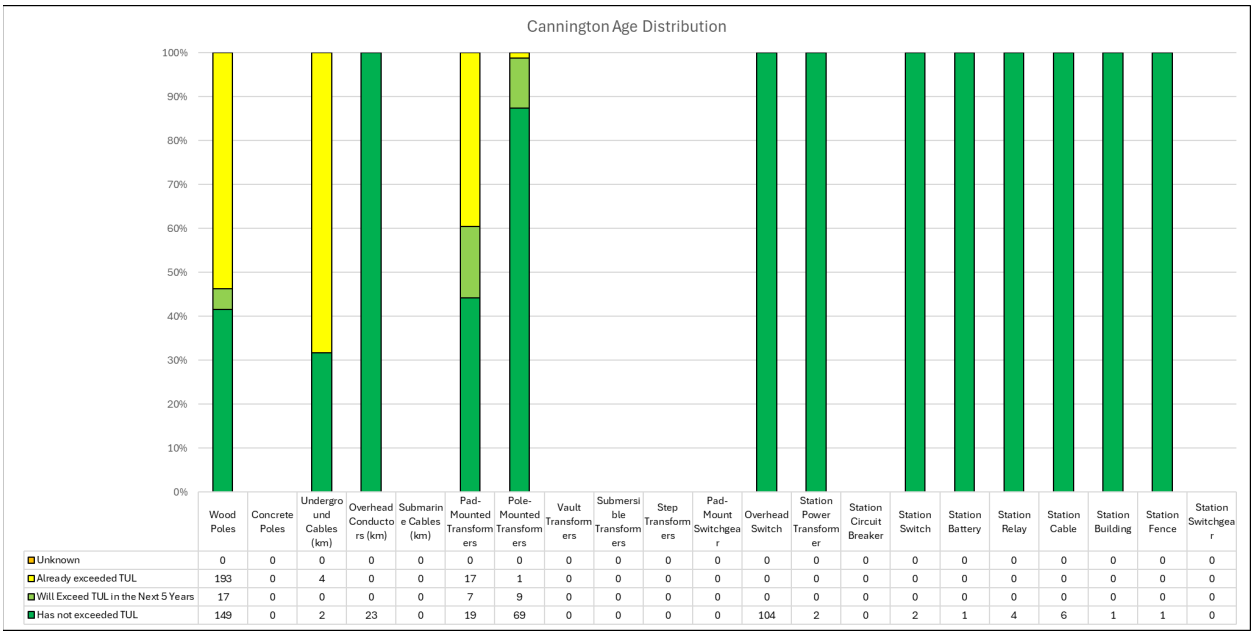
Figure 71: Bowmanville HI Results and Age Distribution

4.3.5. Cannington

The figures below present the HI results and age distribution in Cannington.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	1	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Very Poor	6	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poor	100	0	0	0	0	3	2	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0
Fair	124	0	0	4	0	24	10	0	0	0	0	5	0	0	0	0	0	0	1	0	0	0
Good	93	0	1	0	0	2	29	0	0	0	0	48	1	0	0	0	0	0	0	0	1	0
Very Good	35	0	1	19	0	12	38	0	0	0	0	51	1	0	1	2	1	4	2	1	0	0

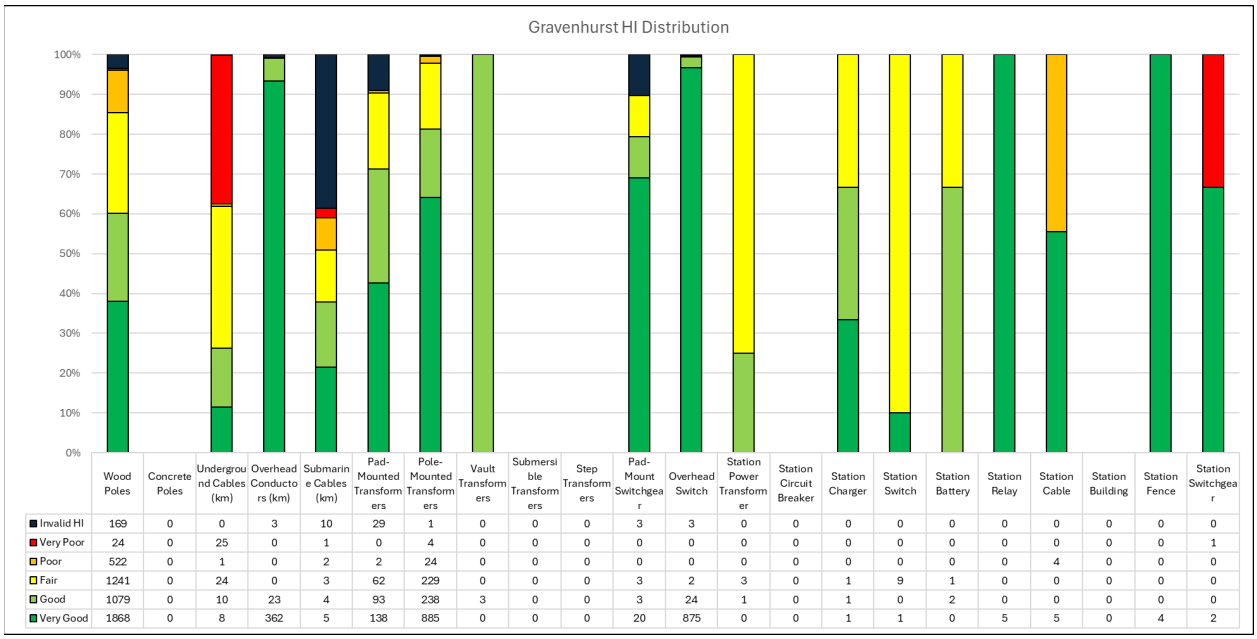


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	193	0	4	0	0	17	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Will Exceed TUL in the Next 5 Years	17	0	0	0	0	7	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Has not exceeded TUL	149	0	2	23	0	19	69	0	0	0	0	104	2	0	2	1	4	6	1	1	0

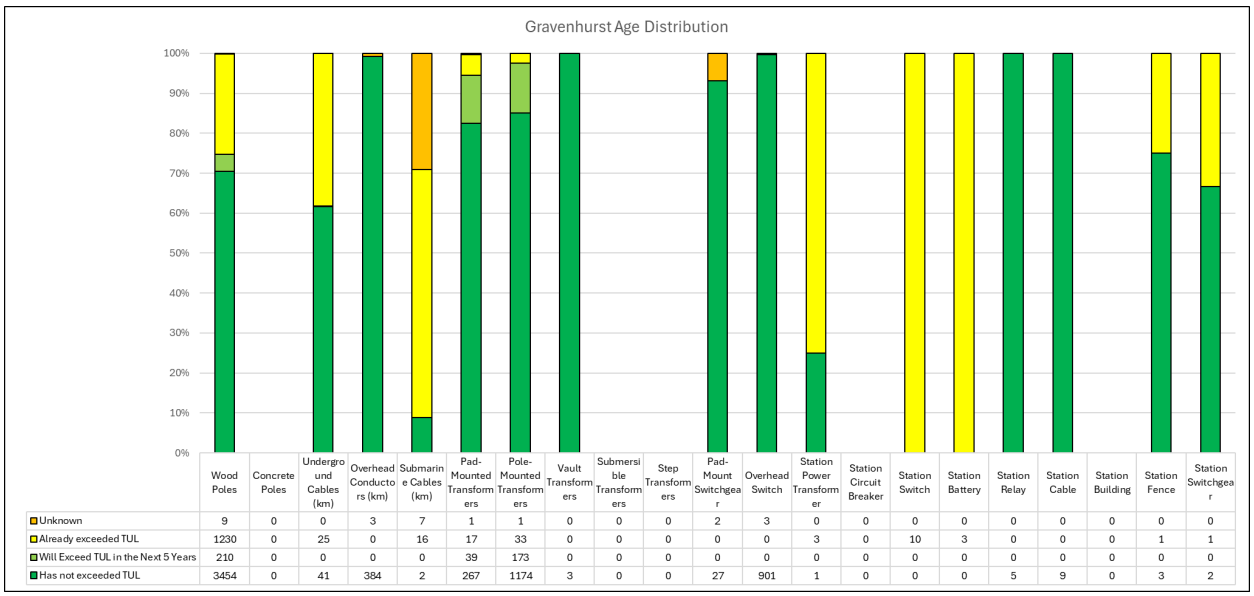
Figure 72: Cannington HI Results and Age Distribution

4.3.6. Gravenhurst

The figures below present the HI results and age distribution in Gravenhurst.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	169	0	0	3	10	29	1	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0
Very Poor	24	0	25	0	1	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Poor	522	0	1	0	2	2	24	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0
Fair	1241	0	24	0	3	62	229	0	0	0	3	2	3	0	1	9	1	0	0	0	0	0
Good	1079	0	10	23	4	93	238	3	0	0	3	24	1	0	1	0	2	0	0	0	0	0
Very Good	1868	0	8	362	5	138	885	0	0	0	20	875	0	0	1	1	0	5	5	0	4	2

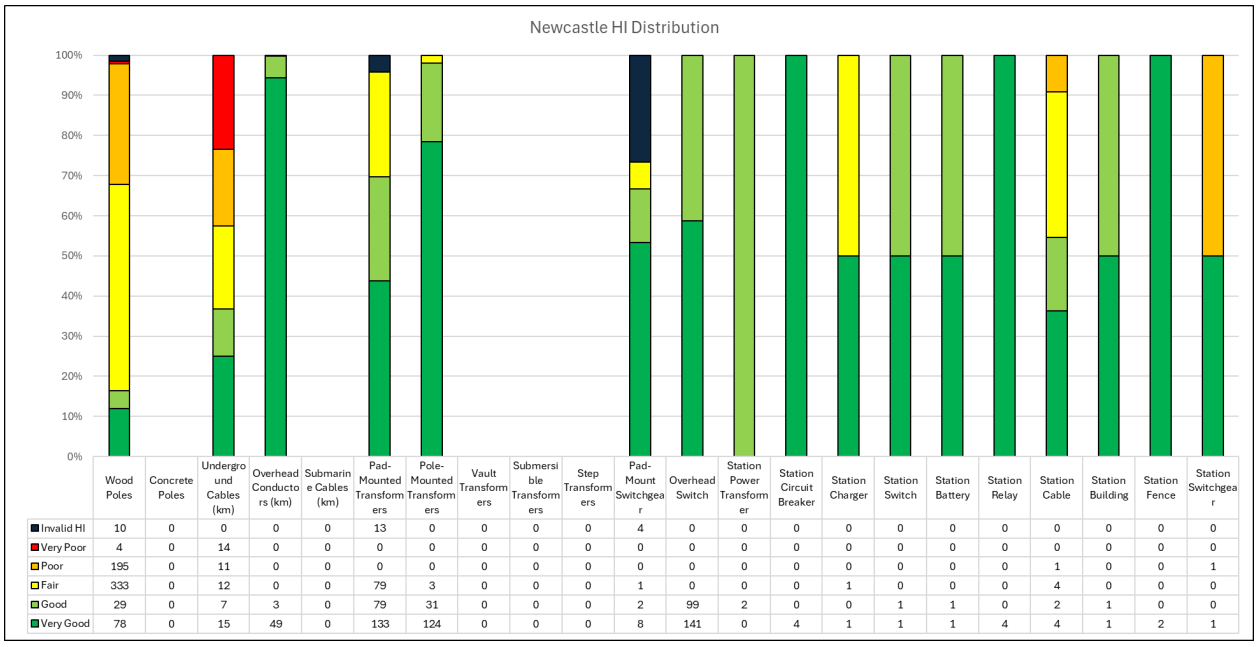


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	9	0	0	3	7	1	1	0	0	0	2	3	0	0	0	0	0	0	0	0	0
Already exceeded TUL	1230	0	25	0	16	17	33	0	0	0	0	0	3	0	10	3	0	0	0	1	1
Will Exceed TUL in the Next 5 Years	210	0	0	0	0	39	173	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Has not exceeded TUL	3454	0	41	384	2	267	1174	3	0	0	27	901	1	0	0	0	5	9	0	3	2

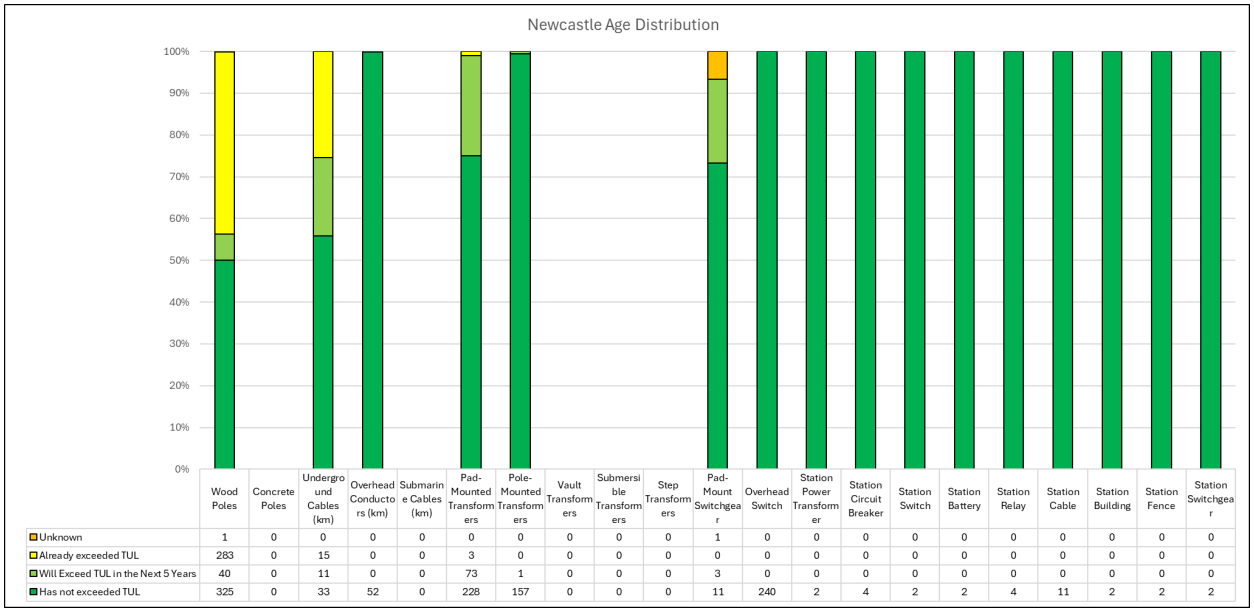
Figure 73: Gravenhurst HI Results and Age Distribution

4.3.7. Newcastle

The figures below present the HI results and age distribution in Newcastle.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	10	0	0	0	0	13	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0
Very Poor	4	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poor	195	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
Fair	333	0	12	0	0	79	3	0	0	0	1	0	0	0	1	0	0	0	4	0	0	0
Good	29	0	7	3	0	79	31	0	0	0	2	99	2	0	0	1	1	0	2	1	0	0
Very Good	78	0	15	49	0	133	124	0	0	0	8	141	0	4	1	1	1	4	4	1	2	1

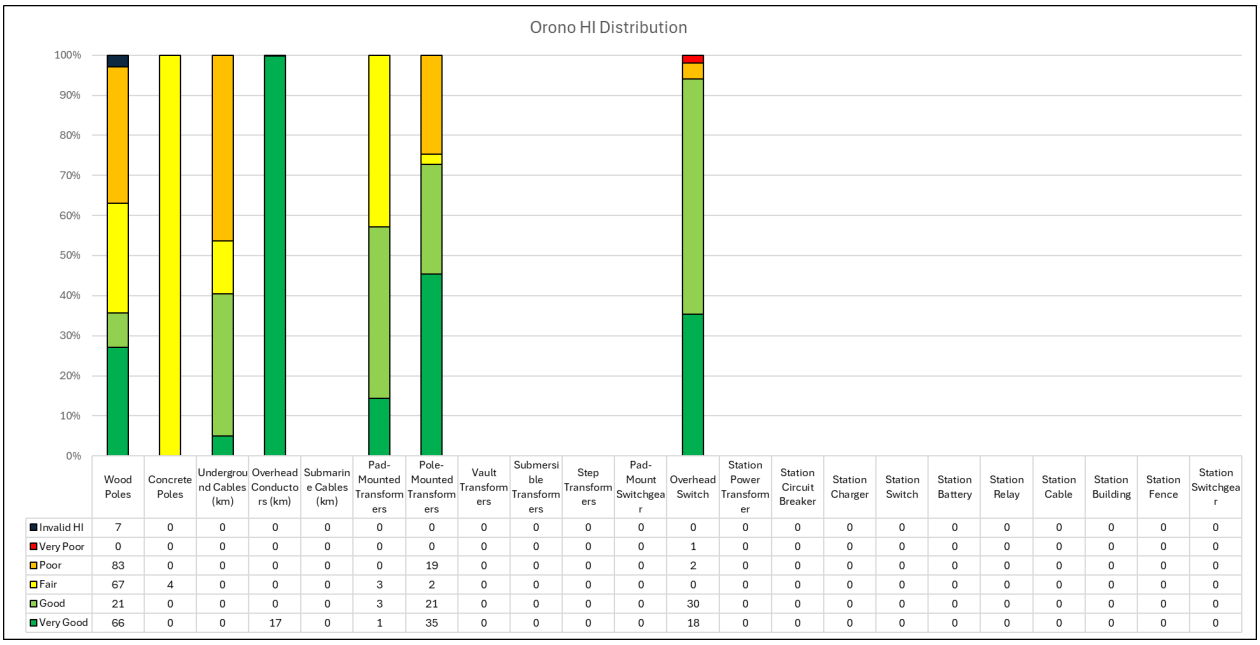


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	283	0	15	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Will Exceed TUL in the Next 5 Years	40	0	11	0	0	73	1	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Has not exceeded TUL	325	0	33	52	0	228	157	0	0	0	11	240	2	4	2	2	4	11	2	2	2

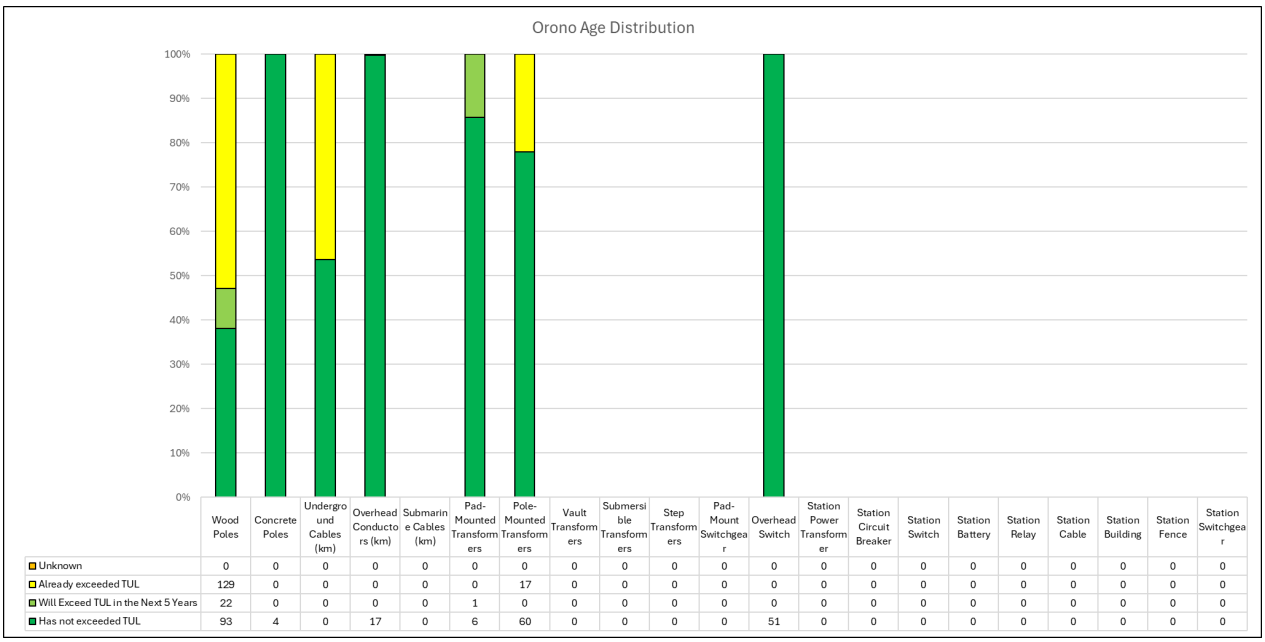
Figure 74: Newcastle HI Results and Age Distribution

4.3.8. Orono

The figures below present the HI results and age distribution in Orono.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Poor	83	0	0	0	0	0	19	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0
Fair	67	4	0	0	0	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Good	21	0	0	0	0	3	21	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0
Very Good	66	0	0	17	0	1	35	0	0	0	0	18	0	0	0	0	0	0	0	0	0	0

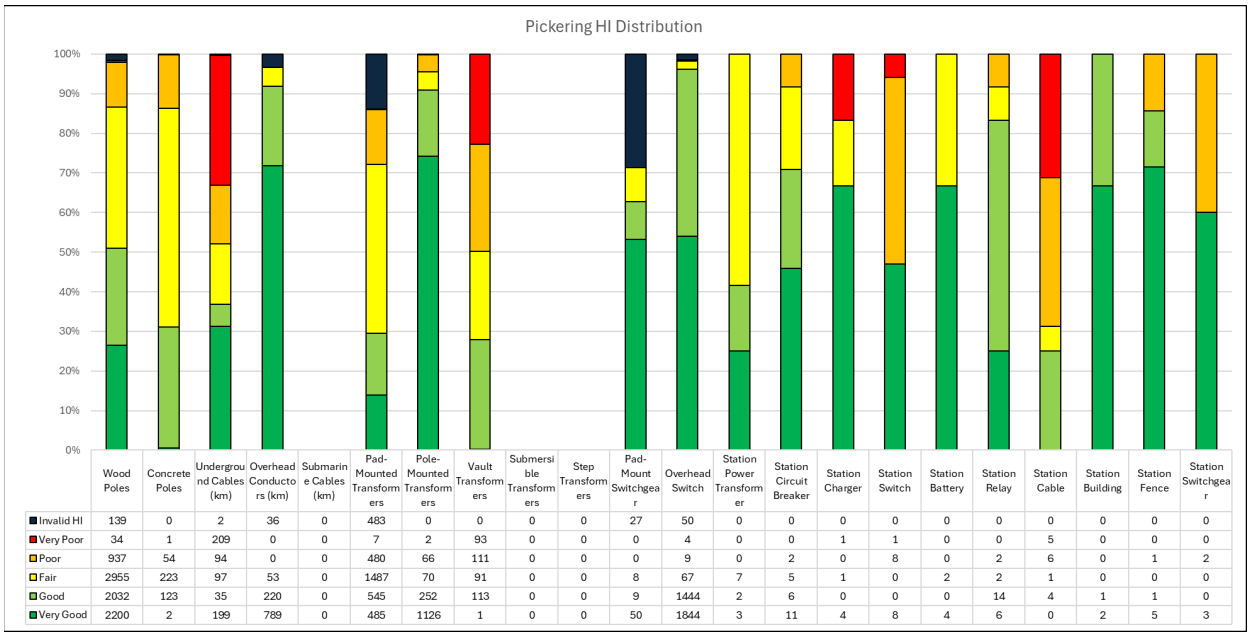


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	129	0	0	0	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Will Exceed TUL in the Next 5 Years	22	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Has not exceeded TUL	93	4	0	17	0	6	60	0	0	0	0	51	0	0	0	0	0	0	0	0	0

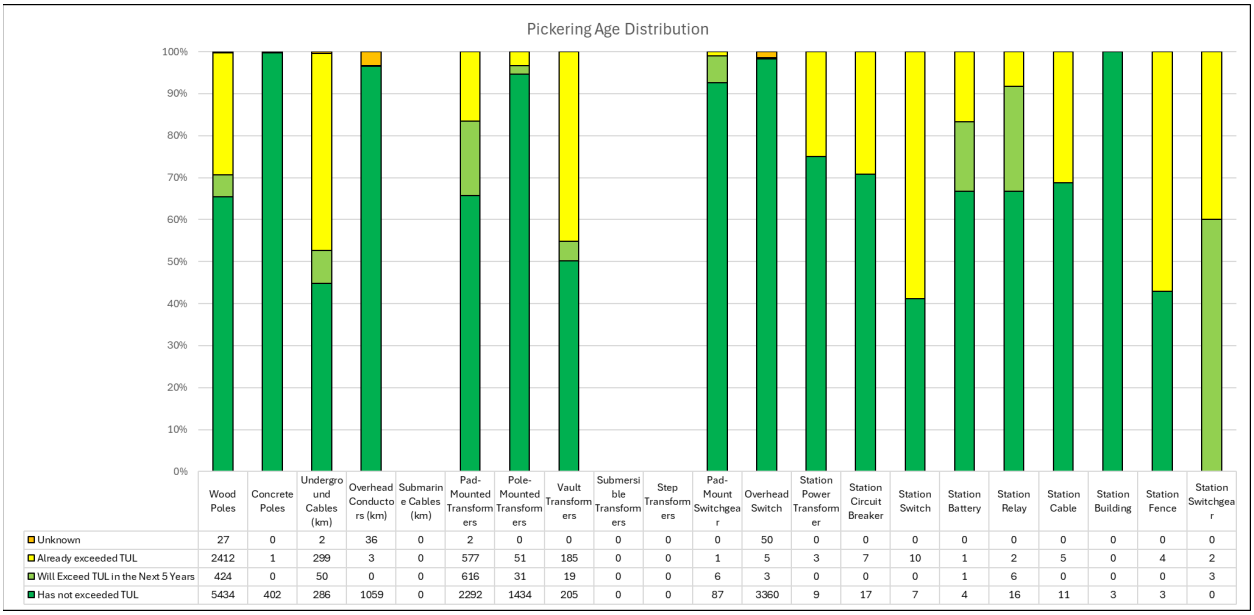
Figure 75: Orono HI Results and Age Distribution

4.3.9. Pickering

The figures below present the HI results and age distribution in Pickering.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	139	0	2	36	0	483	0	0	0	0	27	50	0	0	0	0	0	0	0	0	0	0
Very Poor	34	1	209	0	0	7	2	93	0	0	0	4	0	0	1	1	0	0	5	0	0	0
Poor	937	54	94	0	0	480	66	111	0	0	0	9	0	2	0	8	0	2	6	0	1	2
Fair	2955	223	97	53	0	1487	70	91	0	0	8	67	7	5	1	0	2	2	1	0	0	0
Good	2032	123	35	220	0	545	252	113	0	0	9	1444	2	6	0	0	0	14	4	1	1	0
Very Good	2200	2	199	789	0	485	1126	1	0	0	50	1844	3	11	4	8	4	6	0	2	5	3

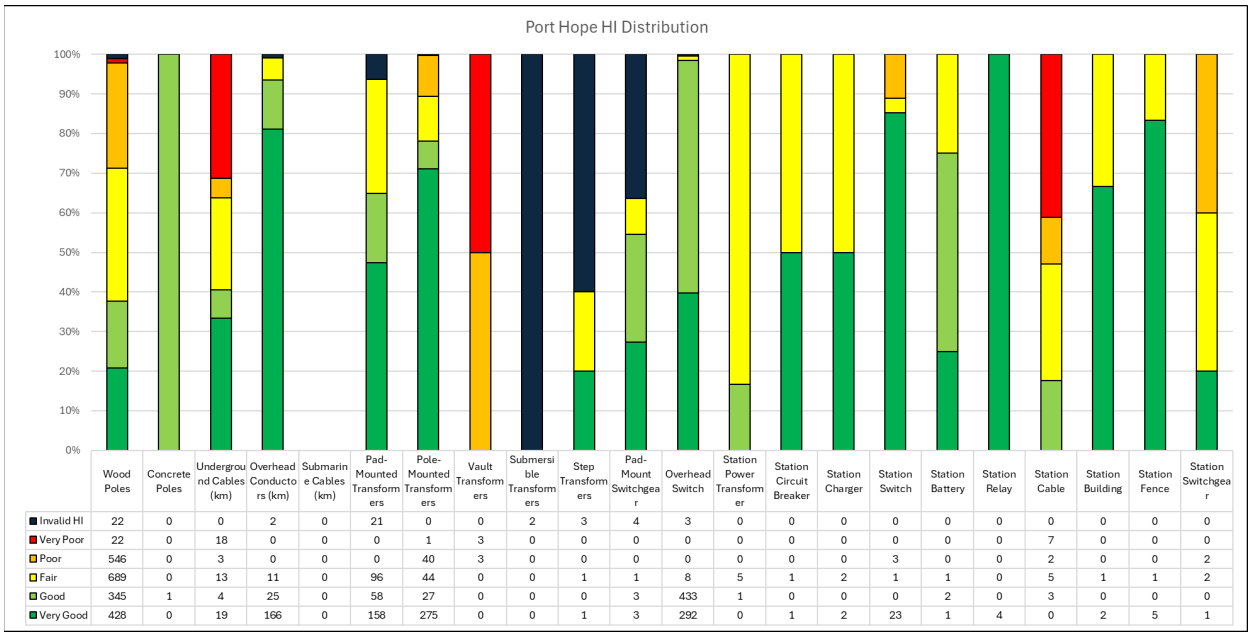


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	27	0	2	36	0	2	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0
Already exceeded TUL	2412	1	299	3	0	577	51	185	0	0	1	5	3	7	10	1	2	5	0	4	2
Will Exceed TUL in the Next 5 Years	424	0	50	0	0	616	31	19	0	0	6	3	0	0	0	1	6	0	0	0	3
Has not exceeded TUL	5434	402	286	1059	0	2292	1434	205	0	0	87	3360	9	17	7	4	16	11	3	3	0

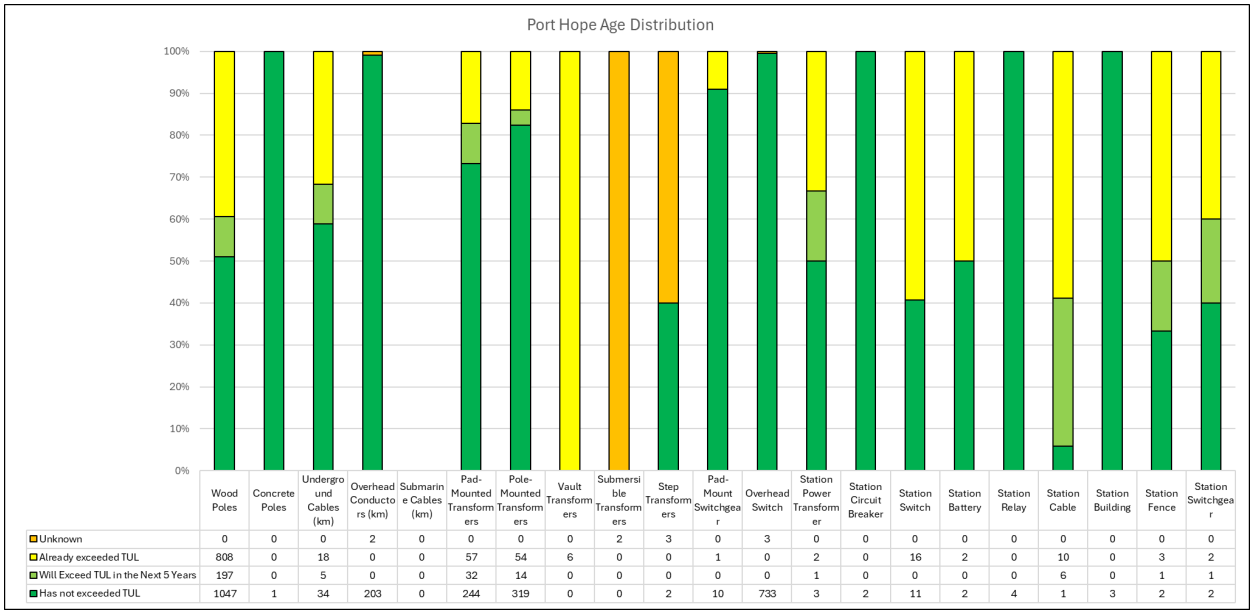
Figure 76: Pickering HI Results and Age Distribution

4.3.10. Port Hope

The figures below present the HI results and age distribution in Port Hope.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	22	0	0	2	0	21	0	0	2	3	4	3	0	0	0	0	0	0	0	0	0	0
Very Poor	22	0	18	0	0	0	1	3	0	0	0	0	0	0	0	0	0	0	7	0	0	0
Poor	546	0	3	0	0	0	40	3	0	0	0	0	0	0	0	3	0	0	2	0	0	2
Fair	689	0	13	11	0	96	44	0	0	1	1	8	5	1	2	1	1	0	5	1	1	2
Good	345	1	4	25	0	58	27	0	0	0	3	433	1	0	0	0	2	0	3	0	0	0
Very Good	428	0	19	166	0	158	275	0	0	1	3	292	0	1	2	23	1	4	0	2	5	1

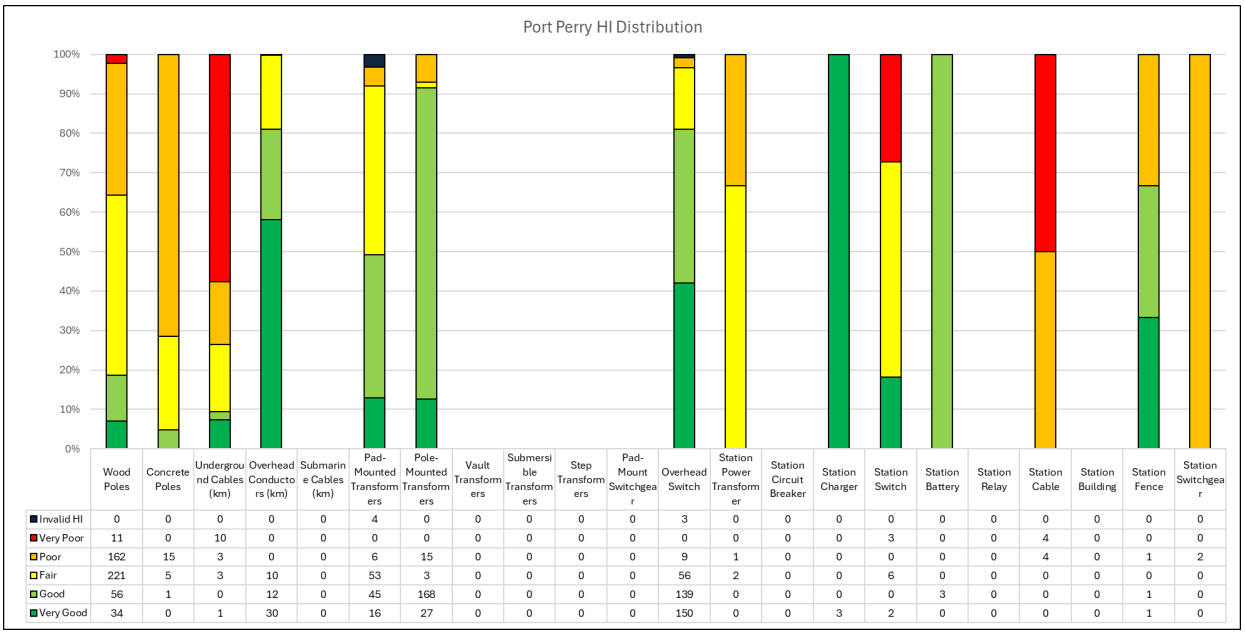


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	2	0	0	0	0	2	3	0	3	0	0	0	0	0	0	0	0	0
Already exceeded TUL	808	0	18	0	0	57	54	6	0	0	1	0	2	0	16	2	0	10	0	3	2
Will Exceed TUL in the Next 5 Years	197	0	5	0	0	32	14	0	0	0	0	0	1	0	0	0	0	6	0	1	1
Has not exceeded TUL	1047	1	34	203	0	244	319	0	0	2	10	733	3	2	11	2	4	1	3	2	2

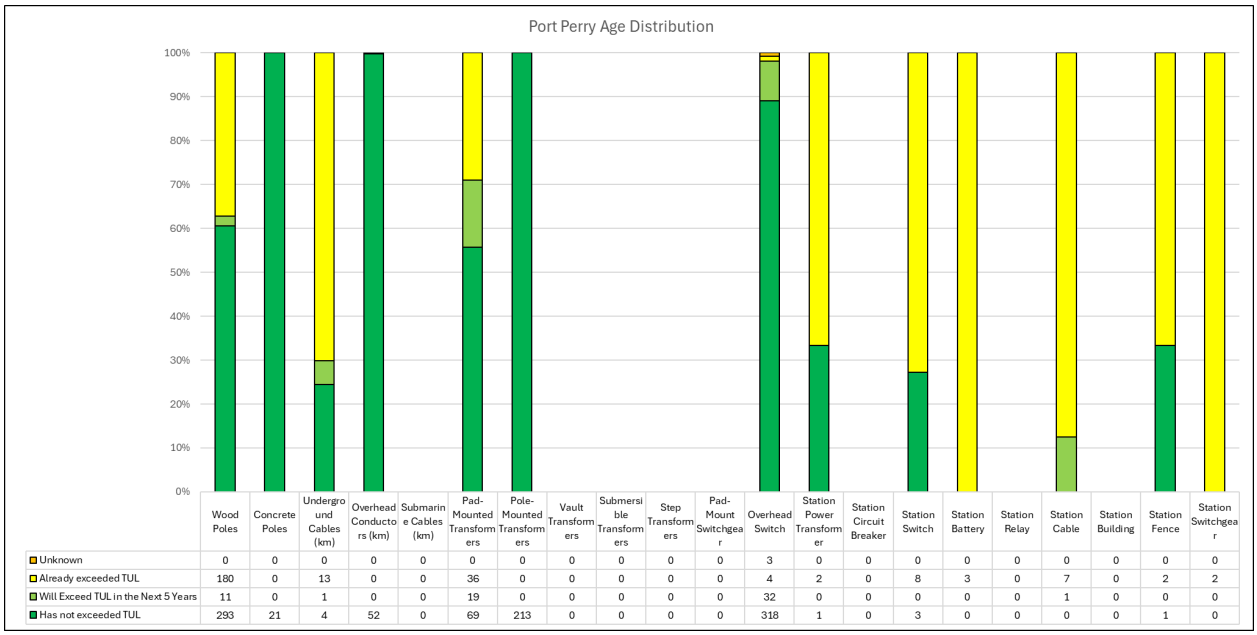
Figure 77: Port Hope HI Results and Age Distribution

4.3.11. Port Perry

The figures below present the HI results and age distribution in Port Perry.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	0	0	0	0	0	4	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Very Poor	11	0	10	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	4	0	0	0
Poor	162	15	3	0	0	6	15	0	0	0	0	9	1	0	0	0	0	0	4	0	1	2
Fair	221	5	3	10	0	53	3	0	0	0	0	56	2	0	0	6	0	0	0	0	0	0
Good	56	1	0	12	0	45	168	0	0	0	0	139	0	0	0	0	3	0	0	0	1	0
Very Good	34	0	1	30	0	16	27	0	0	0	0	150	0	0	3	2	0	0	0	0	1	0

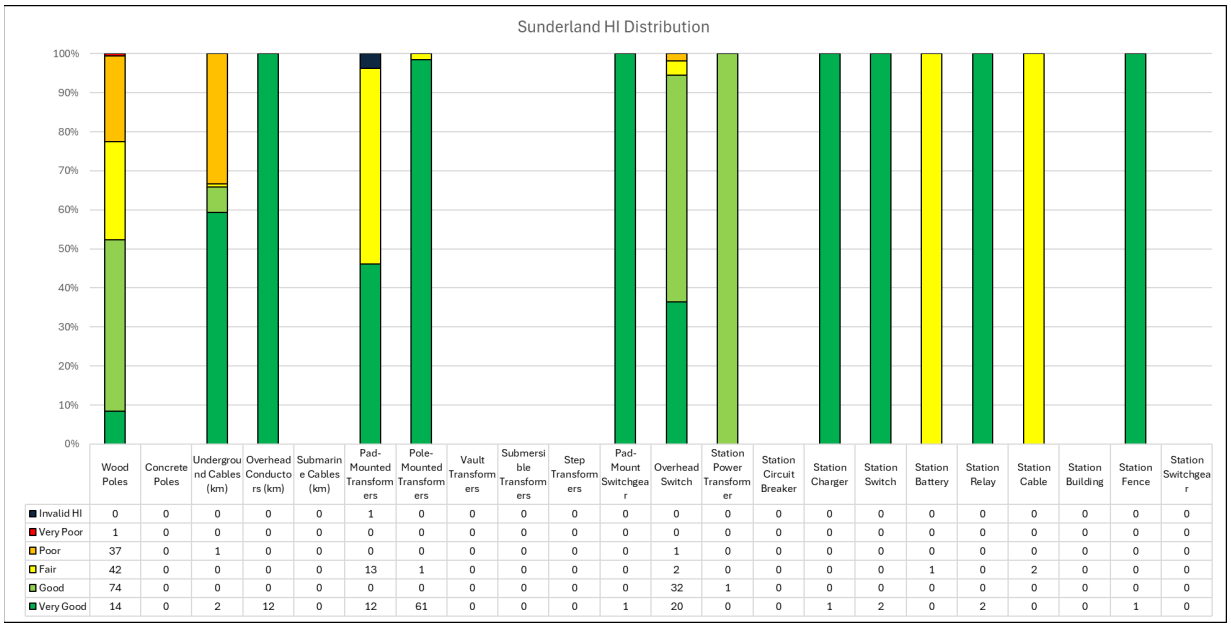


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0
Already exceeded TUL	180	0	13	0	0	36	0	0	0	0	0	4	2	0	8	3	0	7	0	2	2
Will Exceed TUL in the Next 5 Years	11	0	1	0	0	19	0	0	0	0	0	32	0	0	0	0	0	1	0	0	0
Has not exceeded TUL	293	21	4	52	0	69	213	0	0	0	0	318	1	0	3	0	0	0	0	1	0

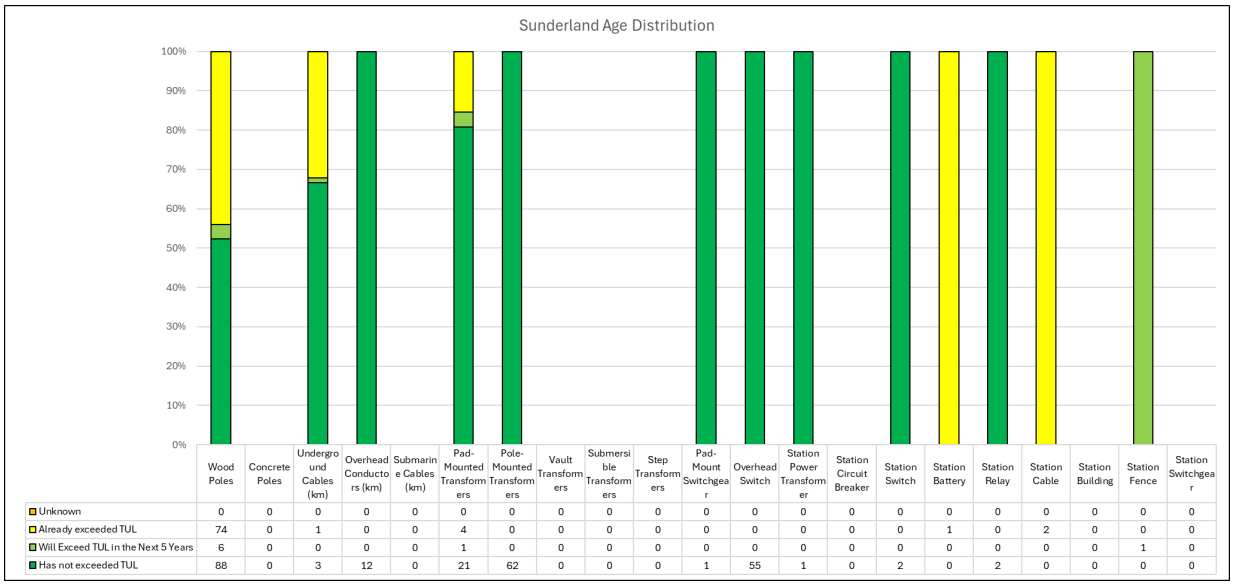
Figure 78: Port Perry HI Results and Age Distribution

4.3.12. Sunderland

The figures below present the HI results and age distribution in Sunderland.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Very Poor	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poor	37	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Fair	42	0	0	0	0	13	1	0	0	0	0	2	0	0	0	0	1	0	2	0	0	0
Good	74	0	0	0	0	0	0	0	0	0	0	32	1	0	0	0	0	0	0	0	0	0
Very Good	14	0	2	12	0	12	61	0	0	0	1	20	0	0	1	2	0	2	0	0	1	0

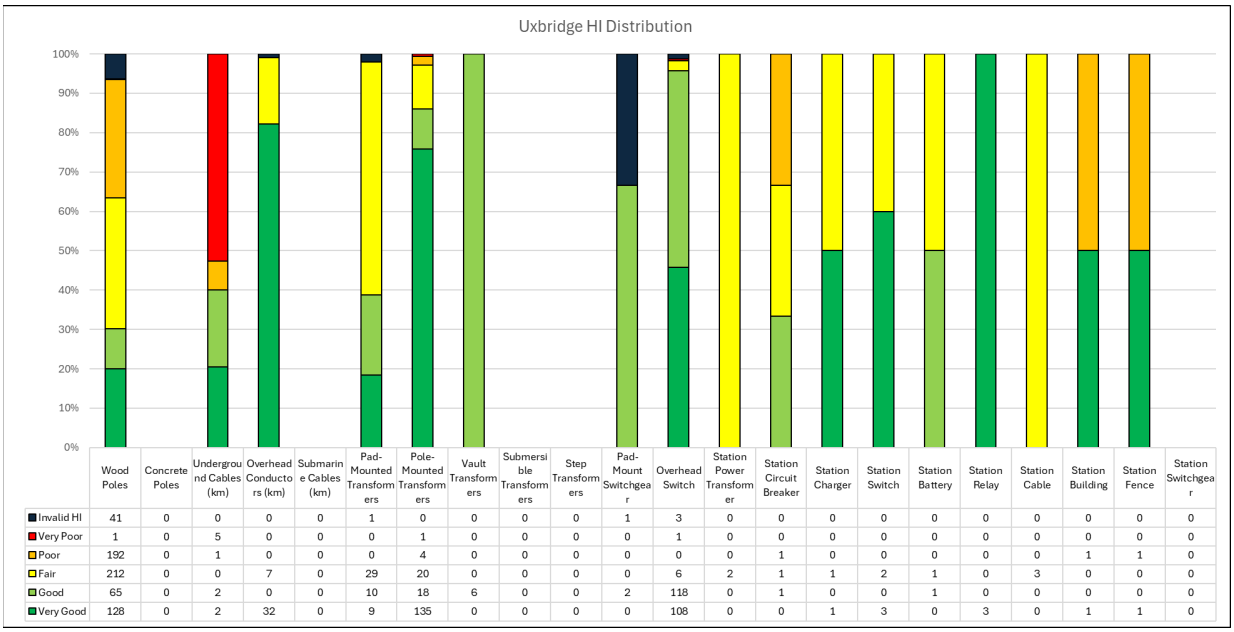


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Already exceeded TUL	74	0	1	0	0	4	0	0	0	0	0	0	0	0	0	1	0	2	0	0	0
Will Exceed TUL in the Next 5 Years	6	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Has not exceeded TUL	88	0	3	12	0	21	62	0	0	0	1	55	1	0	2	0	2	0	0	0	0

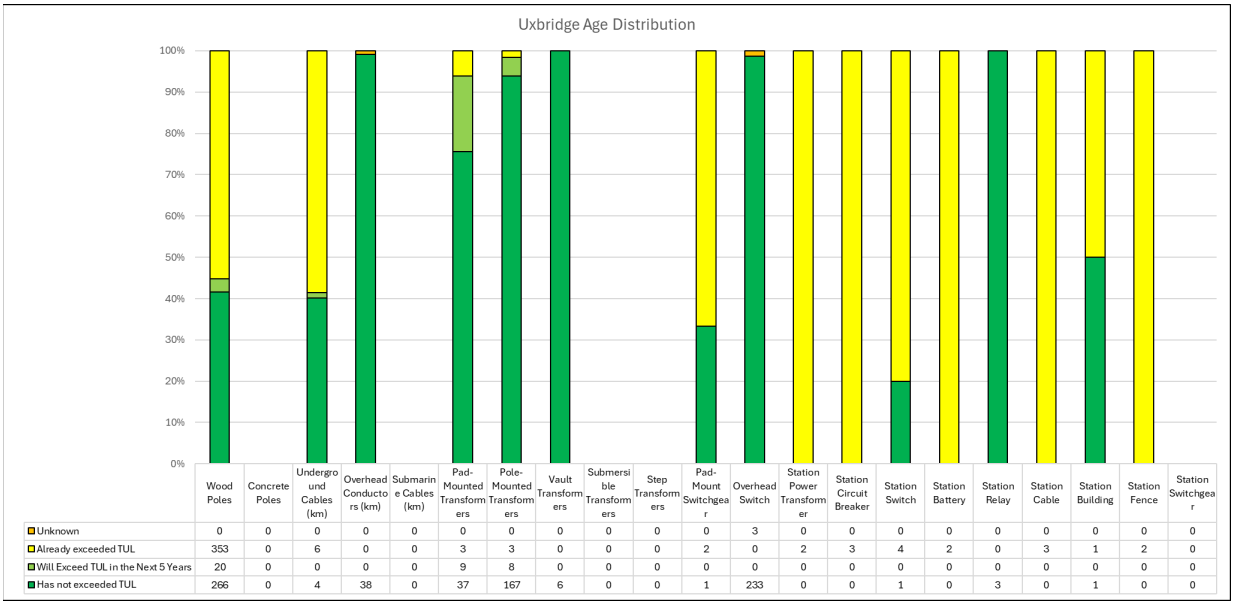
Figure 79: Sunderland HI Results and Age Distribution

4.3.13. Uxbridge

The figures below present the HI results and age distribution in Uxbridge.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	41	0	0	0	0	1	0	0	0	0	1	3	0	0	0	0	0	0	0	0	0	0
Very Poor	1	0	5	0	0	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Poor	192	0	1	0	0	0	4	0	0	0	0	0	0	1	0	0	0	0	0	1	1	0
Fair	212	0	0	7	0	29	20	0	0	0	0	6	2	1	1	2	1	0	3	0	0	0
Good	65	0	2	0	0	10	18	6	0	0	2	118	0	1	0	0	1	0	0	0	0	0
Very Good	128	0	2	32	0	9	135	0	0	0	0	108	0	0	1	3	0	3	0	1	1	0

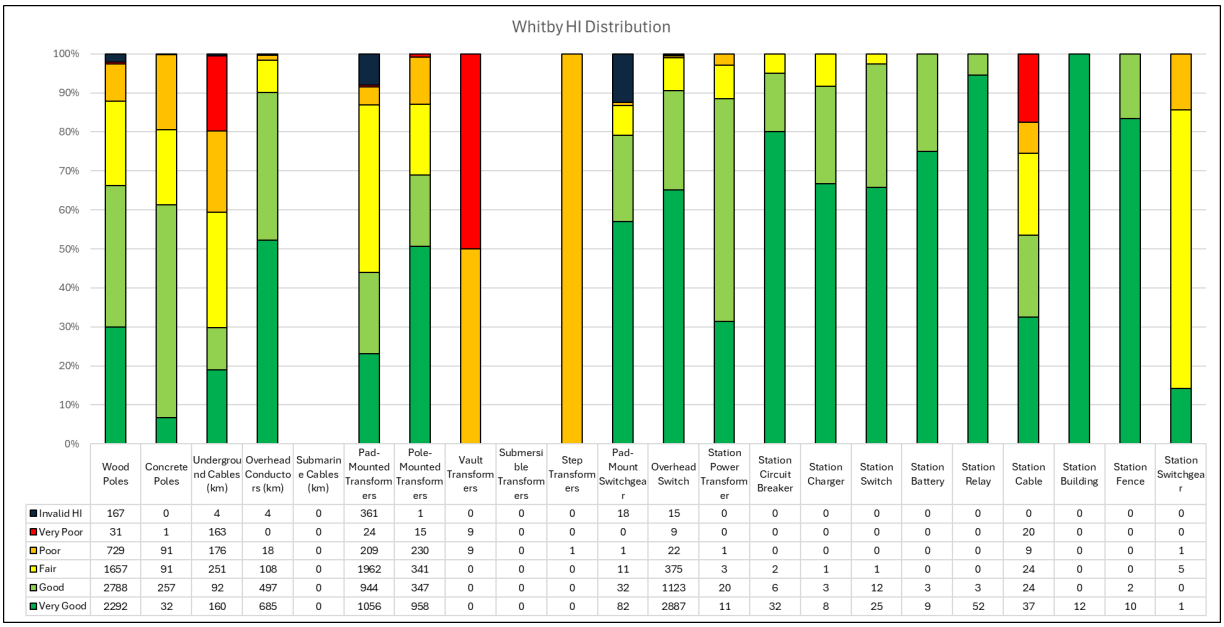


	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0
Already exceeded TUL	353	0	6	0	0	3	3	0	0	0	2	0	2	3	4	2	0	3	1	2	0
Will Exceed TUL in the Next 5 Years	20	0	0	0	0	9	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Has not exceeded TUL	266	0	4	38	0	37	167	6	0	0	1	233	0	0	1	0	3	0	1	0	0

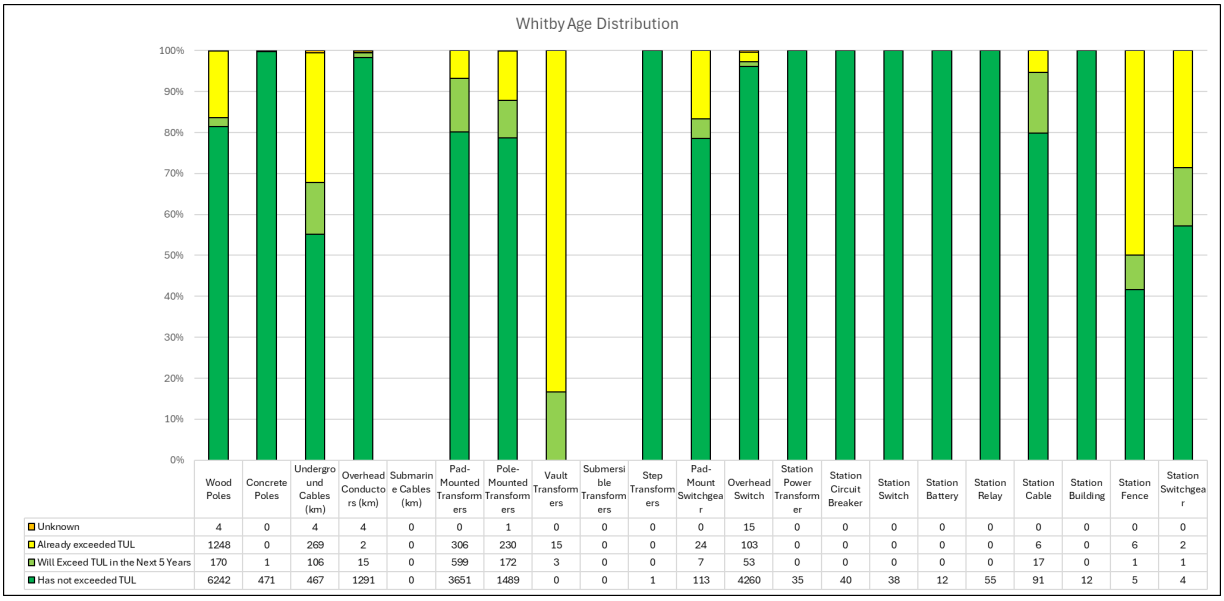
Figure 80: Uxbridge HI Results and Age Distribution

4.3.14. Whitby

The figures below present the HI results and age distribution in Whitby.



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Charger	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Invalid HI	167	0	4	4	0	361	1	0	0	0	18	15	0	0	0	0	0	0	0	0	0	0
Very Poor	31	1	163	0	0	24	15	9	0	0	0	9	0	0	0	0	0	0	20	0	0	0
Poor	729	91	176	18	0	209	230	9	0	1	1	22	1	0	0	0	0	0	9	0	0	1
Fair	1657	91	251	108	0	1962	341	0	0	0	11	375	3	2	1	1	0	0	24	0	0	5
Good	2788	257	92	497	0	944	347	0	0	0	32	1123	20	6	3	12	3	3	24	0	2	0
Very Good	2292	32	160	685	0	1056	958	0	0	0	82	2887	11	32	8	25	9	52	37	12	10	1



	Wood Poles	Concrete Poles	Underground Cables (km)	Overhead Conductors (km)	Submarine Cables (km)	Pad-Mounted Transformers	Pole-Mounted Transformers	Vault Transformers	Submersible Transformers	Step Transformers	Pad-Mount Switchgear	Overhead Switch	Station Power Transformer	Station Circuit Breaker	Station Switch	Station Battery	Station Relay	Station Cable	Station Building	Station Fence	Station Switchgear
Unknown	4	0	4	4	0	0	1	0	0	0	0	15	0	0	0	0	0	0	0	0	0
Already exceeded TUL	1248	0	269	2	0	306	230	15	0	0	24	103	0	0	0	0	0	6	0	6	2
Will Exceed TUL in the Next 5 Years	170	1	106	15	0	599	172	3	0	0	7	53	0	0	0	0	0	17	0	1	1
Has not exceeded TUL	6242	471	467	1291	0	3651	1489	0	0	1	113	4260	35	40	38	12	55	91	12	5	4

Figure 81: Whitby HI Results and Age Distribution

5. Recommendations

Advanced Asset Condition Parameters

BBA recommends that Elexicon should focus their efforts on collecting data for new condition parameters to improve the accuracy and add incremental value from a more granular approach. The advanced parameters typically represent the measurements associated with equipment degradation processes known to be most detrimental to the normal operation of electrical assets over time.

Recommendations target additional condition parameters or the means of collecting and storing the data already being utilized. Recommendations are based on the advanced ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted.

5.1.1. Wood Poles

Visual inspection processes should be modified to ensure that key data – particularly defects, wood rot, and vertical alignment – are collected as condition codes (A,B,C,D,E). Inspection services should be advised to give consistent reporting of remaining strength, preferably as a percentage of remaining life. Pole testing should be completed for all wood poles over ten years of age to verify the condition.

We note that aside from the gaps in the data records, Elexicon collects a substantial number of data parameters that enable the production of a relatively advanced HIF. Should the utility consider expanding the scope of inspection data collection, additional condition parameters for this asset class may include:

- Woodpecker damage; and
- Shell condition.

5.1.2. Concrete Poles

It should also be noted that concrete poles comprise only 5% of the pole population and, therefore, have a minimal impact on renewal planning. We also understand that Elexicon does not plan to replace the existing concrete poles with new concrete poles unless there is a specific customer request (and a funding contribution) supporting this approach. In all other instances, Elexicon plans to replace the end-of-life concrete poles with wood poles.

Nevertheless, the utility will continue operating a system that features a number of concrete poles for the foreseeable future. As such, near-term enhancements to the current data collection and tracking practices are in order. The collection of missing age data should be prioritized and a full visual inspection for each pole should take place.

Recognized HI guides recommend more than a two-parameter formulation to develop a robust index. A best-practice formulation would consider condition parameters such as:

- Evidence of rust/corrosion and spalling;
- Evidence of defects/overall condition; and
- Out of plumb.

Once more visual condition data is available, BBA recommends that Elexicon implement the following grading scheme:

Table 27: Criteria for Concrete Pole Defects

Condition Rating	Corresponding Condition
A	No signs of any defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
B	Signs of minor defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
C	Signs of significant defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
D	Signs of serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
E	Signs of very serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking

Table 28: Criteria for Concrete Pole Out of Plumb

Condition Rating	Corresponding Condition
A	There is no displacement of footings from the original installed condition, and there is no disorientation, the pole is perfectly straight

Condition Rating	Corresponding Condition
B	There is minor pole disorientation, but is acceptable and does not require corrective action
C	There is significant displacement of footings and/or there is significant disorientation, requiring planned corrective action
D	Major displacement of footings and/or major disorientation of the pole in present requiring immediate emergency repairs
E	Serious displacement of footings and disorientation of the pole in present requiring immediate emergency repairs

5.1.3. Underground Cables

We recommend that Elexicon should develop a complete AM Plan for underground cables. Decisions such as when to test and whether to inject cables or replace them should be rationalized. In addition, cable testing data should be tracked against cable demographics to correlate age and type with life expectancy.

Cable testing should also consider the condition of concentric neutral as it can pose safety risks when degraded. It is also recommended to inspect the condition of splices during cable testing.

The following types of condition information may assist Elexicon in its efforts to plan its replacement needs with additional confidence:

- Field testing results;
- Fault history;
- Load history;
- Condition of concentric neutral; and
- Visual inspection of terminations and splices.

Once there is more data regarding insulation condition, BBA recommends Elexicon use the following grading scheme:

Table 29: Criteria for Insulation Condition

Condition Rating	Corresponding Condition
A	Cable insulation is in good condition
C	Cable insulation is in fair condition
E	Cable insulation is in poor condition

5.1.4. Submarine Cables

BBA recommends that Elexicon develop a complete AM Plan for submarine cables. Decisions such as when to test or replace them should be rationalized. In addition, cable testing data should be tracked against cable demographics to correlate age and type with life expectancy.

The following types of condition information may assist Elexicon in its efforts to plan its replacement needs with additional confidence:

- Field testing results;
- Fault history; and
- Load history.

5.1.5. Overhead Conductors

Conductor age should be populated with the best available information. Typically, a conductor can be assumed to have been installed at the time the original pole lines were built, and there the typical pole age for the neighborhood or feeder can provide a useful estimate. OH conductor condition rarely drives reinvestment, and therefore, a common-sense approach to data collection is warranted including estimates and broad assumptions.

Best-practice formulations do not generally recognize the need for additional data collection on distribution overhead conductors. Accordingly, BBA does not suggest that Elexicon consider the collection of any additional condition parameters for this asset class.

5.1.6. Pole-Mounted Transformers

Age information should be collected for assets missing age data. It is recommended that Elexicon establish purchase dates, (or installed dates as a proxy) and transformer demographics for all pole-mounted transformers as part of a regular inspection. As data availability improves overall

condition should be added as an additional condition parameter. The same grading scheme used for pad-mounted transformers can be applied to this asset class.

Peak loading history should be considered as an additional condition parameter that may provide useful insight subject to the economics of assessing the remaining lives of Elexicon's pole-mounted transformer population for longer-term planning.

5.1.7. Pad-Mounted Transformers

At a minimum, age and condition data should be made available for all units because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number.

As part of the Asset Management Plan, an enhanced formulation based on criteria similar to pad-mounted switchgears would give a better indication of asset health. Suggested additional parameters include peak loading history, condition of structures/pads and IR scan results.

5.1.8. Vault Transformers

At a minimum, age and condition data should be made available for all installations because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number.

As part of the Asset Management Plan, an enhanced formulation based on criteria similar to pad-mounted transformer assets would give a better indication of asset health. Suggested additional parameters include peak loading history, the condition of other equipment within the vault (i.e., switching provisions, terminations) and IR scan. In some cases, the condition of the vault itself might be useful if the vault is not customer owned.

BBA recommends Elexicon use the following grading schemes:

Table 30: Criteria for Vault TX Condition of Civil Structure

Condition Rating	Corresponding Condition
A	Good Condition as new
C	Poor Condition; remedial action required
E	Civil structure degraded beyond repairs; Immediate replacement required

Table 31: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad-mounted transformers
B	Only one of the following defects: Minor rust, minor cracks in bushings, or minor oil leak
C	Two or more of the above-indicated defects present but do not impact the safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above-indicated defects

5.1.9. Submersible Transformers

At a minimum, age and condition data should be made available for all installations. As part of the Asset Management Plan, an enhanced formulation based on criteria similar to vault transformer assets would give a better indication of asset health. Suggested additional parameters include peak loading history, the condition of other equipment within the vault (i.e., switching provisions, terminations) and IR scan. In some cases, the condition of the vault itself might be useful if the vault is not customer owned.

5.1.10. Step Transformers

At a minimum, age and condition data should be made available for all installations. As part of the Asset Management Plan, an enhanced formulation based on criteria similar to vault transformer assets would give a better indication of asset health. Suggested additional parameters include peak loading history and IR scan.

5.1.11. Pad-Mounted Distribution Switchgear

As a minimum, age and condition data should be made available for all installations. Pad-mounted switchgear is often tracked by serial number because of the potential for switchgear to be removed from one location, rehabilitated, and then installed elsewhere. IR scans should be

completed for all pad-mounted switchgear to identify hotspots and collected as condition codes (A,B,C,D,E).

5.1.12. Overhead Switch

Condition data from visual inspection should be collected and translated into condition scores (A,B,C,D,E) and consolidated in the asset registry. Electronic field data collection methods are preferred.

In addition to the data currently being collected, a best-practice formulation may consider some additional condition parameters such as:

- Condition of operating mechanism; and
- Condition of terminations.

Considering the value of the three-phase OH switch asset to the operation of the utility, the collection of missing data should be prioritized for three-phase OH switches. Considering the relatively low value of the single-phase switch assets to the operation of the utility, missing data should be collected where economical. This will include updating inspection records and collecting missing age data. Moreover, as OH switches are replaced with newer technology, a series of other data points should be considered. A vacuum interrupting, three-phase device controlled by SCADA or automation is sufficiently different from a three-phase traditional switch to justify its own asset class. In addition, the device could be oil or gas-filled and have an operations limit. Some of the additional condition parameters that may warrant collecting for such a device include:

- Counter readings/operations;
- Condition of tank/enclosure;
- Condition of the control box;
- Condition of battery/charger system;
- Condition/operability of the communications system;
- Oil condition or leaks;
- Vacuum bottle integrity;
- SF6; and
- Technical obsolescence.

5.1.13. Power Transformers

The condition data Elexicon collects results for power transformers results in a comprehensive and detailed HIF. Additional condition parameters to be included in future iterations of the ACA include are:

- Load history;
- IR scan; and
- Insulation Moisture Content.

5.1.14. Circuit Breakers and Reclosers

As station breakers are renewed over time and new stations are built, new technology is likely to be introduced into the system, warranting the formulation of more comprehensive and/or sub-asset class-specific HIF. Additional condition parameters to be included in future iterations of the ACA include:

- Counter Readings;
- Condition of bushings and support insulators;
- IR Scan;
- Air Leaks (if applicable);
- Air Consumption Test (if applicable);
- Vacuum bottle integrity (if applicable);
- Vacuum interrupter condition (if applicable);
- Oil leaks (if applicable);
- Oil analysis (if applicable);
- SF6 leaks (if applicable); and
- SF6 Gas analysis (if applicable).

5.1.15. Station Switches

5.1.16. Station Batteries and Chargers

For future iterations of the ACA, a separate HIF can be developed for station chargers that incorporates both service age and visual condition. BBA recommends the following grading scheme for station chargers:

Table 32: Service Age for Station Chargers

Condition Rating	Service Age
A	0 to 6 years
B	7 to 13 years
C	14 to 20 years
D	21 to 26 years
E	Over 26 years

5.1.17. Station Relays

The mean time between failures (tracked for each given relay type) and discretionary or non-discretionary obsolescence should be considered for future iterations of the ACA. Additional condition parameters to be included in future iterations of the ACA include:

- Mean time between failures (per relay type); and
- Discretionary or non-discretionary obsolescence.

Discretionary obsolescence refers to a utility's own decision grounded in a policy or standard change to phase out a certain type of equipment. Non-discretionary obsolescence, on the other hand, is a function of certain relay units exceeding the term of their extended support/warranty by vendors, compatibility issues between a given relay type and the utility's evolving communications network, or the availability of replacement parts for a given relay type to enable the refurbishment of in-service units.

5.1.18. Station Cables

The condition parameters collected by Elexicon for station cables provides a comprehensive HIF. BBA recommends that Elexicon record station cables by length for future ACA studies to produce a more practical HI distribution inline with UG cables, submarine cables, and OH conductors.

5.1.19. Station Buildings

The visual inspection parameters collected by Elexicon for station buildings provides a comprehensive HIF. Although its impact would be relatively minor, service age can be integrated in the HIF in future iterations of the ACA.

BBA recommends the following grading scheme for station buildings:

Table 33: Service Age for Station Buildings

Condition Rating	Service Age
A	0 to 20 years
B	21 to 40 years
C	41 to 60 years
D	61 to 80 years
E	Over 80 years

5.1.20. Station Fences

The visual inspection parameters collected by Elexicon for station buildings provides a comprehensive HIF. Additional condition parameters to be included in future iterations of the ACA include:

- Signage; and
- Yard – Condition/Vegatation/Debris.

5.1.21. Station Switchgears

The testing and visual inspection parameters collected by Elexicon for station switchgears provides a comprehensive HIF. Additional condition parameters for Elexicon to consider in future iterations of the ACA include:

- Equipment Failure History; and
- IR Scan.

5.2. Additional Asset Class Considerations

In addition to including advanced condition parameters to already existing HIFs, BBA recommends the following station asset classes be considered for future iterations of the ACA study:

- Primary Bus Structures; and
- Station Grounding.

Currently, Elexicon does not use a specific inspection sheet to record condition data for Primary Bus Structures. Instead, the condition would have to be derived from the inspection of its comprised components.

As part of their regular planned maintenance, Elexicon performs resistance tests on their station ground grids. To properly score the ground grid resistance, BBA recommends recording the Single Line to Ground (SLG) fault current. The condition rating for the ground resistance test depends on whether the Ground Potential Rise (GPR) is within the specification as defined in the Ontario Electrical Safety Code (OESC); where GPR is the product of ground resistance and SLG fault level.

6. Conclusion

On top of a condition assessment of Elexicon's major asset classes, this report provided Elexicon with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance its asset management analytics.

As a general recommendation across all asset classes, Elexicon's visual inspection should follow be consolidated as condition codes (A,B,C,D,E). Furthermore, data each asset class was delivered to BBA over multiple files (GIS data, inspection records, maintenance files, IR scan reports, etc.). BBA recommends implementing a consolidated asset database for each asset class. As our final recommendation, we suggest that Elexicon invest some time and analytical resources into the development of a comprehensive Strategic Asset Management Plan ("SAMP") that would prescribe the utility's unified approach to the collection and management of asset data for each asset class.

The amount of asset condition information that Elexicon made available for BBA in the context of this study exceeded the sum of data that was included in earlier iterations of the ACA study. The amount of data provided and the additional insights derived from the data enchancments initative affirms Elexicon's commitment to the continuous improvement. BBA expects these efforts to continue over the forseable future as Elexicon refines its strategic priorities within the AM function and beyond. BBA commends Elexicon for their significant improvements in data collection and digitization of asset records.

This concludes BBA's Asset Condition Assessment report for Elexicon's assets. We thank Elexicon's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

Appendix A: Condition Parameter Grading Tables

A.1 Wood Poles

Table A-1: Criteria for Service Age (Wood Poles)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

Table A-2: Criteria for Remaining Strength of Wood Poles

Condition Rating	Corresponding Condition
A	91% to 100%
B	81% to 90%
C	71% to 80%
D	61% to 70%
E	Less than 60%

Table A-3: Criteria for Overall Condition (Wood Poles)

Condition Rating	Corresponding Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component requires immediate replacement

Table A-4: Criteria for Wood Rot

Condition Rating	Corresponding Condition
A	There is no wood rot
B	Slight wood rot in a few areas
C	Slight wood rot is present in many areas and/or moderate wood rot present
D	Moderate rot was present in a few locations or Extensive wood rot was noted in the inspection
E	Wood rot is extensive in many areas

Table A-5: Criteria for Out of Plumb (Wood Poles)

Condition Rating	Corresponding Condition
A	Pole is not leaning
E	Pole is leaning

A.2 Concrete Poles

Table A-6: Criteria for Service Age (Concrete Poles)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

A.3 Underground Cables

Table A-7: Criteria for Service Age (XPLE, Direct-buried)

Condition Rating	Corresponding Condition
A	0 to 8 years

Condition Rating	Corresponding Condition
B	9 to 16 years
C	17 to 25 years
D	26 to 33 years
E	34 years or older

Table A-8: Criteria for Service Age (TR-XPLE, Direct-buried)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-9: Criteria for Service Age (XPLE, In Duct)

Condition Rating	Corresponding Condition
A	0 to 8 years
B	9 to 16 years
C	17 to 25 years

Condition Rating	Corresponding Condition
D	26 to 33 years
E	34 years or older

Table A-10: Criteria for Service Age (TR-XPLE, In Duct)

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	54 years or older

Table A-11: Criteria for Number of Splices

Condition Rating	Corresponding Condition
A	Splice is not present on the cable segment
C	One splice is present on the cable segment
E	Two or more splices are present on the cable segment

A.4 Submarine Cables

Table A-12: Criteria for Service Age (Submarine Cables)

Condition Rating	Corresponding Condition
A	0 to 8 years
B	9 to 16 years
C	17 to 25 years
D	26 to 33 years
E	34 years or older

Table A-13: Criteria for Condition of Concentric Neutral

Condition Rating	Corresponding Condition
A	No abnormalities detected
B	Minor signs of abnormalities
C	Significant signs of abnormalities, Un-jacketed bare concentric neutral-sandy soil
D	Serious signs of abnormalities, Un-jacketed bare concentric neutral-sandy soil
E	Very serious signs of abnormalities, One half/one third neutral size underground distribution cable with known neutral corrosion; full neutral size underground distribution cable with known neutral corrosion

Table A-14: Criteria for Condition of Armor/Sheath/Jacket

Condition Rating	Corresponding Condition
A	No abnormalities or signs of water ingress into insulation, rusting/corrosion detected
B	Minor signs of abnormalities, water ingress into insulation or rusting/corrosion detected
C	Significant signs of abnormalities, water ingress into insulation or rusting/corrosion detected
D	Serious signs of abnormalities, water ingress into insulation or rusting/corrosion detected
E	Very serious signs of abnormalities, water ingress into insulation or rusting/corrosion detected

Table A-15: Criteria for Visual Inspection of Terminations

Condition Rating	Corresponding Condition
A	Pot head (for PILC cables) or stress cone terminations (for XLPE cables) appear to be in good condition, no indication of moisture ingress
B	Minor wear, no apparent damage, no evidence of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
D	Poor condition, potential moisture ingress or IR indicates hot spot

Condition Rating	Corresponding Condition
E	Very Poor condition, potential moisture ingress or IR indicates hot spot

A.5 Overhead Conductors

Table A-16: Criteria for Service Age (OH Conductors)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 60 years
E	81 years or older

Table A-17: Criteria for Small Conductor Risk

Condition Rating	Corresponding Condition
A	Absence of small-sized conductors
E	Presence of small-sized conductors (#2, #4, or #6 copper)

A.6 Pole-Mounted Transformers

Table A-18: Criteria for Service Age (Pole-Mounted Transformers)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-19: Criteria for IR Scan (Pole-Mounted Transformers)

Condition Rating	Corresponding Condition
A	No hot spots were detected; no deficiency identified for the transformer and no further action required
B	Minor temperature rises between 0 to 10°C; continue to monitor transformer for further degradation
C	Intermediate temperature rises between 10 to 20°C; maintenance required at next available outage
D	Serious temperature rises between 20 to 30°C; maintenance is required as soon as possible
E	Critical temperature rises larger than 30°C; immediate action is required to correct the issue

A.7 Pad-Mounted Transformer

Table A-20: Criteria for Service Age (Pad-Mounted TX)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-21: Criteria for Overall Condition (Pad-Mounted TX)

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad-mounted transformers
B	Only one of the following defects: Minor rust, minor cracks in bushings, or minor oil leak
C	Two or more of the above-indicated defects present but do not impact the safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above-indicated defects

A.8 Vault and Step Transformers

Table A-22: Criteria for Service Age (Vault & Step TX)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

A.9 Submersible Transformers

Table A-23: Criteria for Overall Condition (Submersible TX)

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on submersible transformers
B	Only one of the following defects: Minor rust, minor cracks in bushings, or minor oil leak
C	Two or more of the above-indicated defects present but do not impact the safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above-indicated defects

Table A-24 Criteria for Service Age (Submersible TX)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

A.10 Pad-Mounted Distribution Switchgears

Table A-25: Criteria for Enclosure Condition

Condition Rating	Corresponding Condition
A	No signs of rust on the tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
B	Minor signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
C	Significant signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
D	Major signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents
E	Serious signs of rust on tank/enclosure, or damage on the enclosure due to corrosion, dirt/contamination, or vehicle accidents

Table A-26: Criteria for Condition of Interphase Barriers

Condition Rating	Corresponding Condition
A	No signs of damage or cracks in the interphase barriers
B	Signs of minor damage or cracks in the interphase barriers
C	Signs of significant damage or cracks in the interphase barriers
D	Signs of serious damage or cracks in the interphase barriers
E	Signs of very serious damage or cracks in the interphase barriers

Table A-27: Criteria for Condition of Terminations

Condition Rating	Corresponding Condition
A	Terminations are tight, free from corrosion, and show no sign of overheating. Cables are adequately supported and impose no excessive loading on switchgear during normal or fault interrupting duty
B	Minor signs of wear with respect to the above characteristics
C	Significant signs of degradation with respect to the above characteristics, but they do not impact the safe operation of the switchgear
D	Serious deficiencies with respect to the above-listed characteristics requiring repairs during the next scheduled outage
E	Very serious deficiencies with respect to the above-listed characteristics requiring immediate repairs or replacement

Table A-28: Criteria for Condition of Operating Mechanism

Condition Rating	Corresponding Condition
A	Operating mechanism is in good condition. No sign of overheating or deterioration. No evidence of moisture or condensation or insect ingress into control cabinet
B	Normal signs of wear of control components based on the above listed characteristics
C	Significant wear of control components based on the above listed characteristics, but it does not affect safe operation of the switchgear
D	Unacceptable level of degradation of control components based on the above listed characteristics, requiring component replacement/repairs during the next scheduled outage
E	Switch operator controls defective, damaged, or degraded, requiring immediate replacement

Table A-29: Criteria for Condition of Pad- Mounted Switchgears

Condition Rating	**Corresponding Condition**
A	Good condition as new
B	Normal sign of wear
C	Significant sign of wear
D	Poor condition, remedial action required
E	Immediate replacement required

Table A-30: Criteria for Service Age (Pad-Mounted Switchgears)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-31: Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots detected; no deficiency identified for switchgear and no further action required
B	Minor temperature rises between 0 to 10°C; continue to monitor switchgear for further degradation
C	Intermediate temperature rises between 10 to 20°C; maintenance required at next available outage
D	Serious temperature rises between 20 to 30°C; maintenance is required as soon as possible
E	Critical temperature rises larger than 30°C; immediate action is required to correct the issue

A.11 Overhead Switches

Table A-32: Criteria for Service Age (OH Switches)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-33: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No damage to connections, insulators, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	One or two of the above indicated defects present but does not impact safe operation
D	More than two of the above indicated defects, but they can be repaired
E	More than two or more of the above indicated defects, but they cannot be repaired

Table A-34: Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots detected; no deficiency identified for switch and no further action required
B	Minor temperature rises between 0 to 10°C; continue to monitor switch for further degradation
C	Intermediate temperature rises between 10 to 20°C; maintenance required at next available outage
D	Serious temperature rises between 20 to 30°C; maintenance is required as soon as possible
E	Critical temperature rises larger than 30°C; immediate action is required to correct the issue

A.12 Power Transformers

DGA grading parameters for power transformers are derived from IEEE Standard C57.104[4].

Table A-35: Gas Concentration (ppm) limits

Gas	O2/N2 Ratio <= 0.2				O2/N2 Ratio >0.2			
	Transformer Age in Years				Transformer Age in Years			
	Unknown	1-9	10-30	>30	Unknown	1-9	10-30	>30
H_2	80	75		100	40	40		

[4] Transformers Committee of the IEEE Power and Energy Society, IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers (2019)

Gas	O2/N2 Ratio <= 0.2				O2/N2 Ratio >0.2			
	Transformer Age in Years				Transformer Age in Years			
	Unknown	1-9	10-30	>30	Unknown	1-9	10-30	>30
CH_4	90	45	90	110	20	20		
C_2H_6	90	30	90	150	15	15		
C_2H_4	50	20	50	90	50	25	60	
C_2H_2	1	1			2	2		
CO	900	900			500	500		
CO_2	9000	5000	10000		5000	3500	5500	

Table A-36: Gas Rate of Changes Limits (ppm)

Gas	Maximum (ppm) variation between consecutive DGA samples	
	O2/N2 Ratio <= 0.2	O2/N2 Ratio >0.2
H_2	40	25
CH_4	30	10
C_2H_6	25	7
C_2H_4	20	
C_2H_2	Any Increase	
CO	250	175

Gas	Maximum (ppm) variation between consecutive DGA samples	
	O2/N2 Ratio <= 0.2	O2/N2 Ratio >0.2
CO_2	2500	1750

Table A-37: Criteria for DGA Results

Condition Rating	Corresponding Condition
A	All parameters within acceptable limits
B	1 parameter does not meet acceptability limits.
C	2 parameters do not meet acceptability limits.
D	3 parameters do not meet acceptability limits.
E	4 or more parameters do not meet acceptability limits.

Table A-38: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table A-39: Criteria for Service Age (Power TX)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 50 years
E	More than 51 years

Table A-40: Criteria for Insulation Resistance

Condition Rating	Corresponding Condition

A	IR ≥ 5 GΩ
B	4.0 < IR ≤ 5.0 GΩ
C	2.5 < IR ≤ 4.0 GΩ
D	0.5 < IR ≤ 2.5 GΩ
E	0 < IR ≤ 0.5 GΩ

Table A-41: Criteria for Bushing Condition

Condition Rating	Corresponding Condition
A	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash, and copper wash. Cementing and fasteners are secure.
B	Bushings are not broken, but minor chips and cracks are visible. Cementing and fasteners are secure.
C	Bushings are not broken; however, major chips and some flashover burns, and copper splash are visible. Cementing and fasteners are secure.
D	Bushings are broken or cementing, and fasteners are not secure.
E	Bushings, cementing, or fasteners are broken/damaged beyond repair.

Table A-42: Criteria for Bushing Hot Collar Test

Condition Rating	Corresponding Condition
A	50 > Power Loss ≥ 0 mWatts
C	100 > Power Loss ≥ 50 mWatts

E	Power Loss ≥ 100 mWatts

Table A-43: Criteria for Bushing Power Factor Test

Condition Rating	Bushing PF % Deviation
A	0 ≤ % Deviation ≤ 1.25
B	1.25 < % Deviation ≤ 1.5
C	1.5 < % Deviation ≤ 1.75
D	1.75 < % Deviation ≤ 2
E	2 < % Deviation

Table A-44: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table A-45: Criteria for Turns Test Ratio

Condition Rating	Corresponding Condition
A	Maximum Deviation: 0-0.09%

B	0.10-0.29%
C	0.03-0.39%
D	0.40-0.49%
E	≥ 0.5%

Table A-46: Criteria for DC Winding Resistance Testing

Condition Rating	Corresponding Condition
A	0-0.49%
B	0.50-2.49%
C	2.5-3.99%
D	4.0-4.99%
E	≥ 5%

Table A-47: Criteria for Concrete Pad Condition

Condition Rating	Corresponding Condition
B	Normal signs of wear with respect to the transformer concrete pad. Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion.
C	One of the above characteristics is unacceptable.
D	Two of the above characteristics are unacceptable.

Table A-48: Criteria for Oil Leaks

Condition Rating	Corresponding Condition
B	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
C	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts.
D	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.

Table A-49: Criteria for Cooling Fan Equipment and Control

Condition Rating	Corresponding Condition
B	Normal signs of wear with respect to rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position. Pump bearings are in good condition and fan controls are operating per design.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable. Fan and pump enclosures may be damaged/degraded beyond repair.

Table A-50: Criteria for Visual Condition (Power TX)

Condition Rating	Corresponding Condition
B	Good
C	Fair
D	Poor

A.13 Circuit Breakers and Reclosers

Table A-51: Criteria for Service Age (Circuit Breakers/Reclosers)

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	61 years or older

Electrical testing for circuit breaker and reclosers considers both insulation resistance and contact resistance. Both grading schemes are below.

Table A-52: Criteria for Insulation Resistance Testing

Condition Rating	Corresponding Condition
A	400%+ Min Resistance (based on ANSI/NETA MTS Table 100.1)
B	[300%-400%) Min Resistance
C	[200%-300%) Min Resistance
D	[100%-200%) Min Resistance
E	<100% Min Resistance

Table A-53: Criteria for Contact Resistance Testing

Condition Rating	Corresponding Condition
Final contact resistance score is the worst score of (1) and (2): (1) % Deviation from pole with lowest contact resistance to highest contact resistance (2) % Deviation between breakers of same make, model, and installation year	
A	[0%-10%]
B	(10%-25%]
C	(25%-40%]
D	(40%-50%]
E	>50%

Table A-54: Criteria for Visual Inspection (Circuit Breakers/Reclosers)

Condition Rating	Component Condition
A	All components are clean; corrosion and leak free and are in good condition. No external evidence of overheating, deterioration or abnormality or damage. No wear and tear noticeable.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.

Condition Rating	Component Condition
E	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table A-55: Criteria for Functional Obsolescence

Condition Rating	Corresponding Condition
A	No functional obsolescence issues with this type or manufacturer of Station Circuit Breaker
E	The Station Circuit Breaker is functionally obsolescent (e.g., by type or manufacturer)

A.14 Station Switches

Table A-56: Criteria for Overall Condition (Station Switches)

Condition Rating	Corresponding Condition
A	Switch is in relatively new condition
C	Switch has some minor defects
E	Switch has some significant defects

Table A-57: Criteria for Contact Resistance

Condition Rating	Corresponding Condition
A	0 μΩ ≤ Resistance < 175μΩ
B	175 μΩ ≤ Resistance < 200μΩ
C	200 μΩ ≤ Resistance < 250μΩ
D	250 μΩ ≤ Resistance < 300μΩ
E	Resistance ≥ 300μΩ

Table A-58: Criteria for Service Age (Station Switches)

Condition Rating	Corresponding Condition
A	0 to 9 years
B	10 to 19 years
C	20 to 29 years
D	30 to 39 years
E	40 years or more

A.15 Station Batteries

Table A-59: Criteria for Service Age (Station Batteries)

Condition Rating	Corresponding Condition
A	0-5 Years
B	6-10 Years
C	11-15 Years
D	16-20 Years
E	More than 20 years

Table A-60: Criteria for Battery Voltage Testing

Condition Rating	Corresponding Condition
A	Battery voltage/nominal voltage ratio >= 1
C	Battery voltage/nominal voltage ratio is in the interval [0.8, 1)
E	Battery voltage/nominal voltage ratio is in the interval [0, 0,8)

Table A-61: Criteria for Battery Bank Condition

Condition Rating	Component Condition
A	Overall installation is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating or any other abnormality. Appears to have been well maintained.
B	Normal signs of wear with respect to the above characteristics.

Condition Rating	Component Condition
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

A.16 Station Chargers

Table A-62: Criteria for Charger Condition

Condition Rating	Component Condition
A	All components are clean; corrosion and leak free and are in good condition. No external evidence of overheating, deterioration or abnormality or damage. No wear and tear noticeable.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

A.17 Station Relays

Table A-63: Criteria for Service Age (Station Relays)

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-64: Criteria for Protective Relay Testing

Condition Rating	Corresponding Condition
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
D	Not possible to calibrate the relays to bring settings to specified limits

Table A-65: Criteria for Overall Condition (Station Relays)

Condition Rating	Component Condition
A	All components are clean; corrosion and leak free and are in good condition. No external evidence of overheating, deterioration or abnormality or damage. No wear and tear noticeable.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

A.18 Station Cables

Table A-66: Criteria for Service Age (Station Cables)

Condition Rating	Corresponding Condition
A	0 to 8 years
B	9 to 16 years
C	17 to 25 years
D	26 to 33 years
E	34 years or older

Table A-67: Criteria for Loading History

Condition Rating	Corresponding Condition
A	0 to 50% loaded
B	50 to 70% loaded
C	70 to 90% loaded
D	90 to 100% loaded
E	More than 100% loaded

Table A-68: Criteria for Insulation Resistance (5 kV)

Condition Rating	Corresponding Condition
A	IR ≥ 1.5 GΩ
B	1.25 < IR ≤ 1.5 GΩ
C	0.75 < IR ≤ 1.25 GΩ
D	0.15 < IR ≤ 0.75 GΩ
E	0 < IR ≤ 0.15 GΩ

Table A-69: Criteria for Insulation Resistance (15 kV)

Condition Rating	Corresponding Condition
A	IR ≥ 5.0 GΩ
B	4.0 < IR ≤ 5.0 GΩ

Condition Rating	Corresponding Condition
C	2.5 < IR ≤ 4.0 GΩ
D	0.5 < IR ≤ 2.5 GΩ
E	0 < IR ≤ 0.5 GΩ

Table A-70: Criteria for Insulation Resistance (44 kV)

Condition Rating	Corresponding Condition
A	IR ≥ 100 GΩ
B	80 < IR ≤ 100 GΩ
C	50 < IR ≤ 80 GΩ
D	10 < IR ≤ 50 GΩ
E	0 < IR ≤ 10 GΩ

A.19 Station Buildings

Table A-71: Visual Criteria for Station Buildings

Condition Rating	Component Condition
A	Good - Clean and free from signs of deterioration. Paint on surfaces clean and free from cracking, discoloration or flaking/pealing. Structural elements straight and level. Building properly sealed and no leaks present.
C	Fair - One or two of the above characteristics are unacceptable. Minor maintenance suggested.

E	Poor - More than two of the above characteristics are unacceptable. Significant maintenance or repair is required.

A.20 Station Fences

Table A-72: Visual Criteria for Station Fences

Condition Rating	Corresponding Condition
A	Good - No deficiencies
C	Fair - Only minor deficiencies
E	Poor - Major deficiencies requiring immediate attention

A.21 Station Switchgears

Table A-73: Criteria for Service Age (Station Switchgears)

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	54 years or older

Table A-74: Criteria for Visual Condition of Station Switchgears

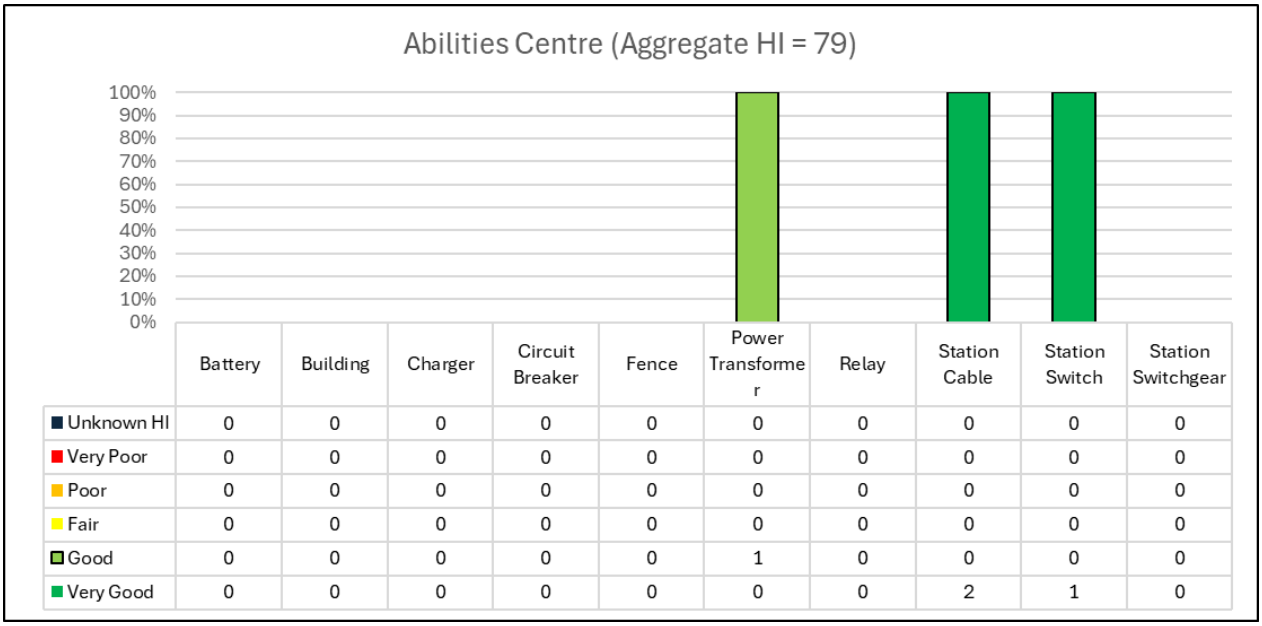
Condition Rating	Corresponding Condition
A	Good - No deficiencies
C	Fair - Only minor deficiencies
E	Poor - Major deficiencies requiring immediate attention

Table A-75: Criteria for Insulation Resistance Test

Condition Rating	Corresponding Condition
A	400%+ Min Resistance (based on ANSI/NETA MTS Table 100.1)
B	[300%-400%) Min Resistance
C	[200%-300%) Min Resistance
D	[100%-200%) Min Resistance
E	<100% Min Resistance

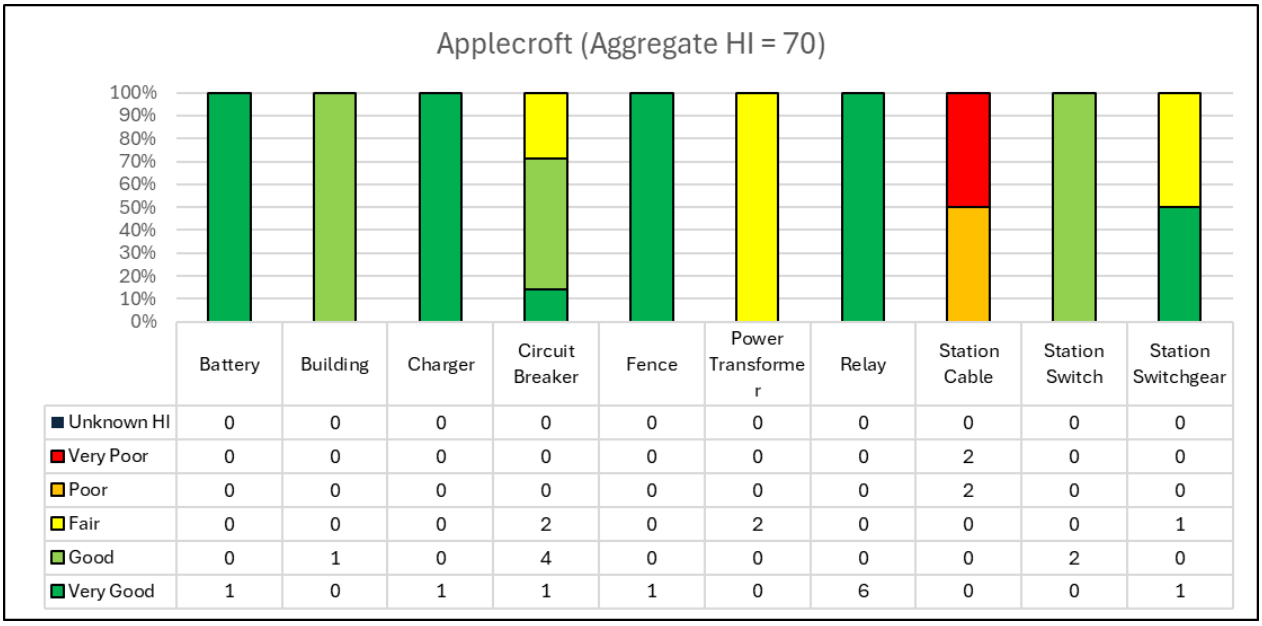
Appendix B: HI Results by Station

The following graphs show the HI breakdown by station for assets at each station. Included in the figure titles are Aggregate HI Scores, which represent an HI score for the overall station.



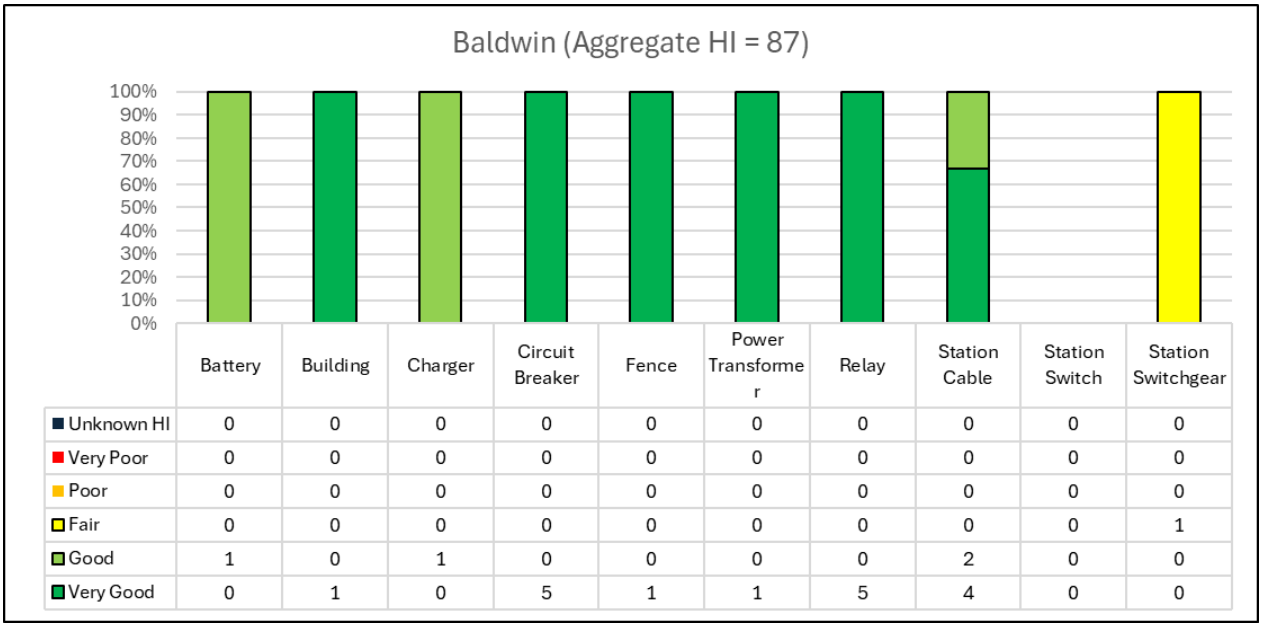
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	0	0	0	0	0	0	0	2	1	0

Figure B-1: HI Results at Abilities Centre



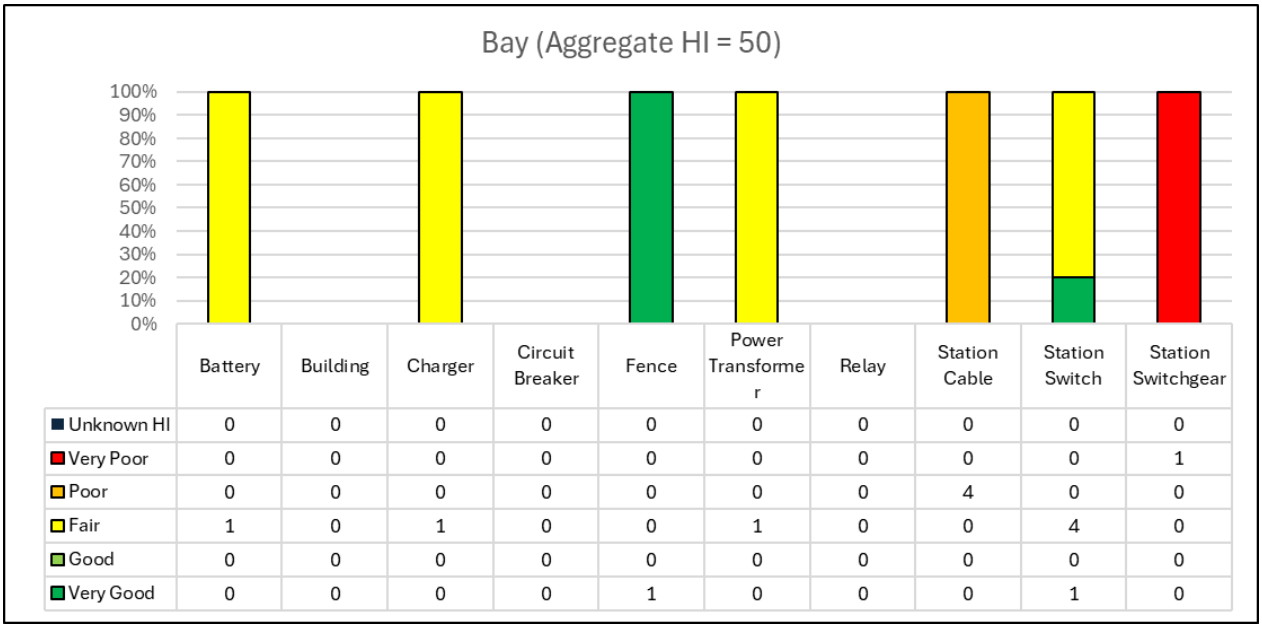
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	2	0	0
Poor	0	0	0	0	0	0	0	2	0	0
Fair	0	0	0	2	0	2	0	0	0	1
Good	0	1	0	4	0	0	0	0	2	0
Very Good	1	0	1	1	1	0	6	0	0	1

Figure B-2: HI Results at Applecroft



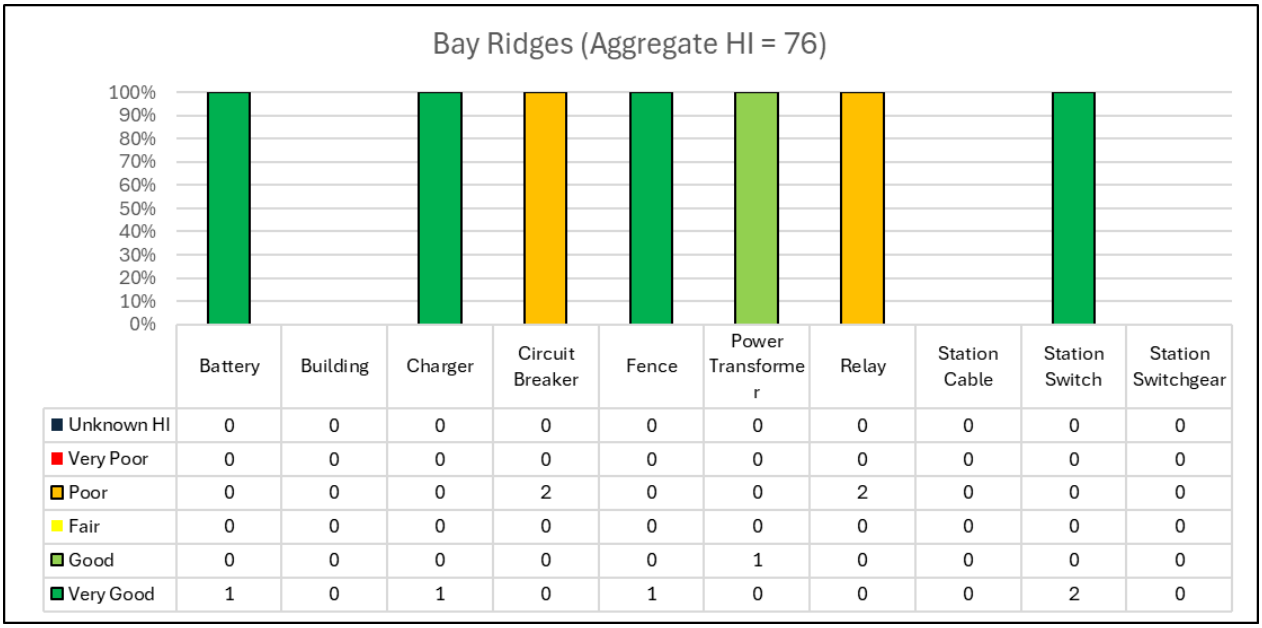
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	0	1
Good	1	0	1	0	0	0	0	2	0	0
Very Good	0	1	0	5	1	1	5	4	0	0

Figure B-3: HI Results at Baldwin



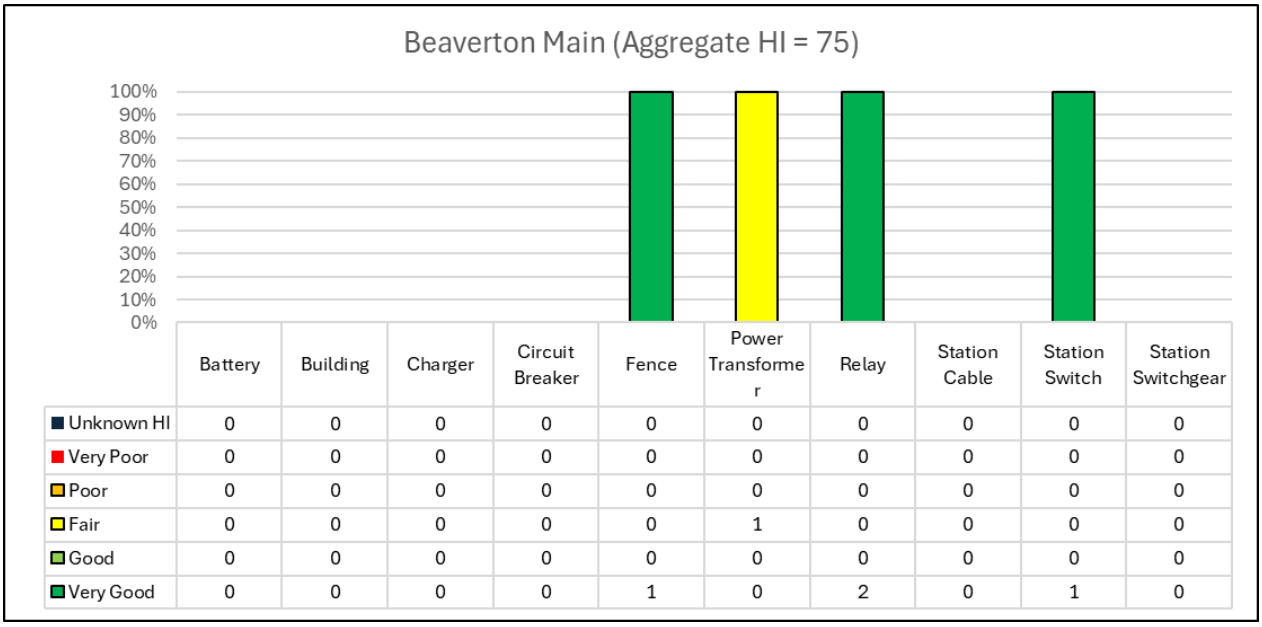
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	1
Poor	0	0	0	0	0	0	0	4	0	0
Fair	1	0	1	0	0	1	0	0	4	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	0	0	1	0

Figure B-4: HI Results at Bay



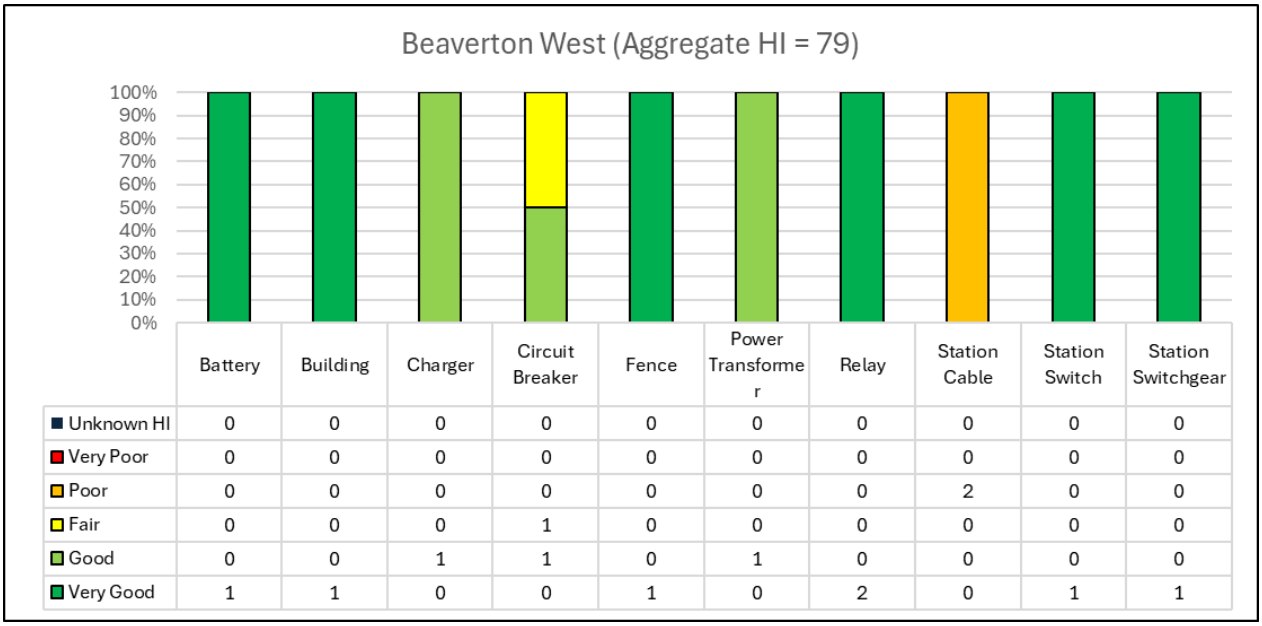
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	2	0	0	2	0	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	1	0	1	0	1	0	0	0	2	0

Figure B-5: HI Results at Bay Ridges



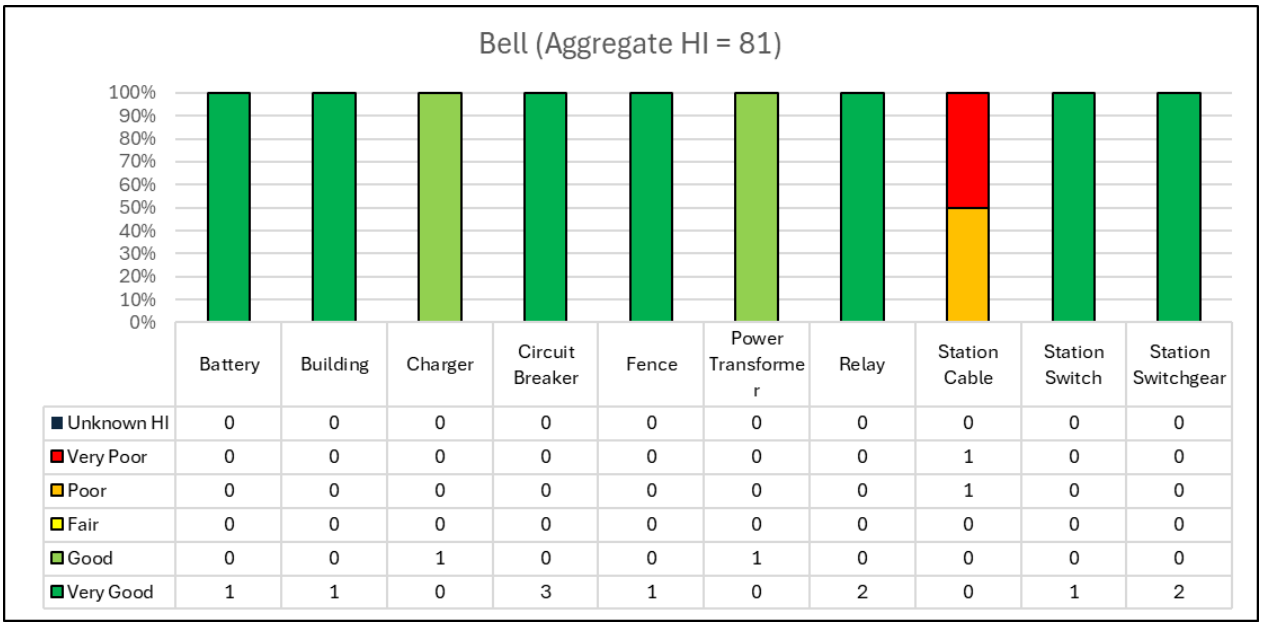
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	0	0	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	2	0	1	0

Figure B-6: HI Results at Beaverton Main



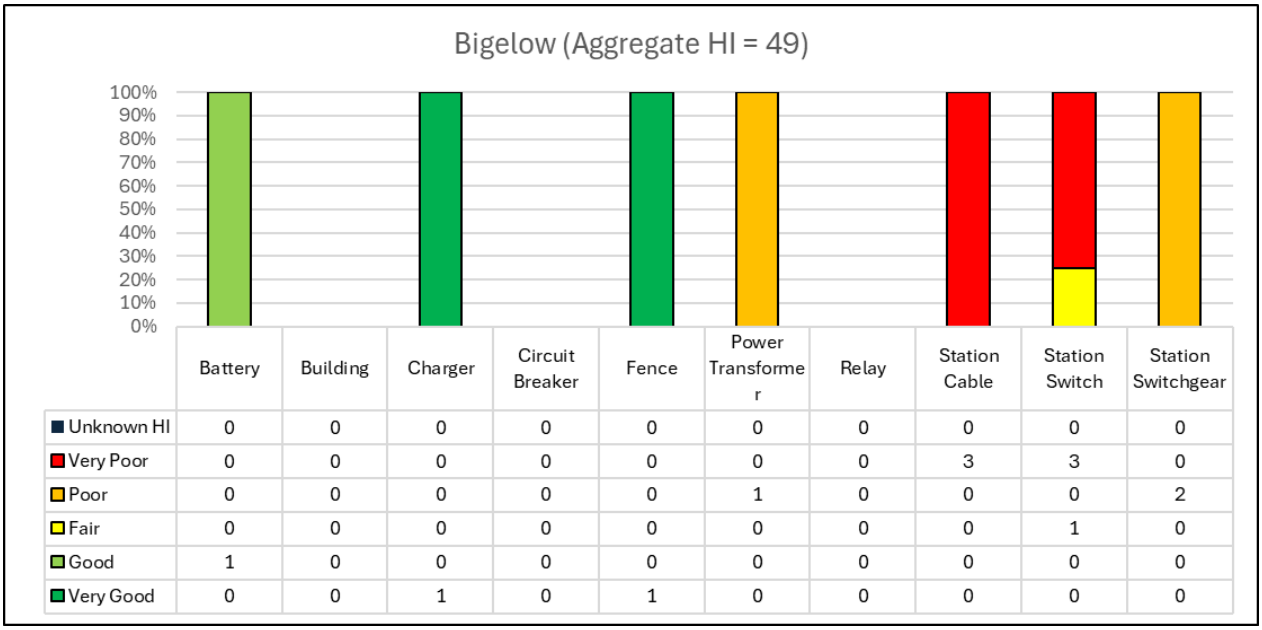
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	2	0	0
Fair	0	0	0	1	0	0	0	0	0	0
Good	0	0	1	1	0	1	0	0	0	0
Very Good	1	1	0	0	1	0	2	0	1	1

Figure B-7: HI Results at Beaverton West



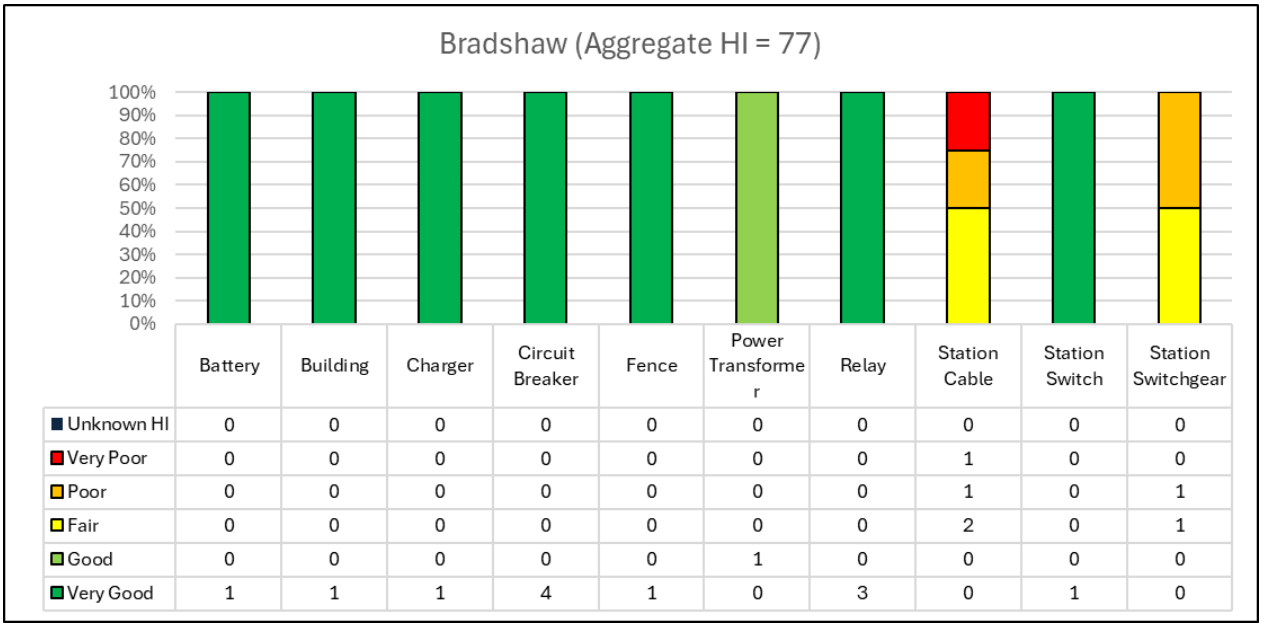
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	1	0	0	1	0	0	0	0
Very Good	1	1	0	3	1	0	2	0	1	2

Figure B-8: HI Results at Bell



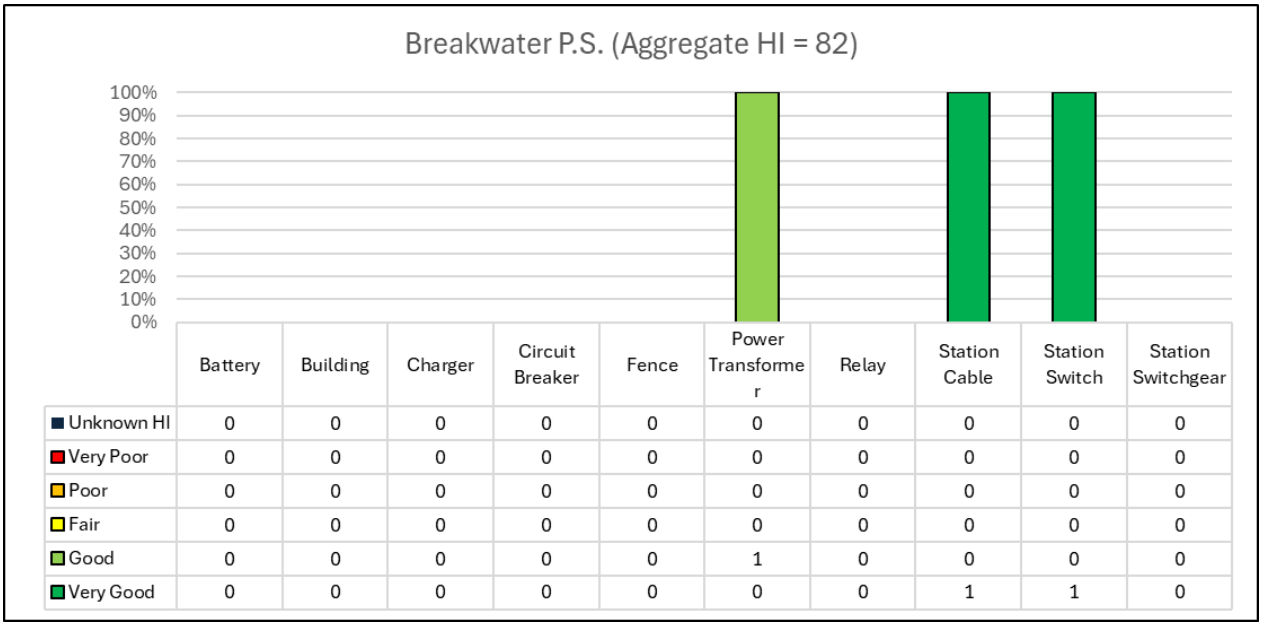
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	3	3	0
Poor	0	0	0	0	0	1	0	0	0	2
Fair	0	0	0	0	0	0	0	0	1	0
Good	1	0	0	0	0	0	0	0	0	0
Very Good	0	0	1	0	1	0	0	0	0	0

Figure B-9: HI Results at Bigelow



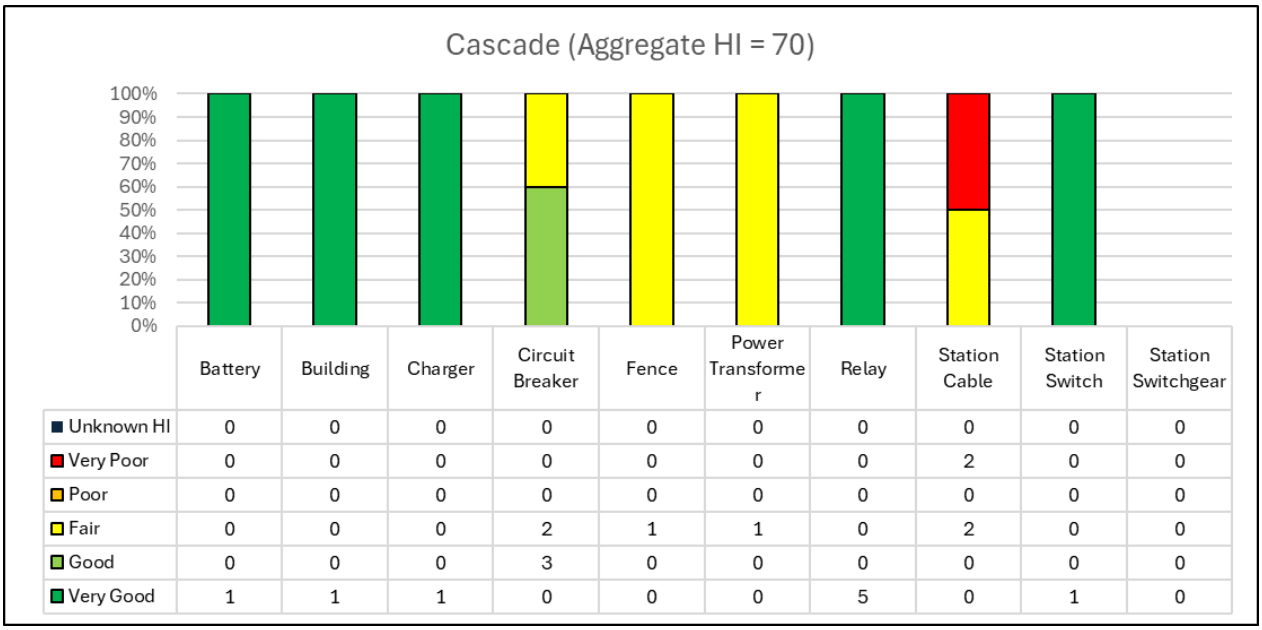
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	1
Fair	0	0	0	0	0	0	0	2	0	1
Good	0	0	0	0	0	1	0	0	0	0
Very Good	1	1	1	4	1	0	3	0	1	0

Figure B-10: HI Results at Bradshaw



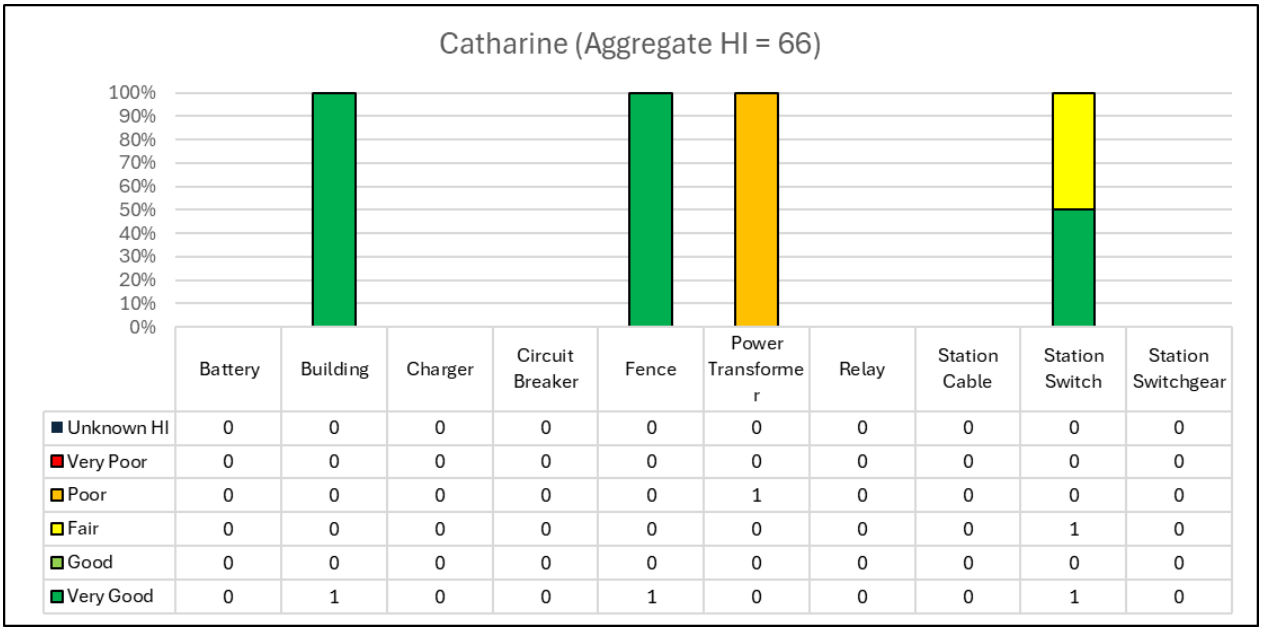
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	0	0	0	0	0	0	0	1	1	0

Figure B-11: HI Results at Breakwater P.S.



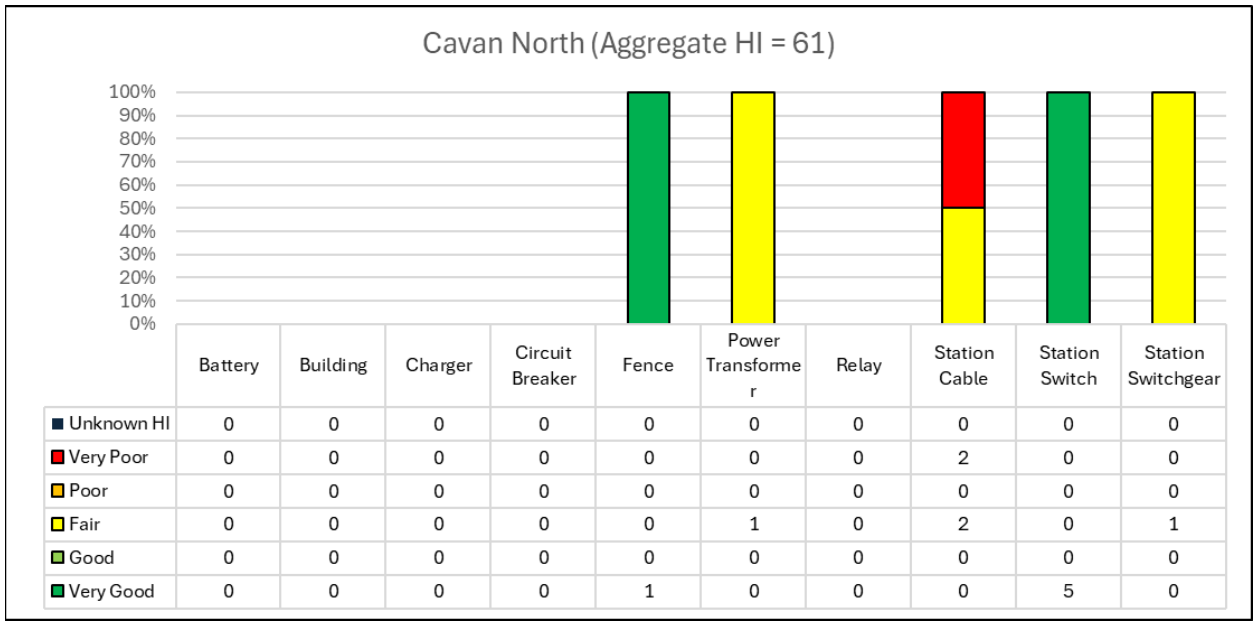
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	2	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	2	1	1	0	2	0	0
Good	0	0	0	3	0	0	0	0	0	0
Very Good	1	1	1	0	0	0	5	0	1	0

Figure B-12: HI Results at Cascade



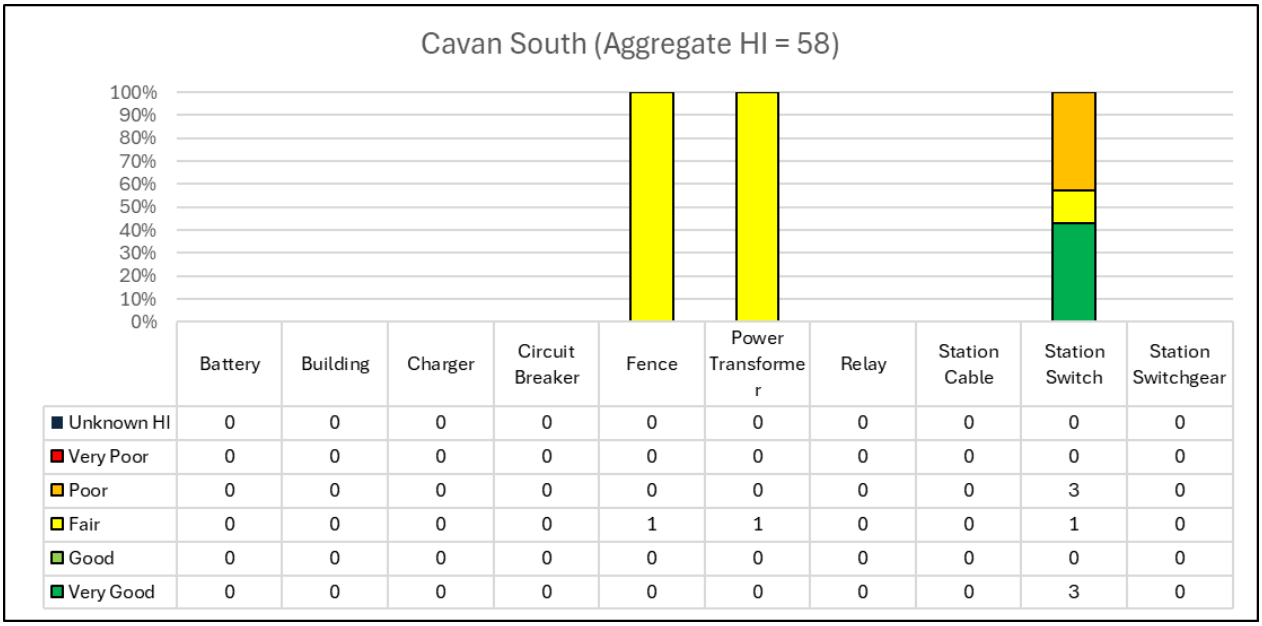
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	1	0	0	0	0
Fair	0	0	0	0	0	0	0	0	1	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	1	0	0	1	0	0	0	1	0

Figure B-13: HI Results at Catherine



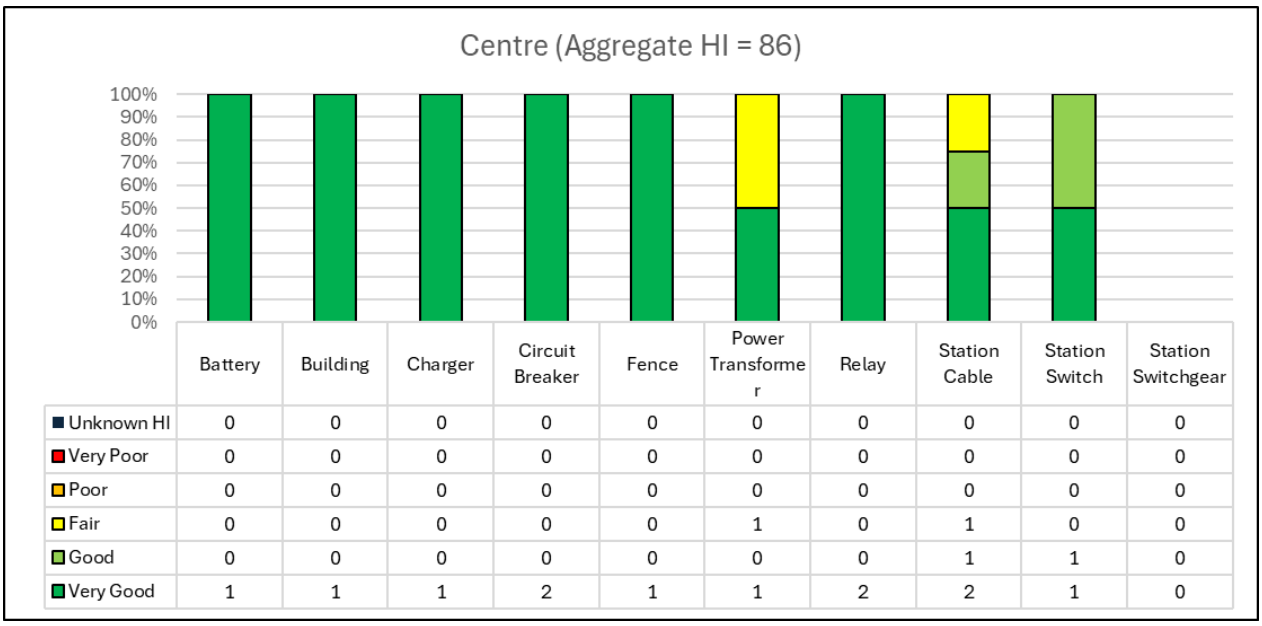
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	2	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	2	0	1
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	0	0	5	0

Figure B-14: HI Results at Cavan North



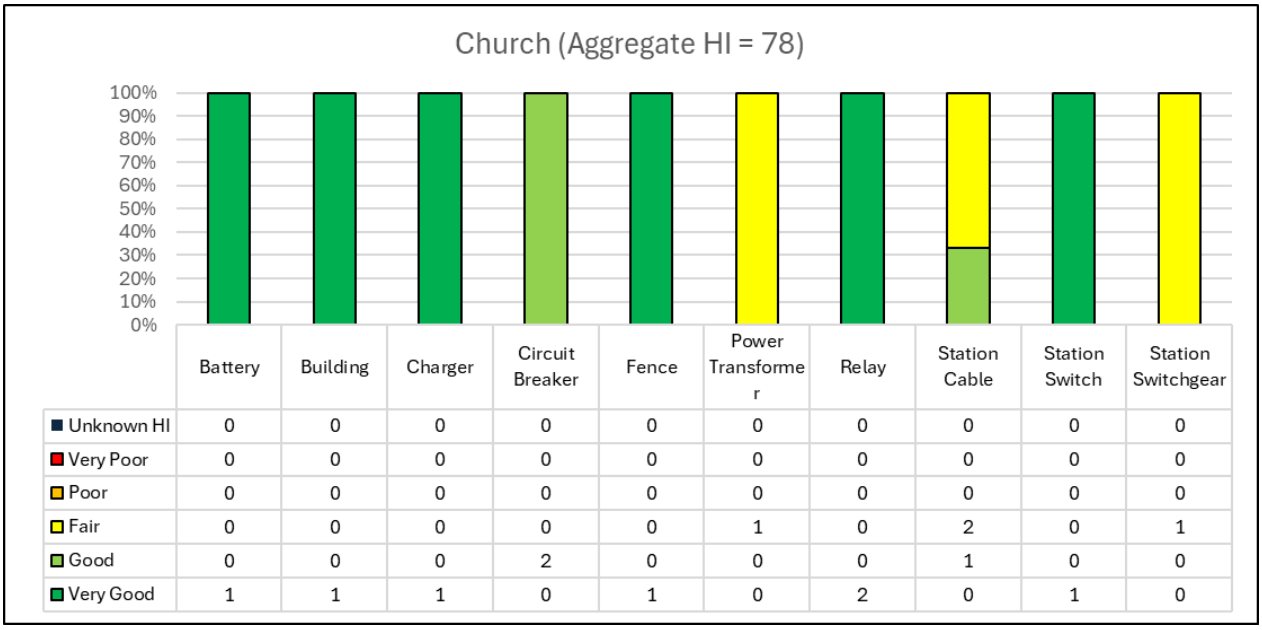
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	3	0
Fair	0	0	0	0	1	1	0	0	1	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	0	0	0	0	3	0

Figure B-15: HI Results at Cavan South



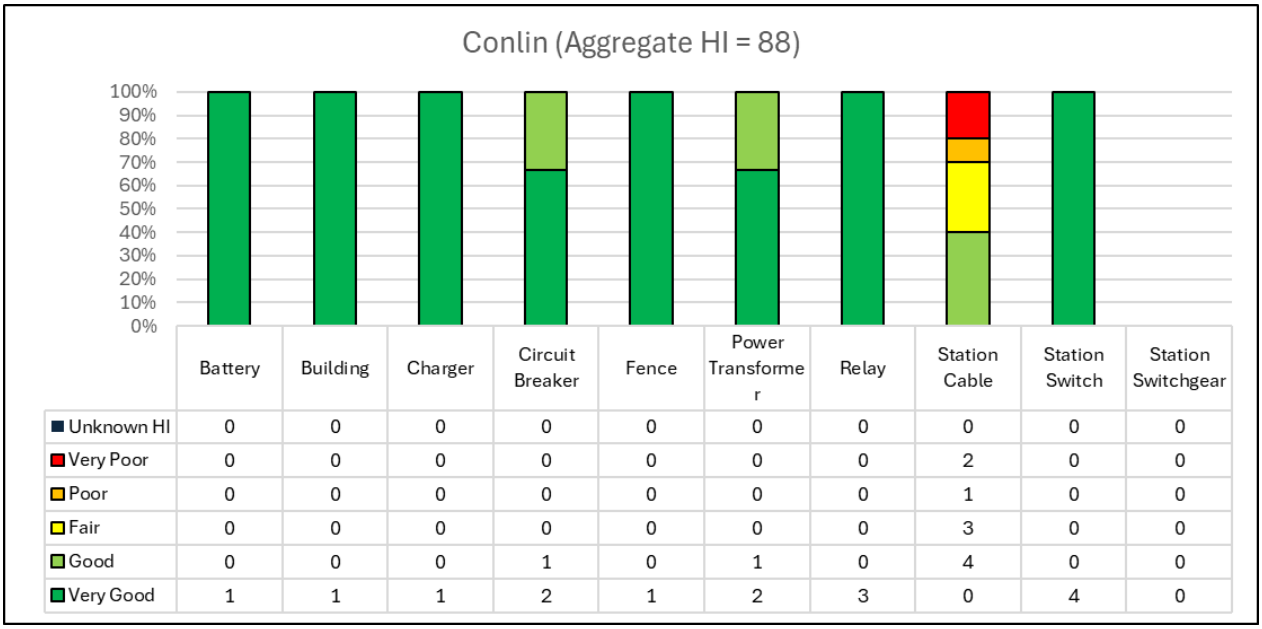
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	1	0	0
Good	0	0	0	0	0	0	0	1	1	0
Very Good	1	1	1	2	1	1	2	2	1	0

Figure B-16: HI Results at Centre



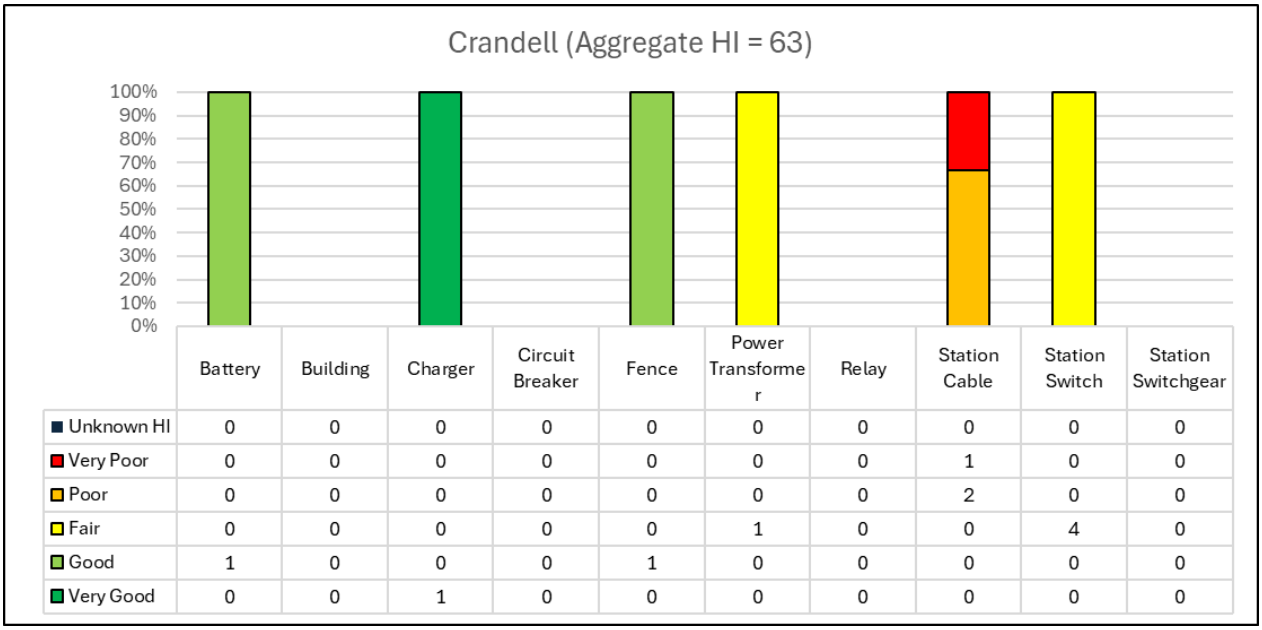
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	2	0	1
Good	0	0	0	2	0	0	0	1	0	0
Very Good	1	1	1	0	1	0	2	0	1	0

Figure B-17: HI Results at Church



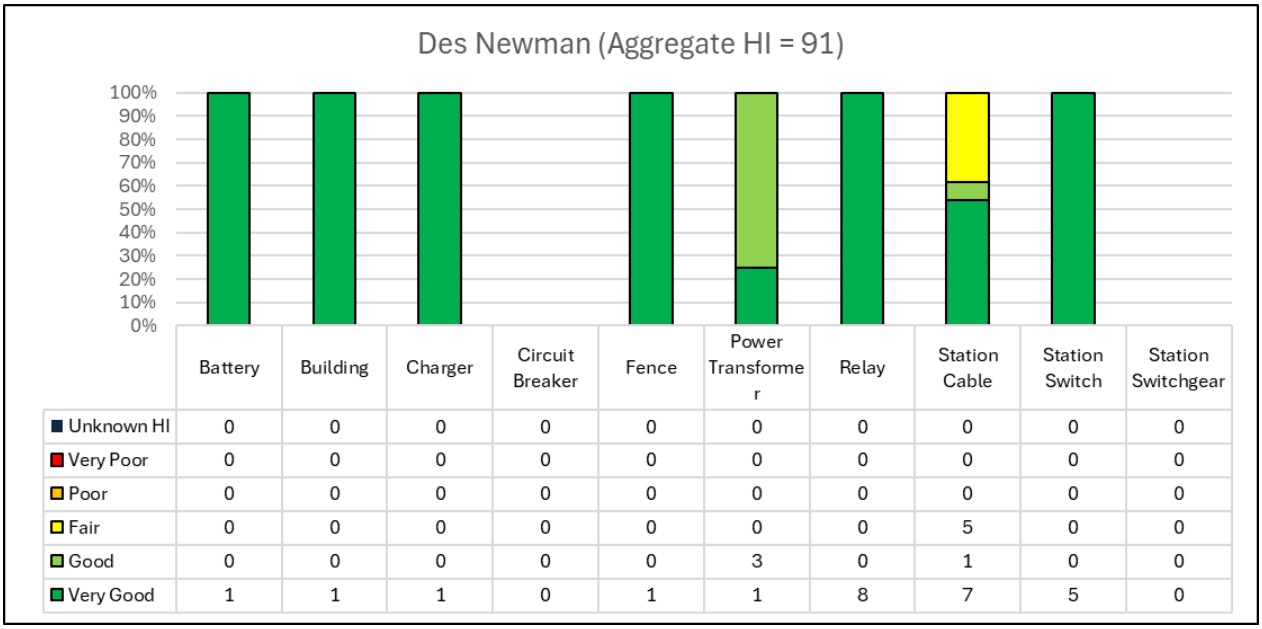
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	2	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	0	0	0	3	0	0
Good	0	0	0	1	0	1	0	4	0	0
Very Good	1	1	1	2	1	2	3	0	4	0

Figure B-18: HI Results at Conlin



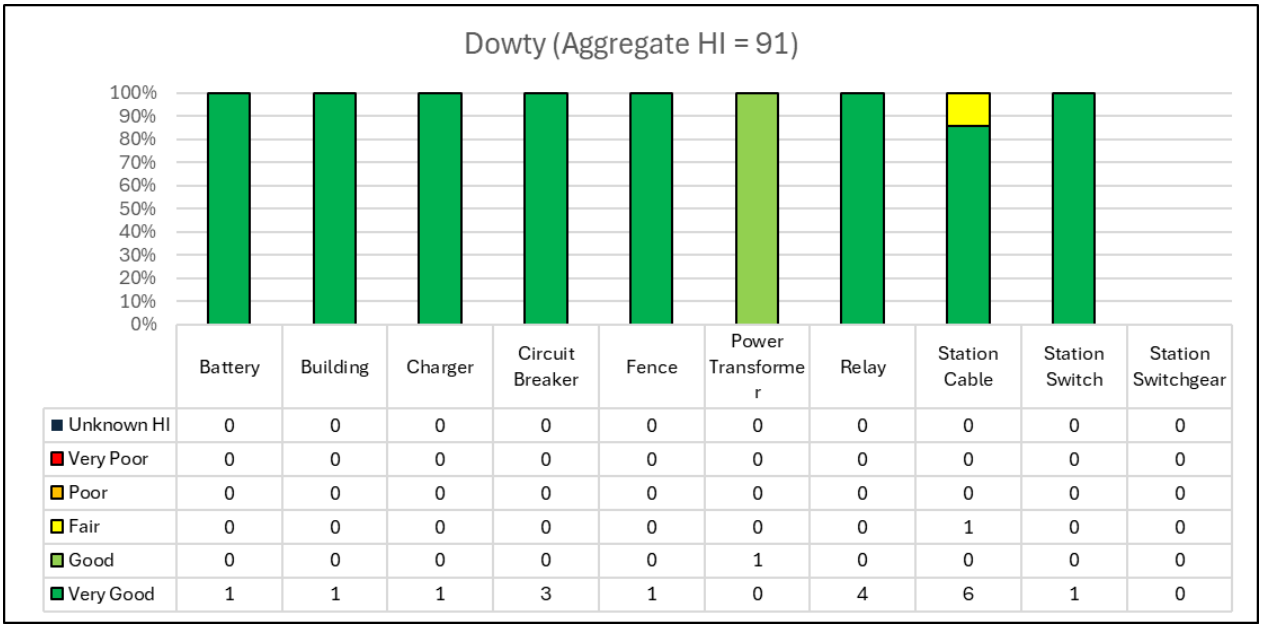
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	2	0	0
Fair	0	0	0	0	0	1	0	0	4	0
Good	1	0	0	0	1	0	0	0	0	0
Very Good	0	0	1	0	0	0	0	0	0	0

Figure B-19: HI Results at Crandell



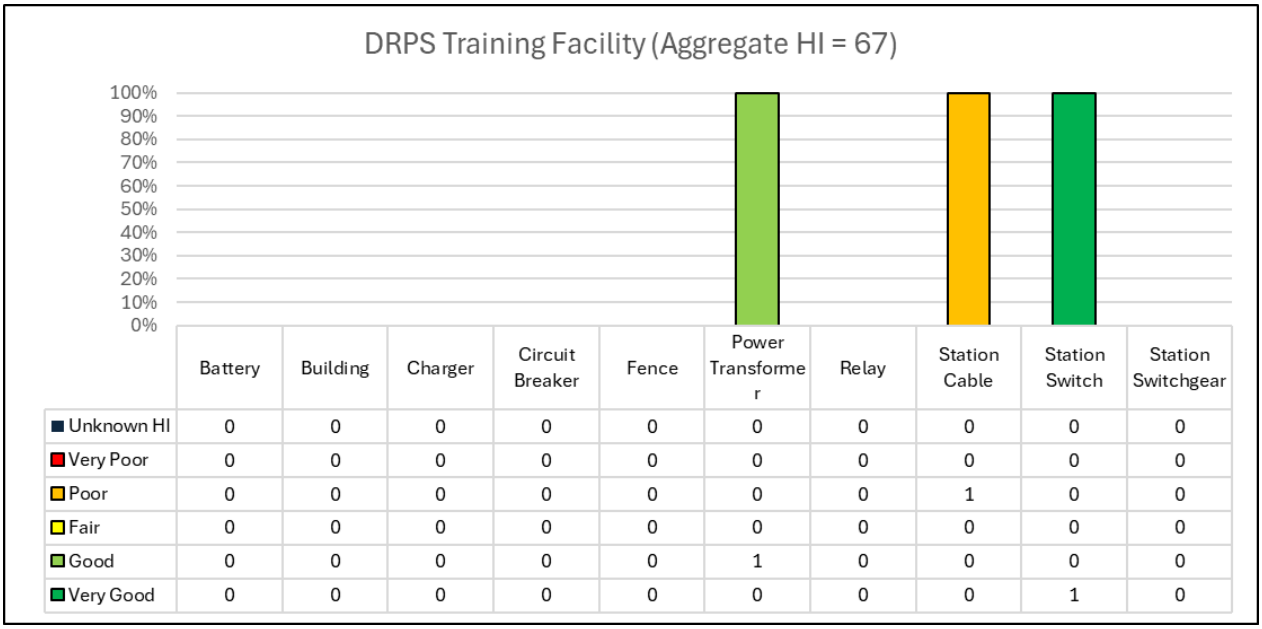
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	5	0	0
Good	0	0	0	0	0	3	0	1	0	0
Very Good	1	1	1	0	1	1	8	7	5	0

Figure B-20: HI Results at Des Newman



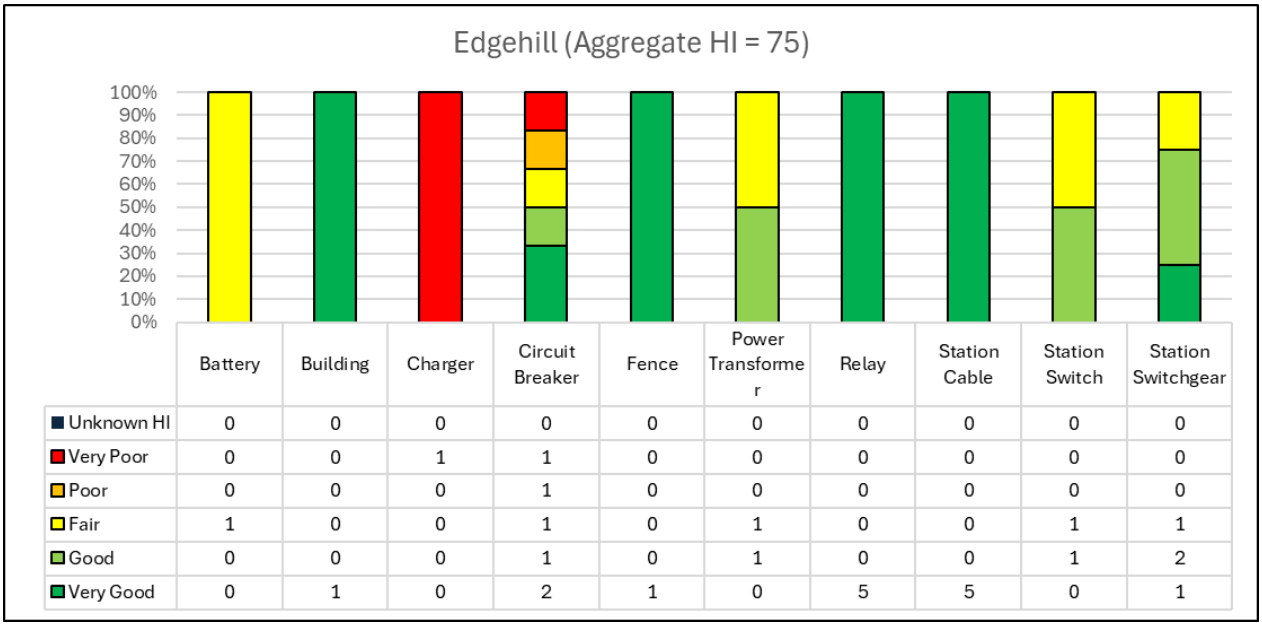
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	1	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	1	1	1	3	1	0	4	6	1	0

Figure B-21: HI Results at Dowty



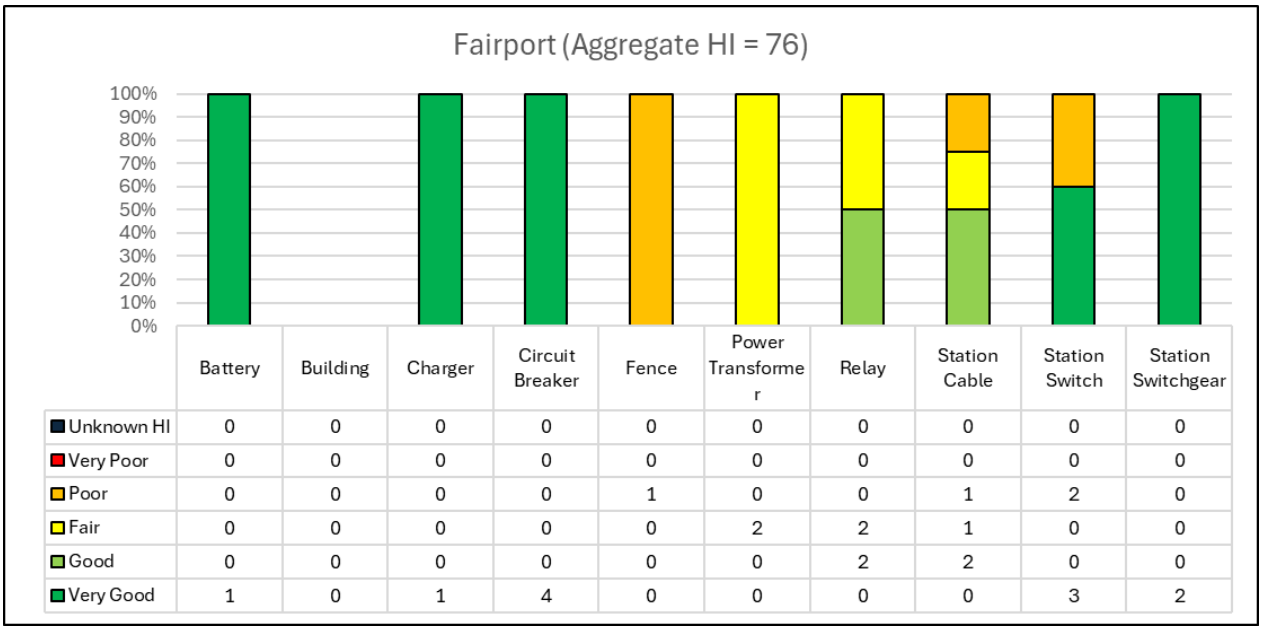
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	0	0	0	0	0	0	0	0	1	0

Figure B-22: HI Results at DRPS Training Facility



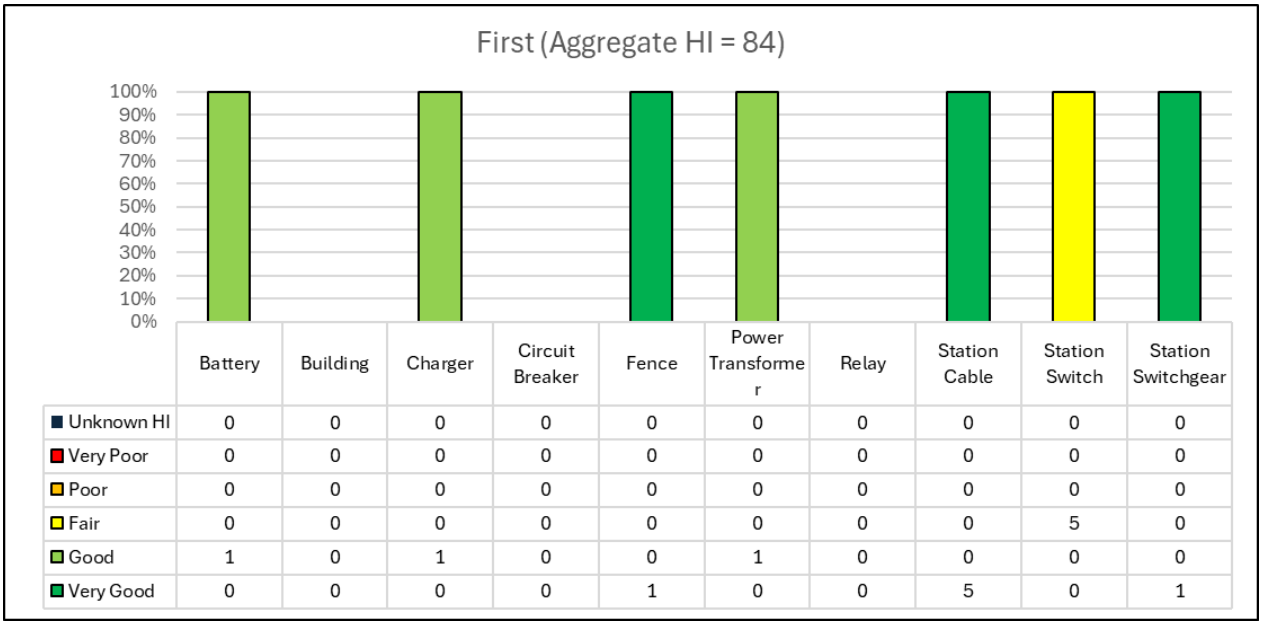
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	1	1	0	0	0	0	0	0
Poor	0	0	0	1	0	0	0	0	0	0
Fair	1	0	0	1	0	1	0	0	1	1
Good	0	0	0	1	0	1	0	0	1	2
Very Good	0	1	0	2	1	0	5	5	0	1

Figure B-23: HI Results at Edgehill



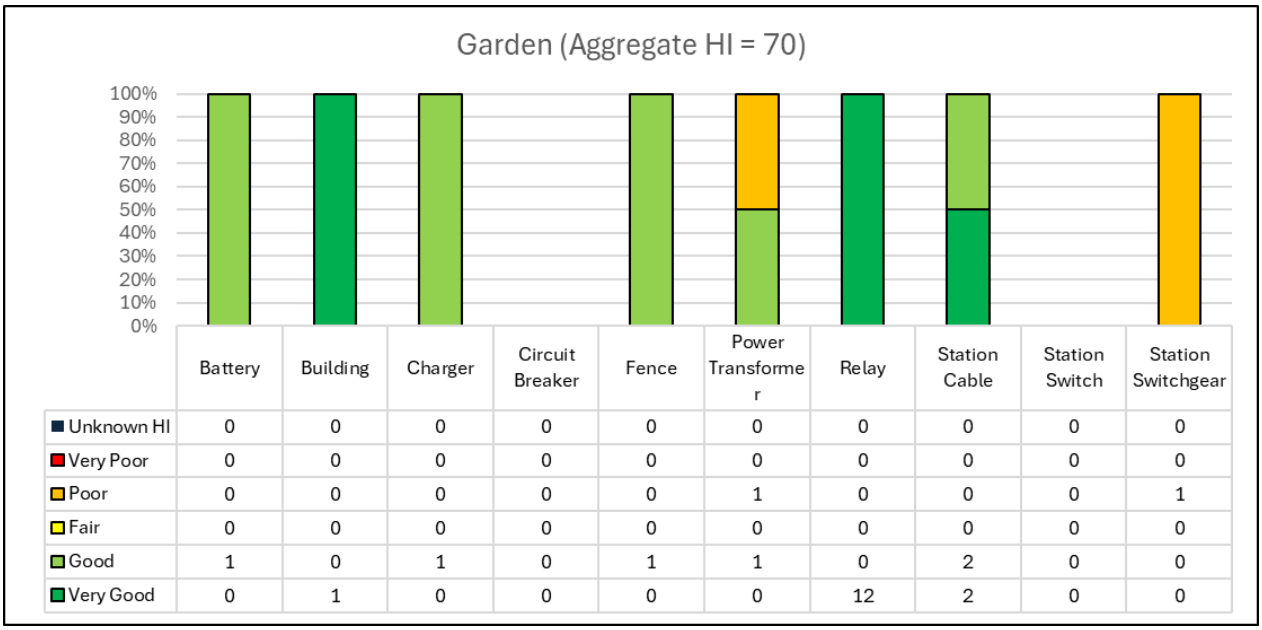
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	1	0	0	1	2	0
Fair	0	0	0	0	0	2	2	1	0	0
Good	0	0	0	0	0	0	2	2	0	0
Very Good	1	0	1	4	0	0	0	0	3	2

Figure B-24: HI Results at Fairport



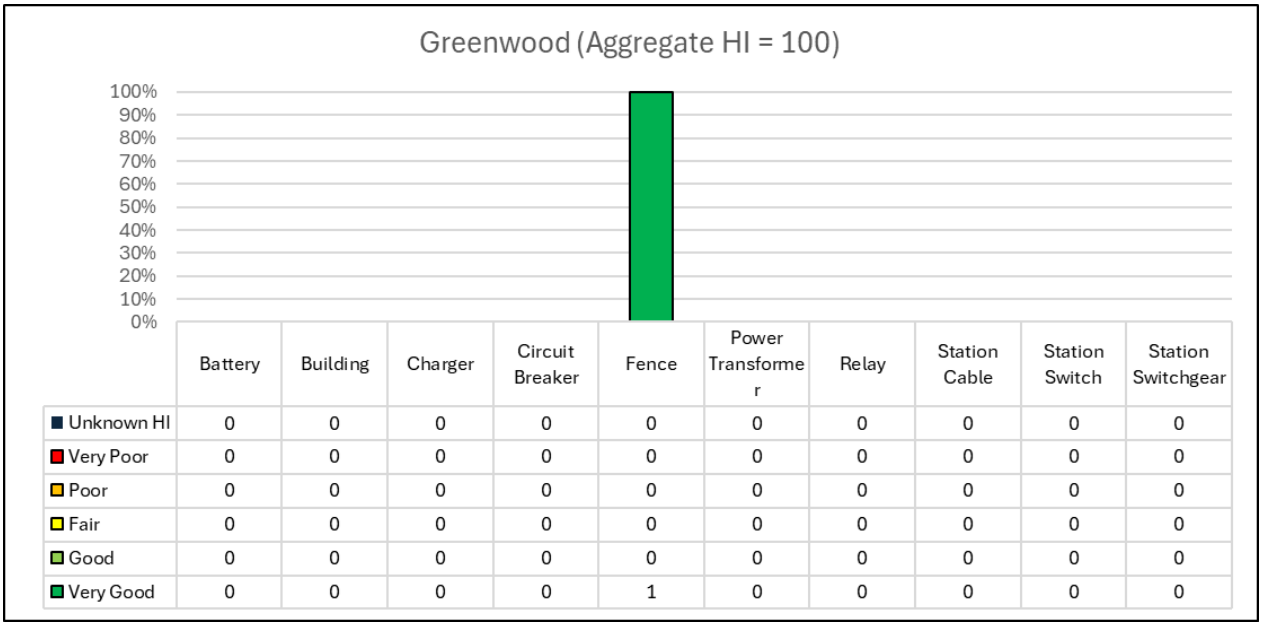
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	5	0
Good	1	0	1	0	0	1	0	0	0	0
Very Good	0	0	0	0	1	0	0	5	0	1

Figure B-25: HI Results at First



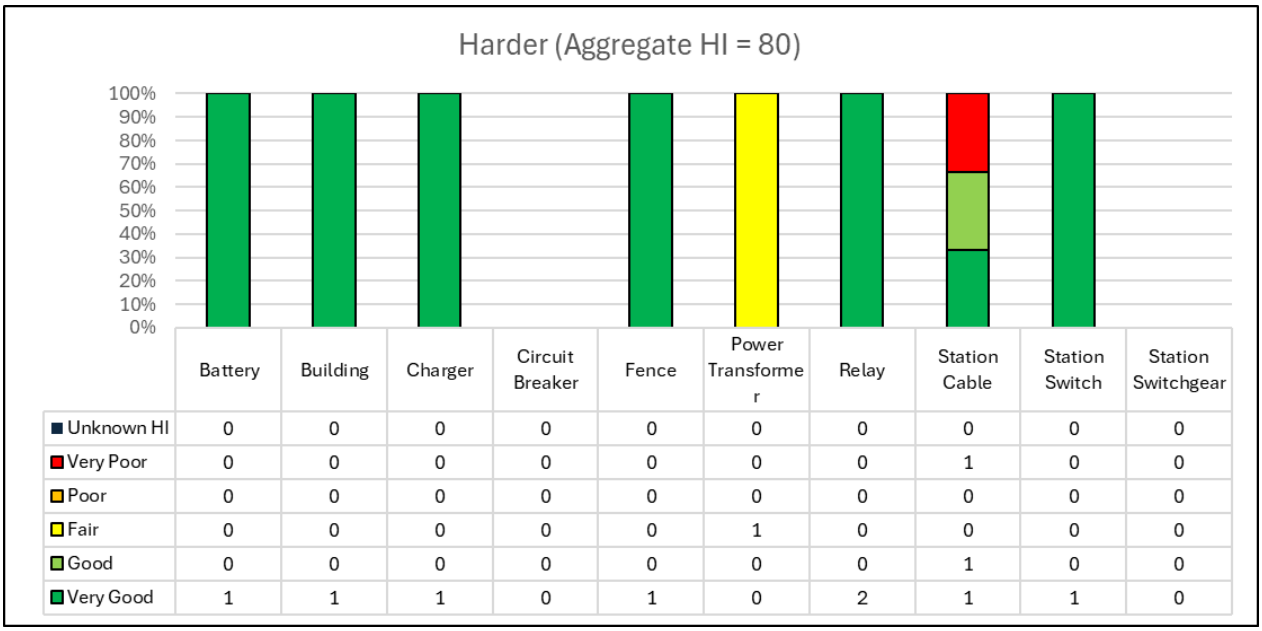
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	1	0	0	0	1
Fair	0	0	0	0	0	0	0	0	0	0
Good	1	0	1	0	1	1	0	2	0	0
Very Good	0	1	0	0	0	0	12	2	0	0

Figure B-26: HI Results at Garden



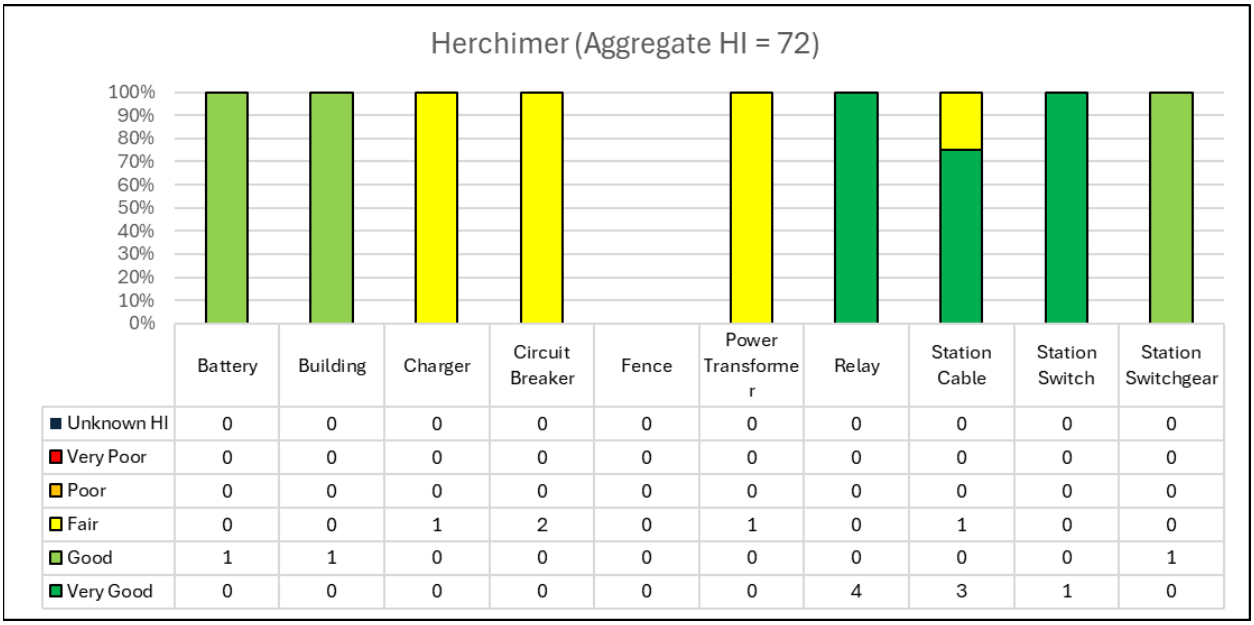
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	0	0	0	0

Figure B-27: HI Results at Greenwood



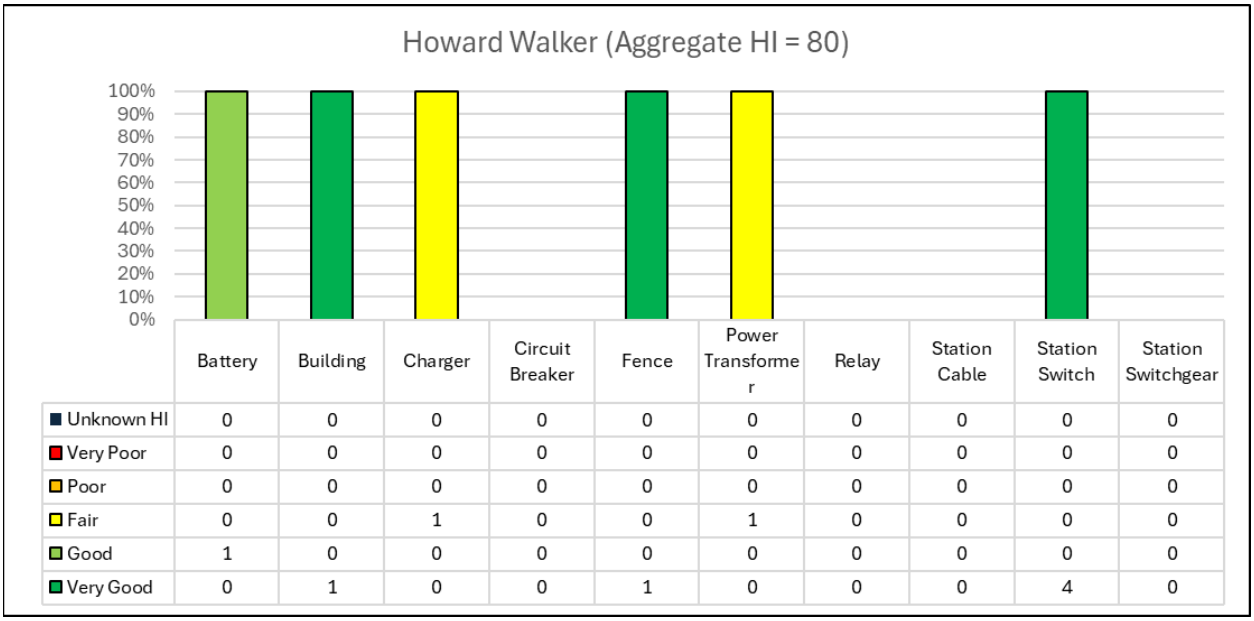
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	0	0	0
Good	0	0	0	0	0	0	0	1	0	0
Very Good	1	1	1	0	1	0	2	1	1	0

Figure B-28: HI Results at Harder



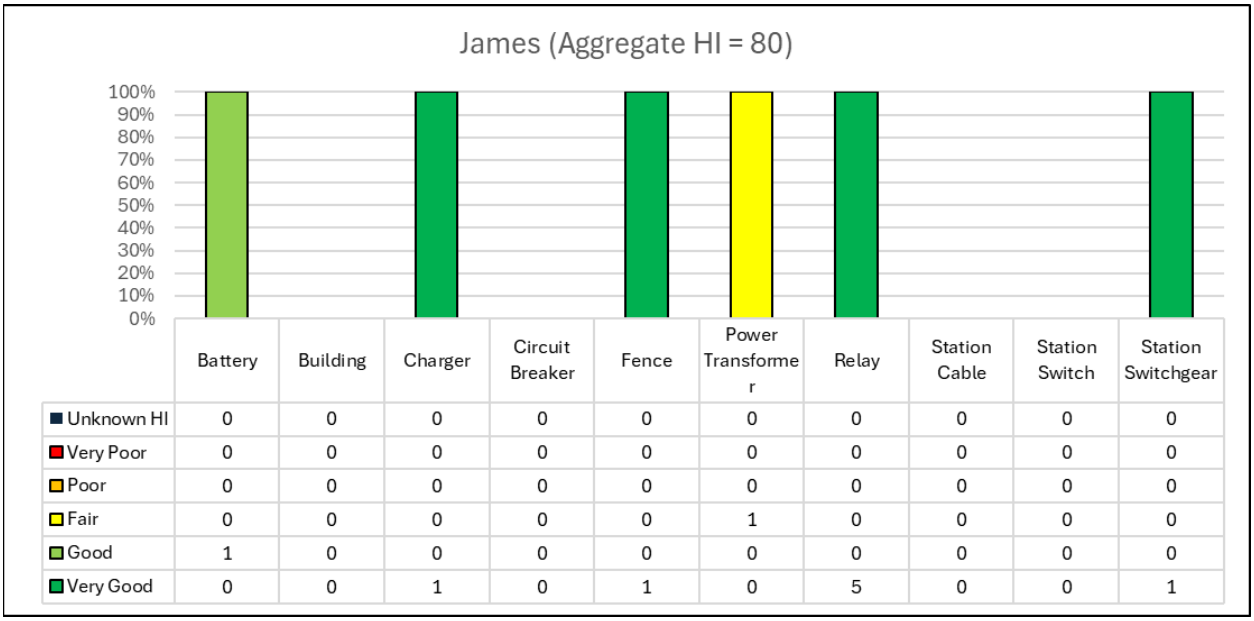
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	1	2	0	1	0	1	0	0
Good	1	1	0	0	0	0	0	0	0	1
Very Good	0	0	0	0	0	0	4	3	1	0

Figure B-29: HI Results at Herchimer



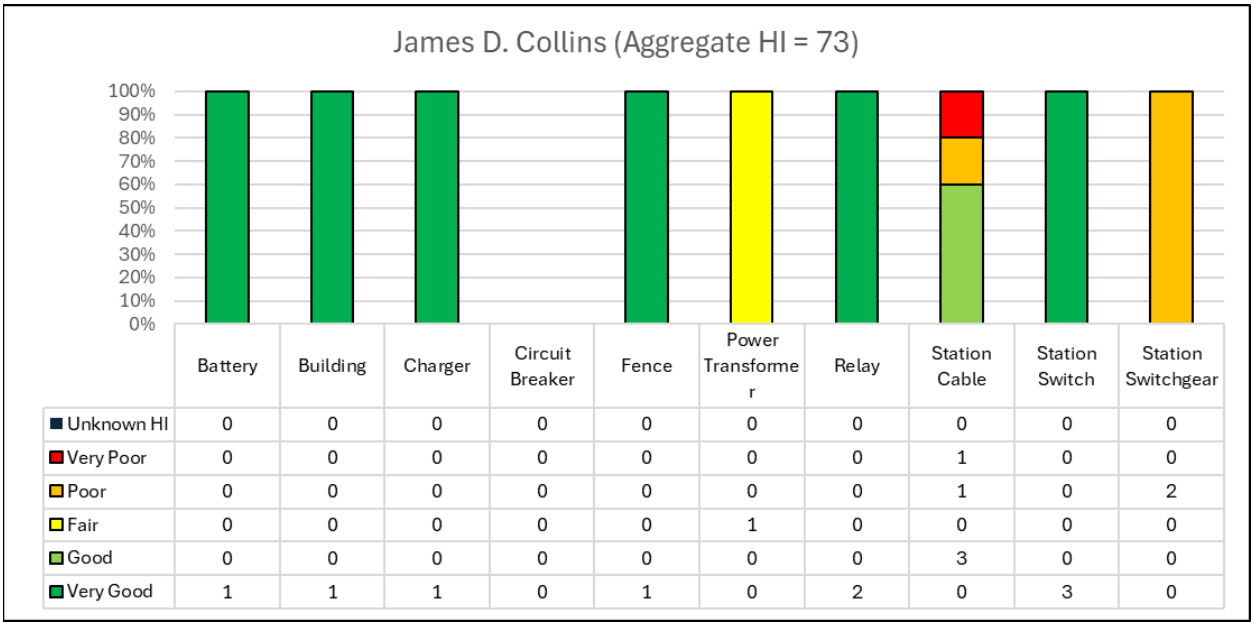
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	1	0	0	1	0	0	0	0
Good	1	0	0	0	0	0	0	0	0	0
Very Good	0	1	0	0	1	0	0	0	4	0

Figure B-30: HI Results at Howard Walker



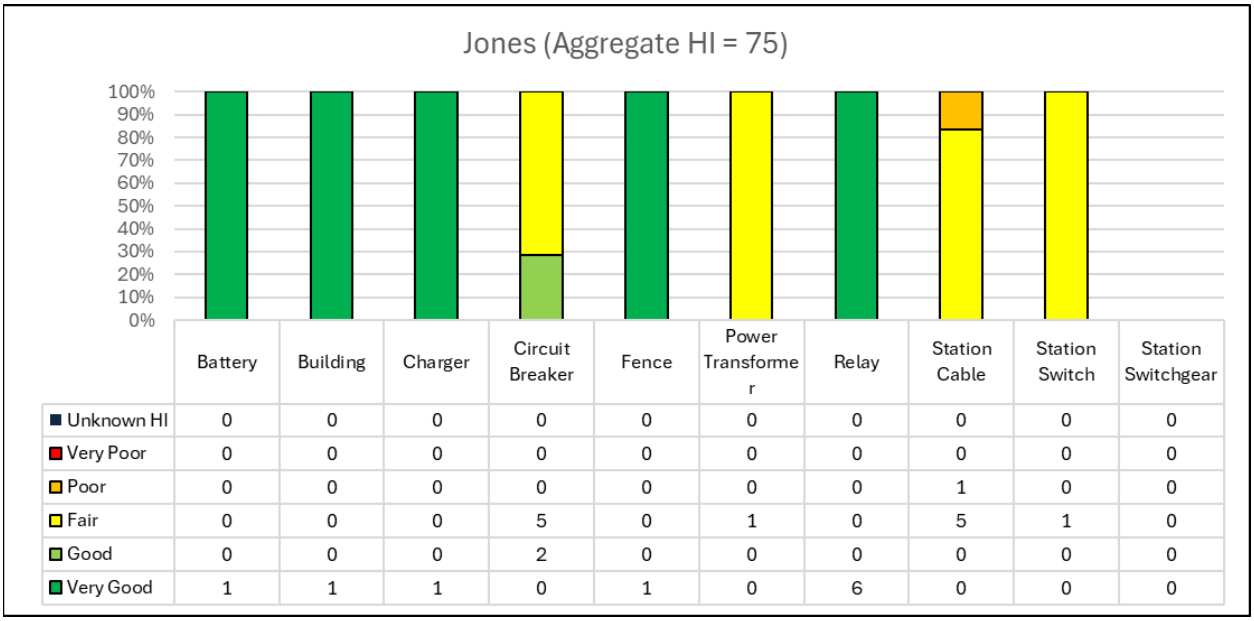
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	0	0	0
Good	1	0	0	0	0	0	0	0	0	0
Very Good	0	0	1	0	1	0	5	0	0	1

Figure B-31: HI Results at James



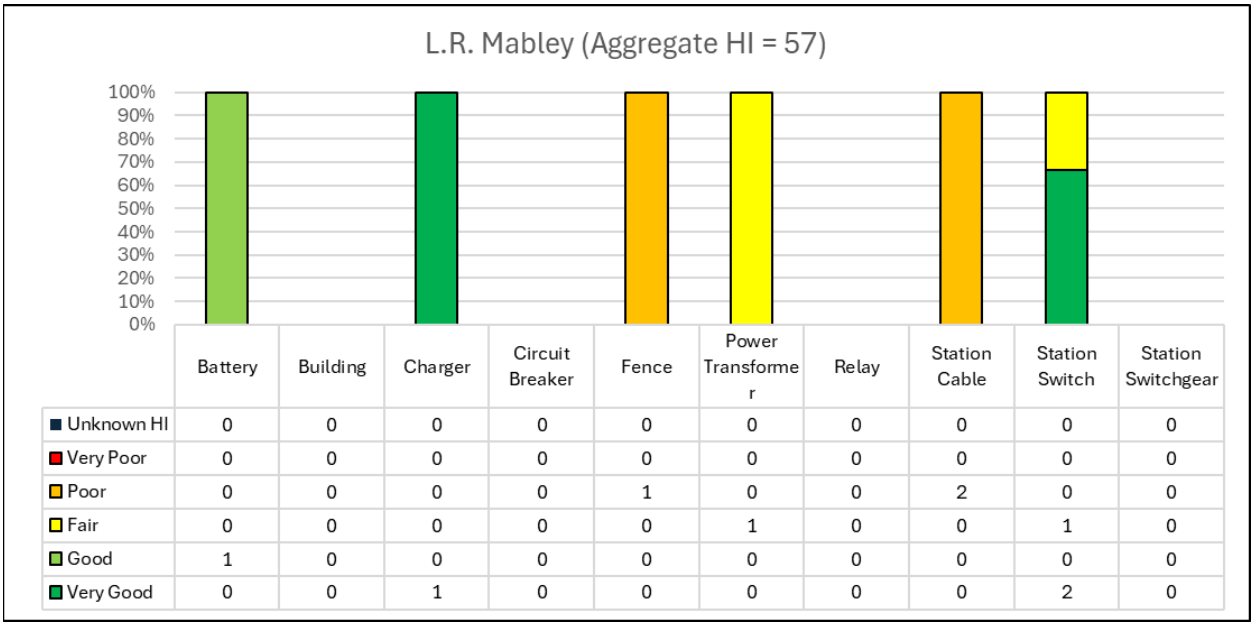
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	2
Fair	0	0	0	0	0	1	0	0	0	0
Good	0	0	0	0	0	0	0	3	0	0
Very Good	1	1	1	0	1	0	2	0	3	0

Figure B-32: HI Results at James D. Collins



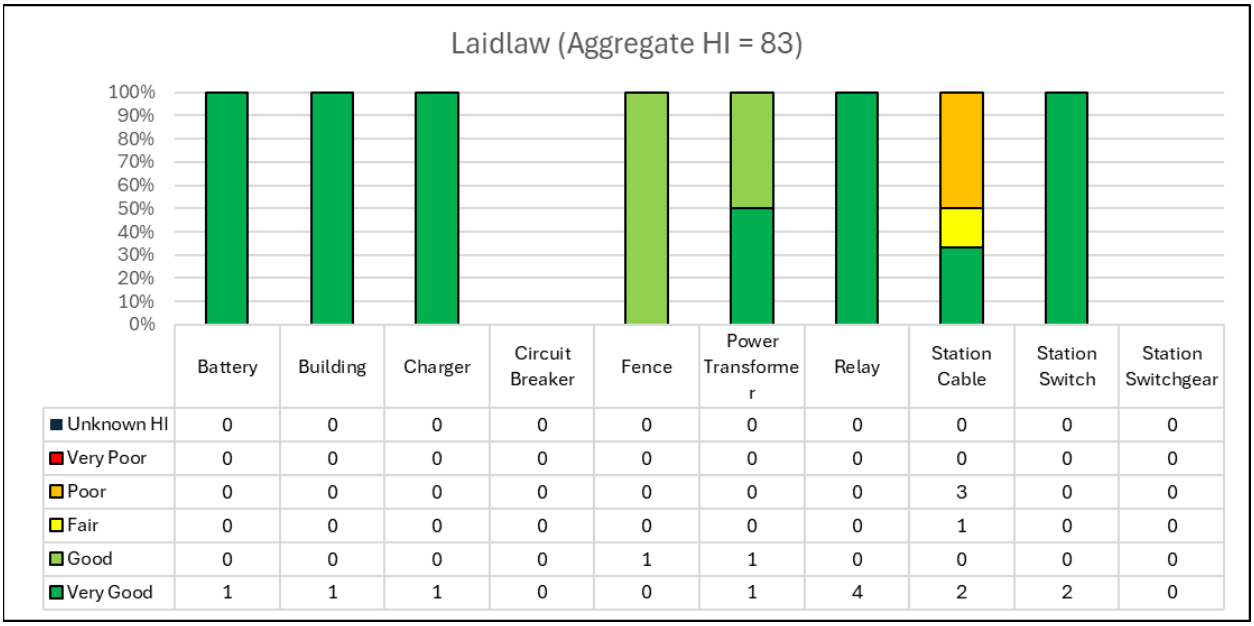
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	5	0	1	0	5	1	0
Good	0	0	0	2	0	0	0	0	0	0
Very Good	1	1	1	0	1	0	6	0	0	0

Figure B-33: HI Results at Jones



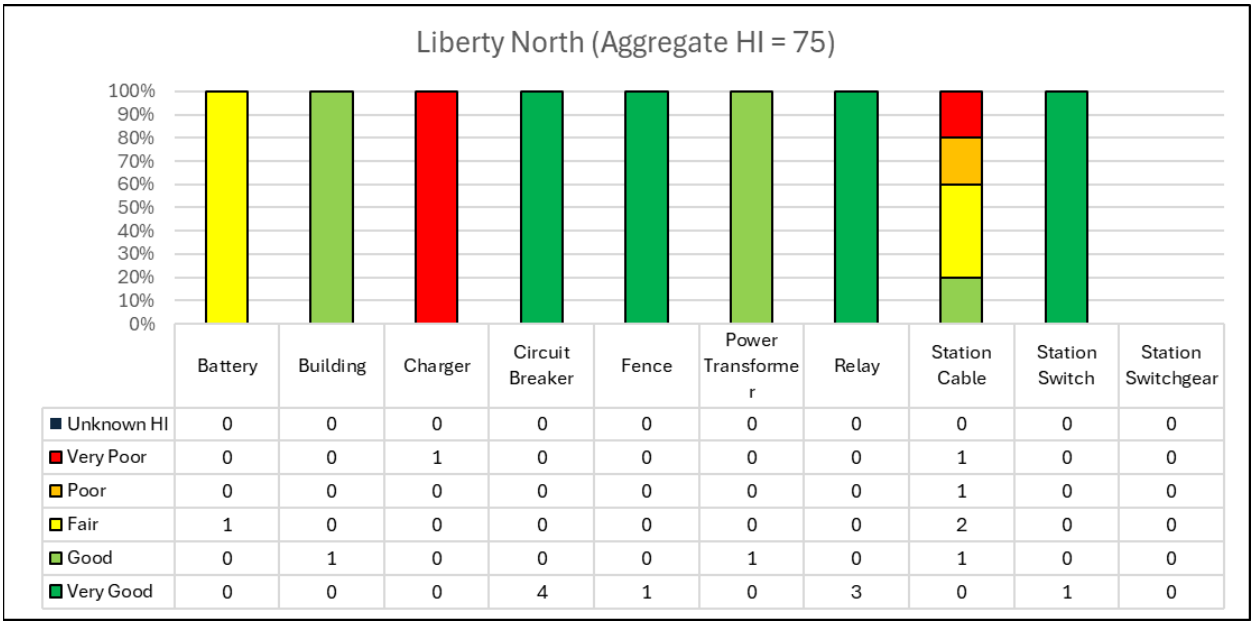
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	1	0	0	2	0	0
Fair	0	0	0	0	0	1	0	0	1	0
Good	1	0	0	0	0	0	0	0	0	0
Very Good	0	0	1	0	0	0	0	0	2	0

Figure B-34: HI Results at L.R. Mabley



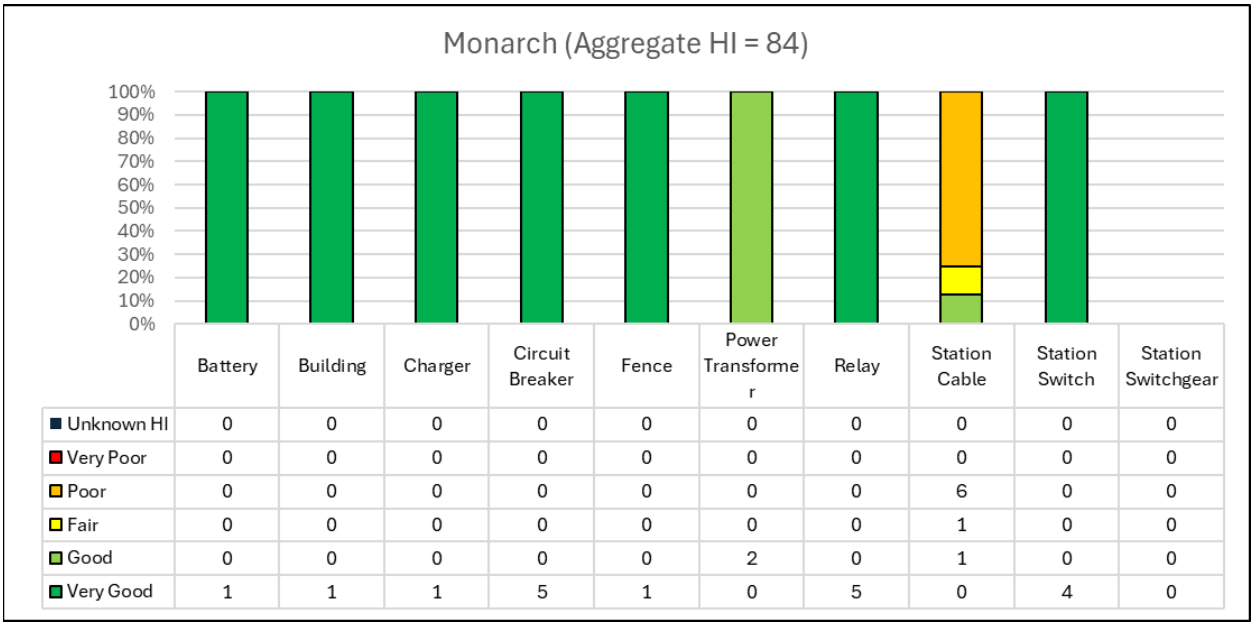
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	3	0	0
Fair	0	0	0	0	0	0	0	1	0	0
Good	0	0	0	0	1	1	0	0	0	0
Very Good	1	1	1	0	0	1	4	2	2	0

Figure B-35: HI Results at Laidlaw



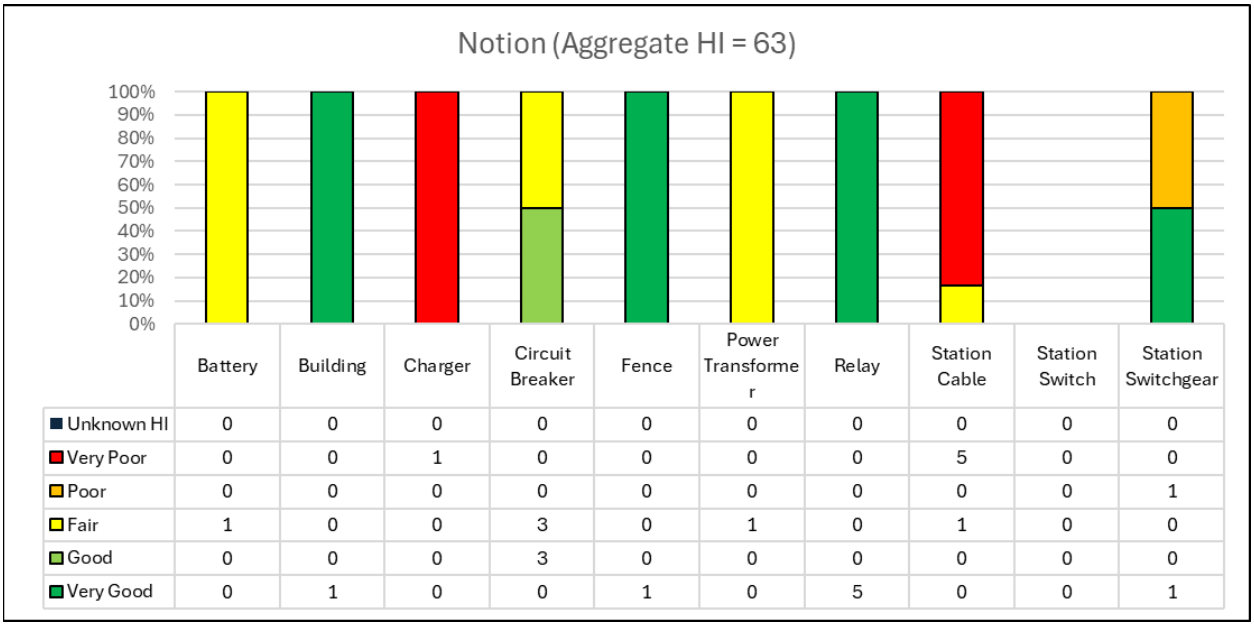
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	1	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	1	0	0	0	0	0	0	2	0	0
Good	0	1	0	0	0	1	0	1	0	0
Very Good	0	0	0	4	1	0	3	0	1	0

Figure B-36: HI Results at Liberty North



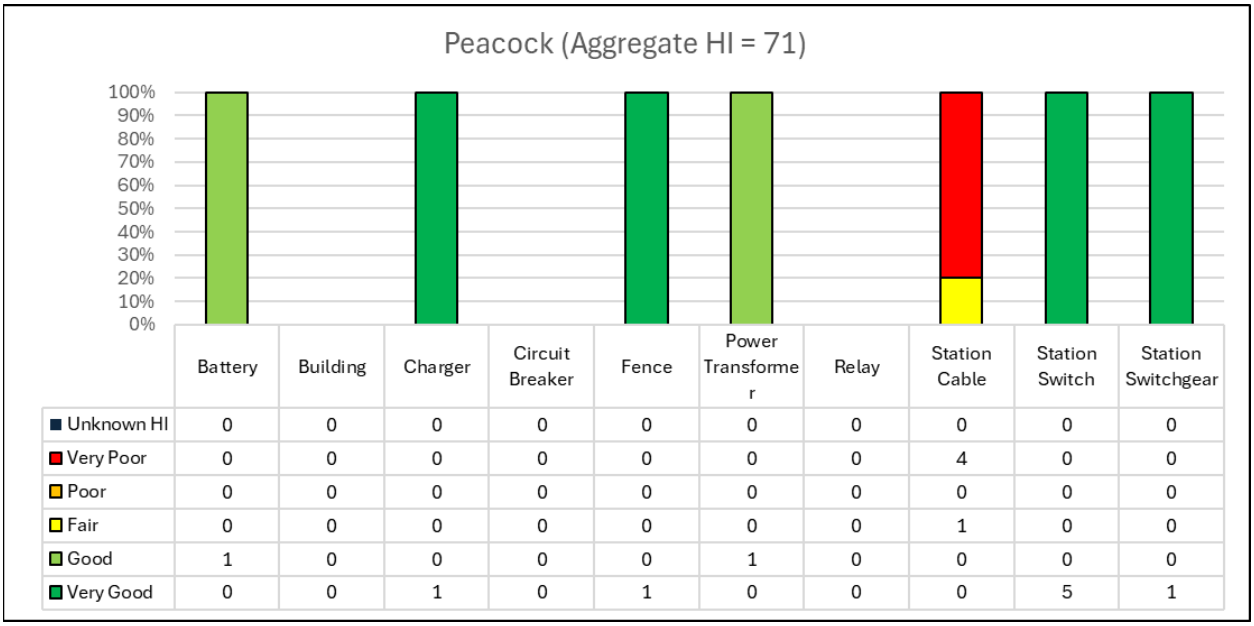
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	6	0	0
Fair	0	0	0	0	0	0	0	1	0	0
Good	0	0	0	0	0	2	0	1	0	0
Very Good	1	1	1	5	1	0	5	0	4	0

Figure B-37: HI Results at Monarch



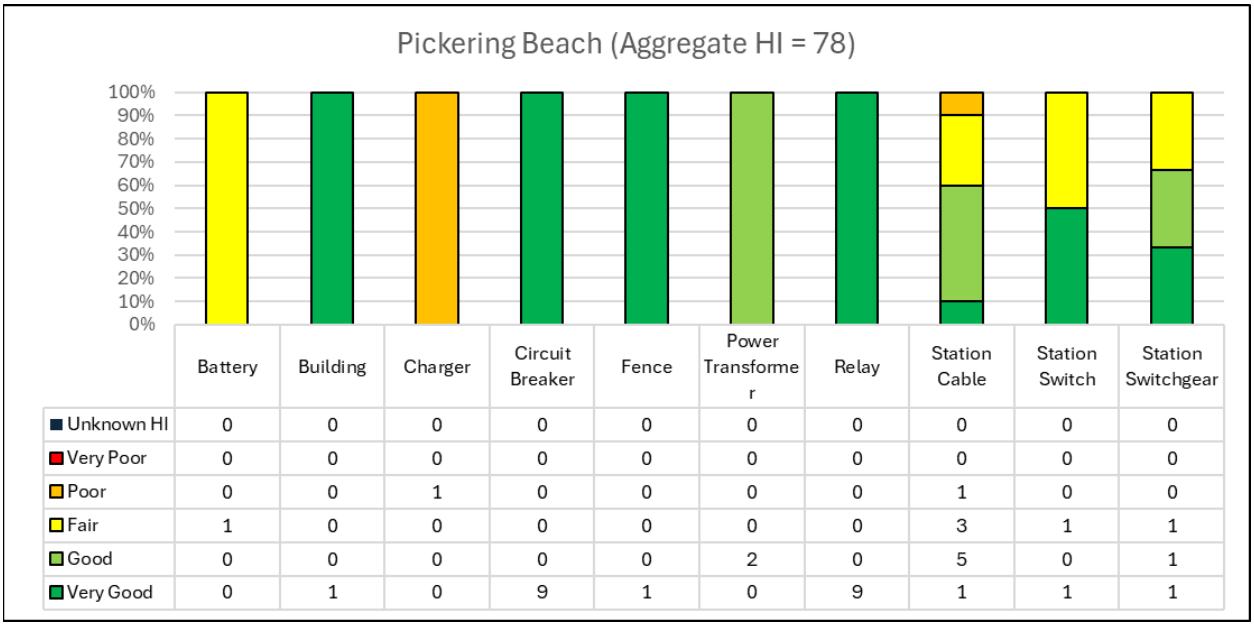
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	1	0	0	0	0	5	0	0
Poor	0	0	0	0	0	0	0	0	0	1
Fair	1	0	0	3	0	1	0	1	0	0
Good	0	0	0	3	0	0	0	0	0	0
Very Good	0	1	0	0	1	0	5	0	0	1

Figure B-38: HI Results at Notion



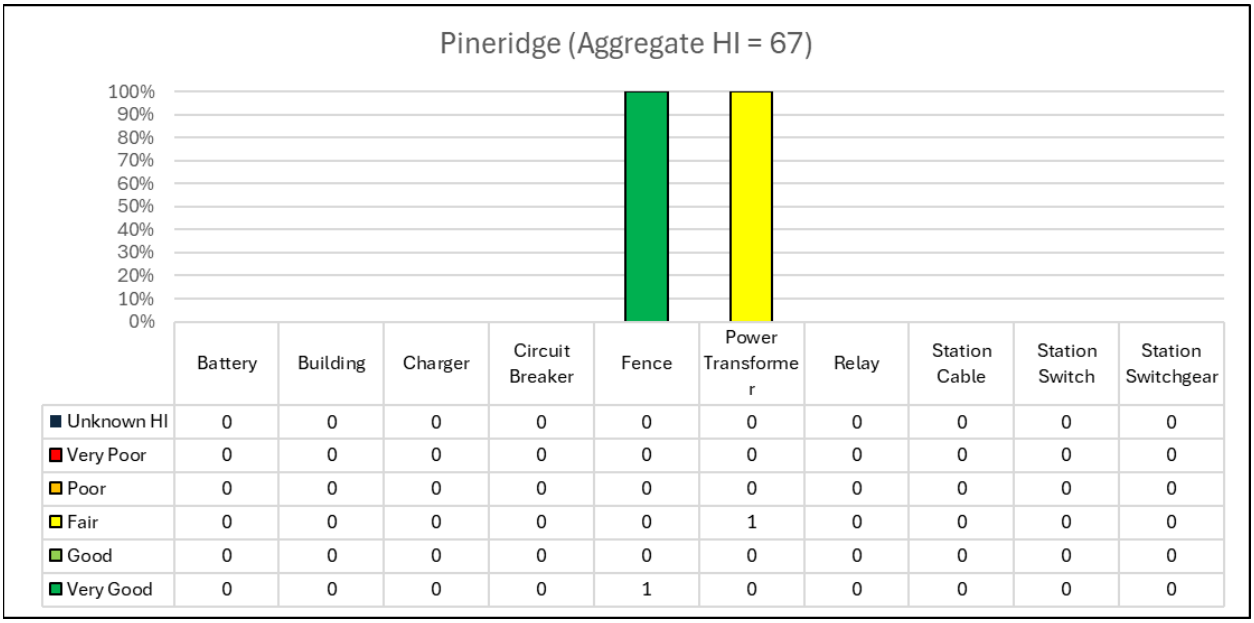
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	4	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	1	0	0
Good	1	0	0	0	0	1	0	0	0	0
Very Good	0	0	1	0	1	0	0	0	5	1

Figure B-39: HI Results at Peacock



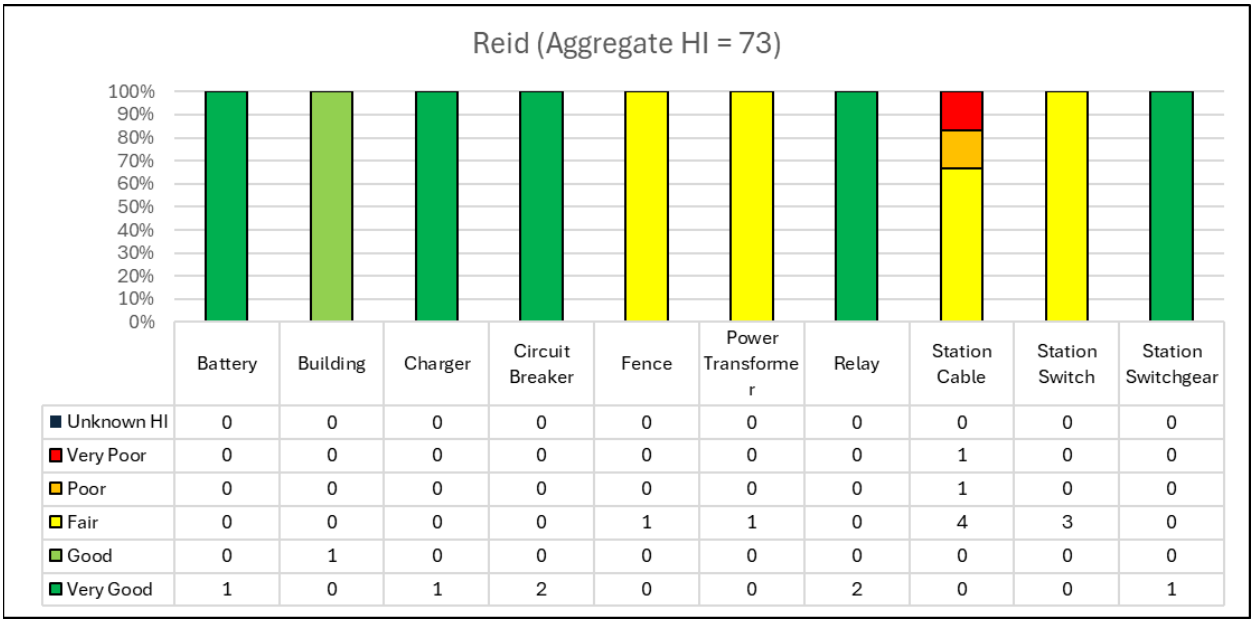
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	1	0	0	0	0	1	0	0
Fair	1	0	0	0	0	0	0	3	1	1
Good	0	0	0	0	0	2	0	5	0	1
Very Good	0	1	0	9	1	0	9	1	1	1

Figure B-40: HI Results at Pickering Beach



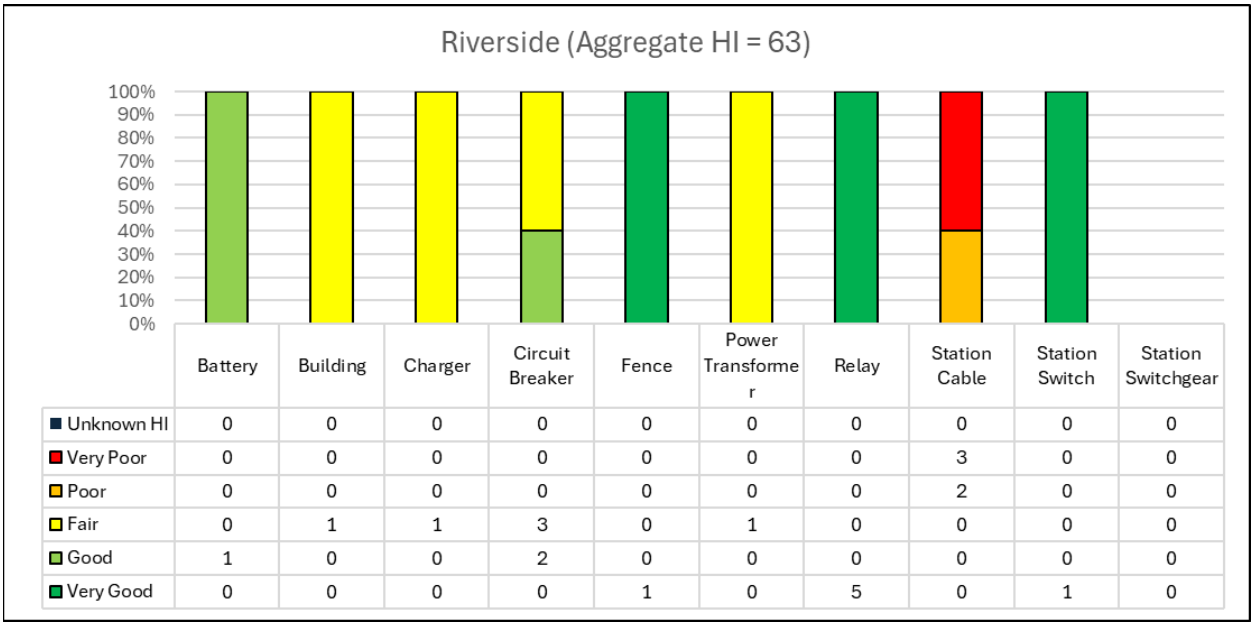
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	0	0	0
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	0	0	0	0

Figure B-41: HI Results at Pineridge



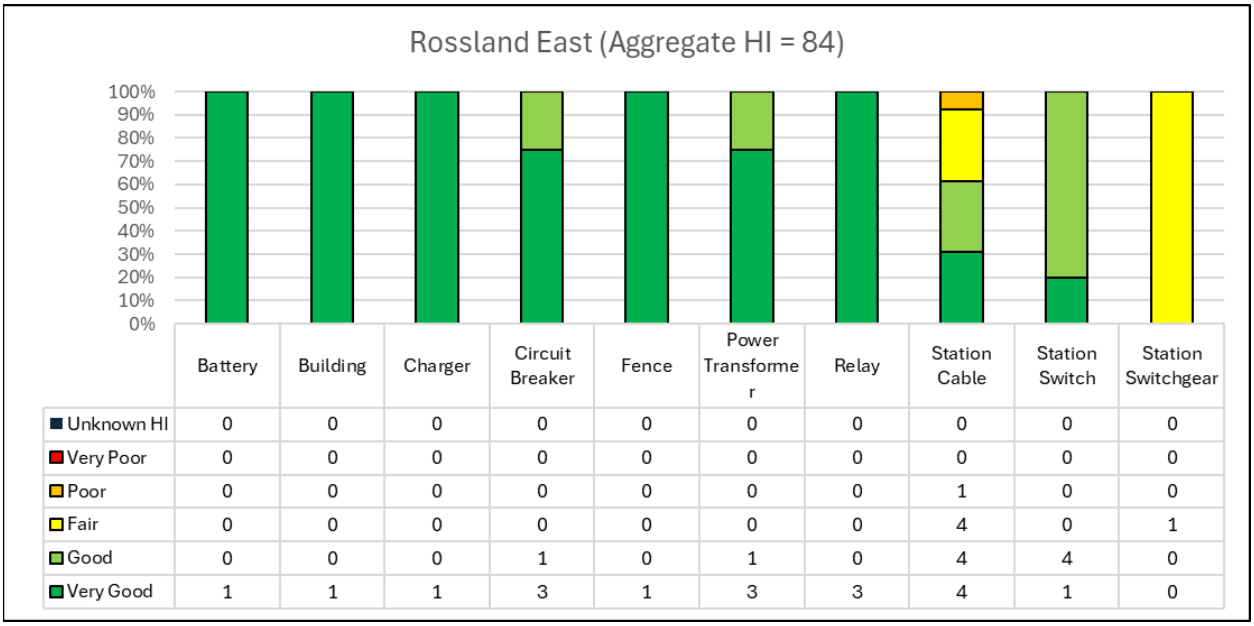
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	1	1	0	4	3	0
Good	0	1	0	0	0	0	0	0	0	0
Very Good	1	0	1	2	0	0	2	0	0	1

Figure B-42: HI Results at Reid



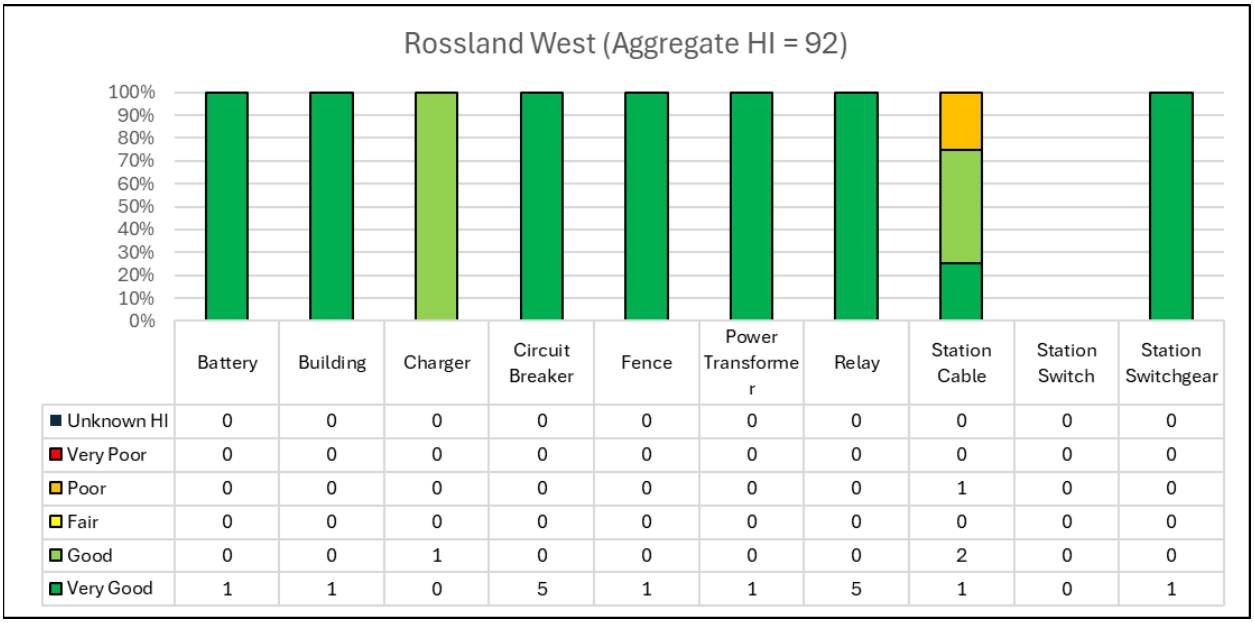
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	3	0	0
Poor	0	0	0	0	0	0	0	2	0	0
Fair	0	1	1	3	0	1	0	0	0	0
Good	1	0	0	2	0	0	0	0	0	0
Very Good	0	0	0	0	1	0	5	0	1	0

Figure B-43: HI Results at Riverside



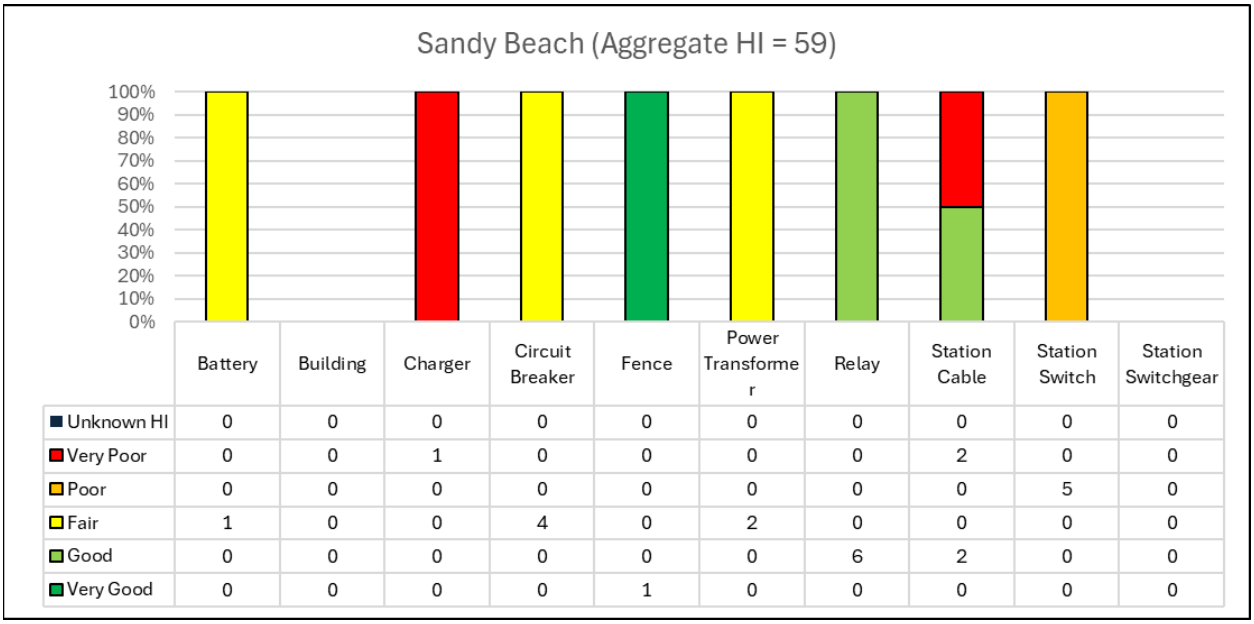
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	0	0	0	4	0	1
Good	0	0	0	1	0	1	0	4	4	0
Very Good	1	1	1	3	1	3	3	4	1	0

Figure B-44: HI Results at Rossland East



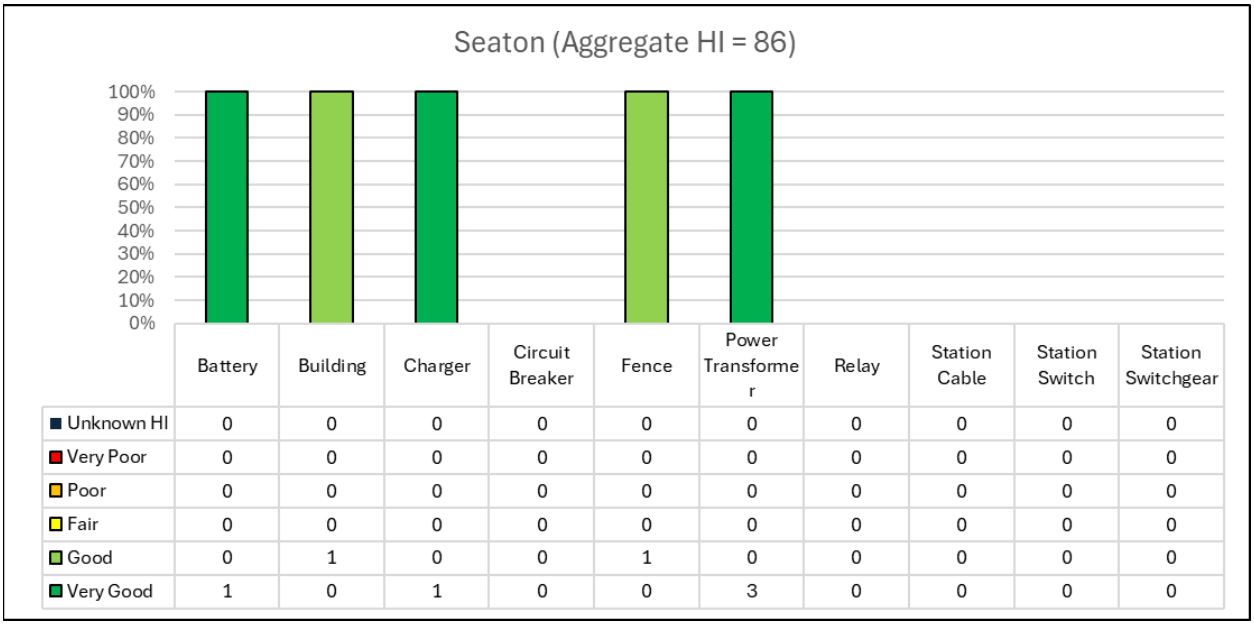
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	0	1	0	0	0	0	2	0	0
Very Good	1	1	0	5	1	1	5	1	0	1

Figure B-45: HI Results at Rossland West



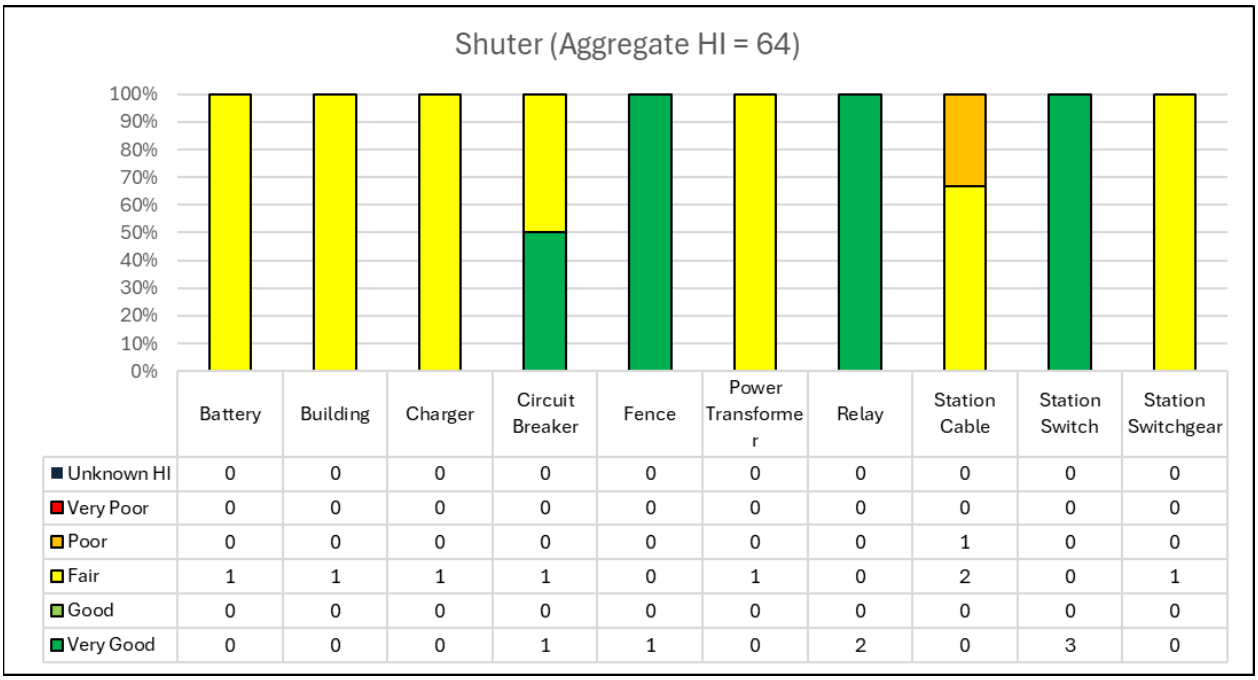
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	1	0	0	0	0	2	0	0
Poor	0	0	0	0	0	0	0	0	5	0
Fair	1	0	0	4	0	2	0	0	0	0
Good	0	0	0	0	0	0	6	2	0	0
Very Good	0	0	0	0	1	0	0	0	0	0

Figure B-46: HI Results at Sandy Beach



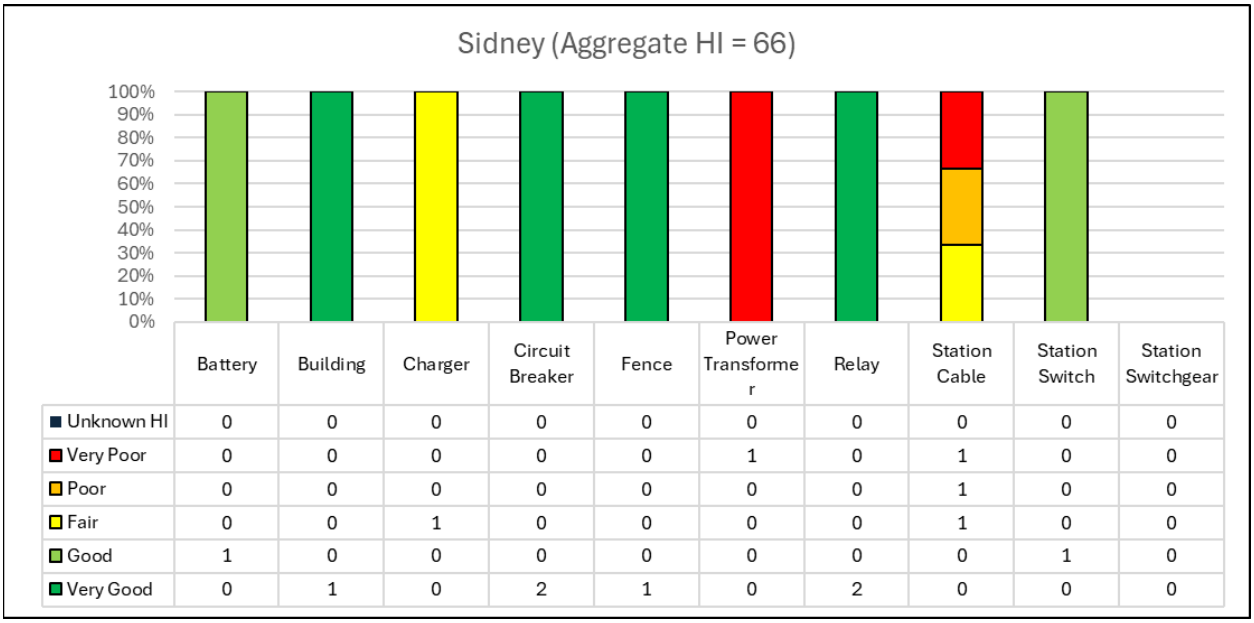
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	0	0	0
Good	0	1	0	0	1	0	0	0	0	0
Very Good	1	0	1	0	0	3	0	0	0	0

Figure B-47: HI Results at Seaton



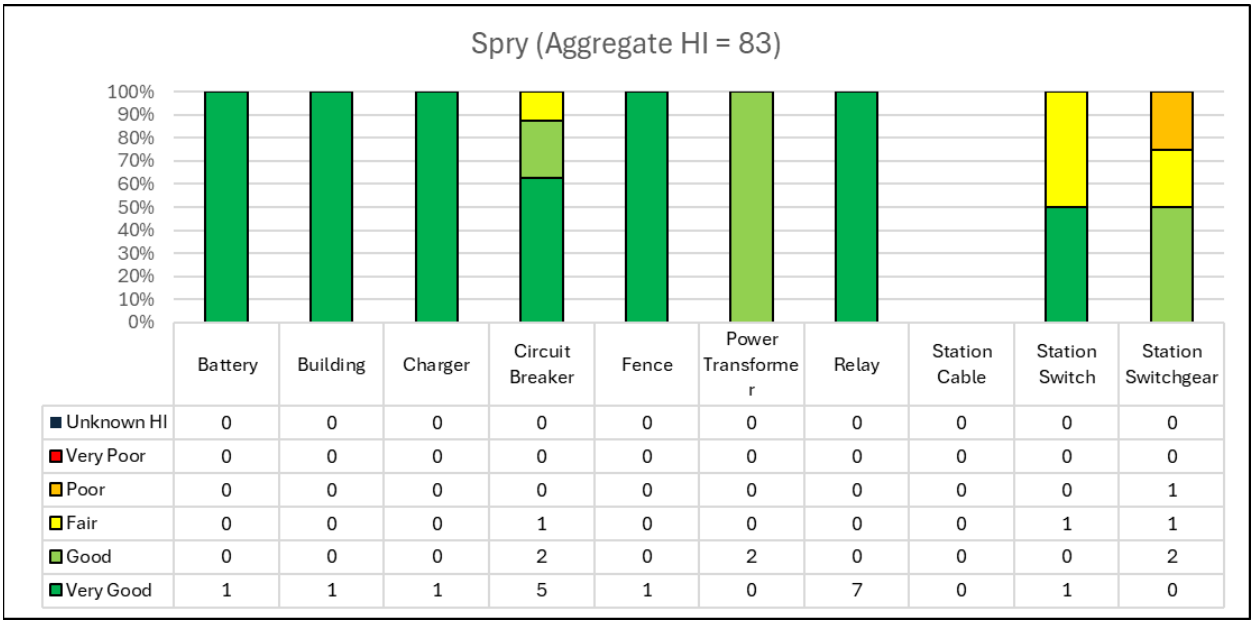
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	1	1	1	1	0	1	0	2	0	1
Good	0	0	0	0	0	0	0	0	0	0
Very Good	0	0	0	1	1	0	2	0	3	0

Figure B-48: HI Results at Shuter



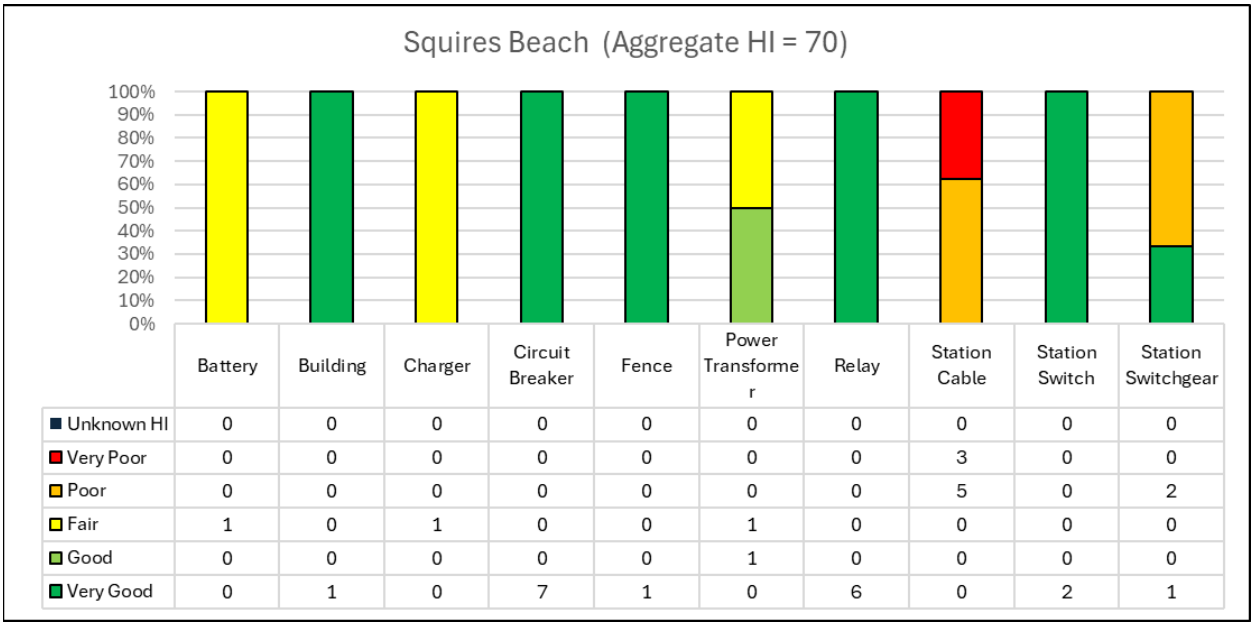
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	1	0	1	0	0
Poor	0	0	0	0	0	0	0	1	0	0
Fair	0	0	1	0	0	0	0	1	0	0
Good	1	0	0	0	0	0	0	0	1	0
Very Good	0	1	0	2	1	0	2	0	0	0

Figure B-49: HI Results at Sidney



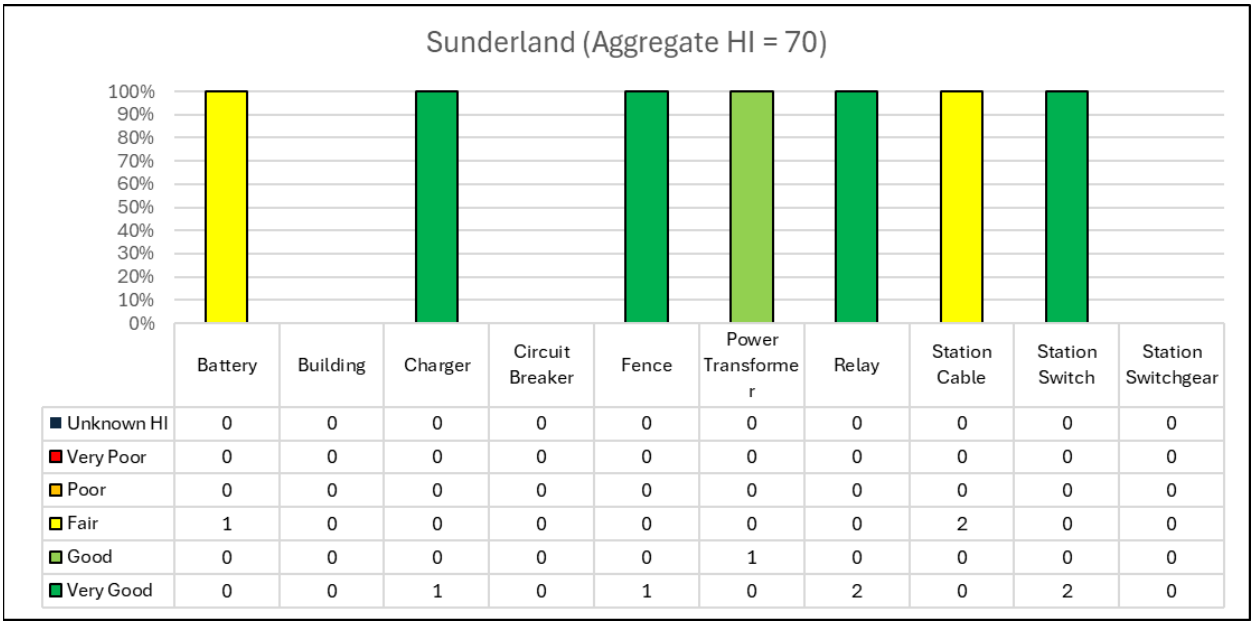
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	1
Fair	0	0	0	1	0	0	0	0	1	1
Good	0	0	0	2	0	2	0	0	0	2
Very Good	1	1	1	5	1	0	7	0	1	0

Figure B-50: HI Results at Spry



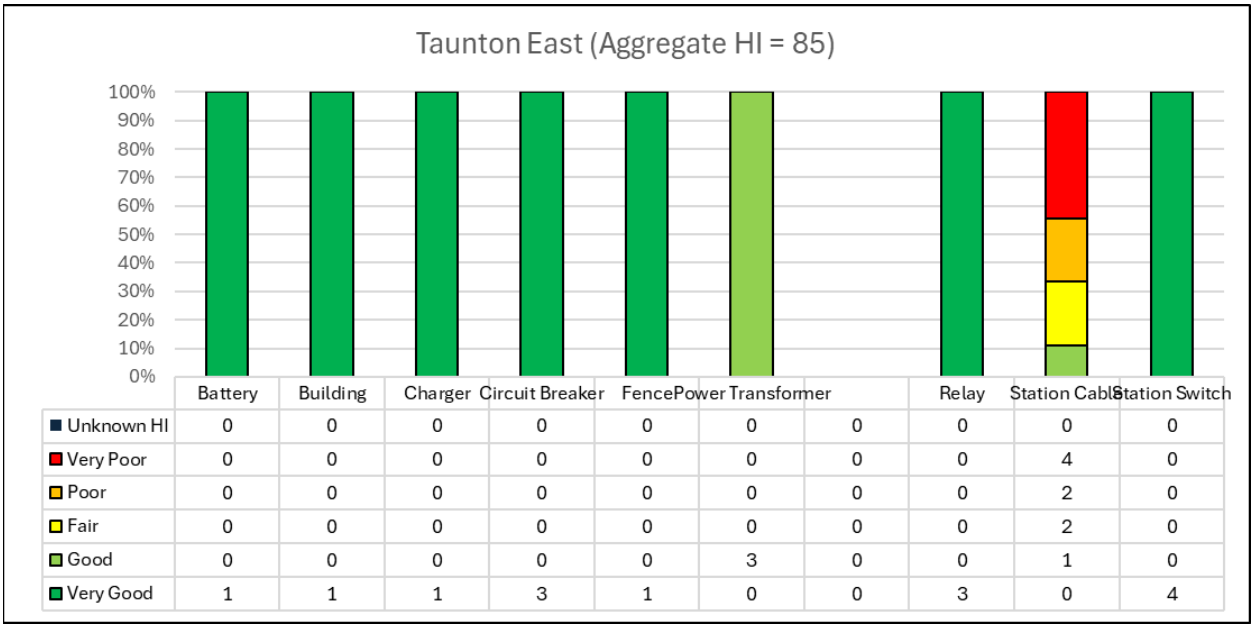
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	3	0	0
Poor	0	0	0	0	0	0	0	5	0	2
Fair	1	0	1	0	0	1	0	0	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	0	1	0	7	1	0	6	0	2	1

Figure B-51: HI Results at Squires Beach



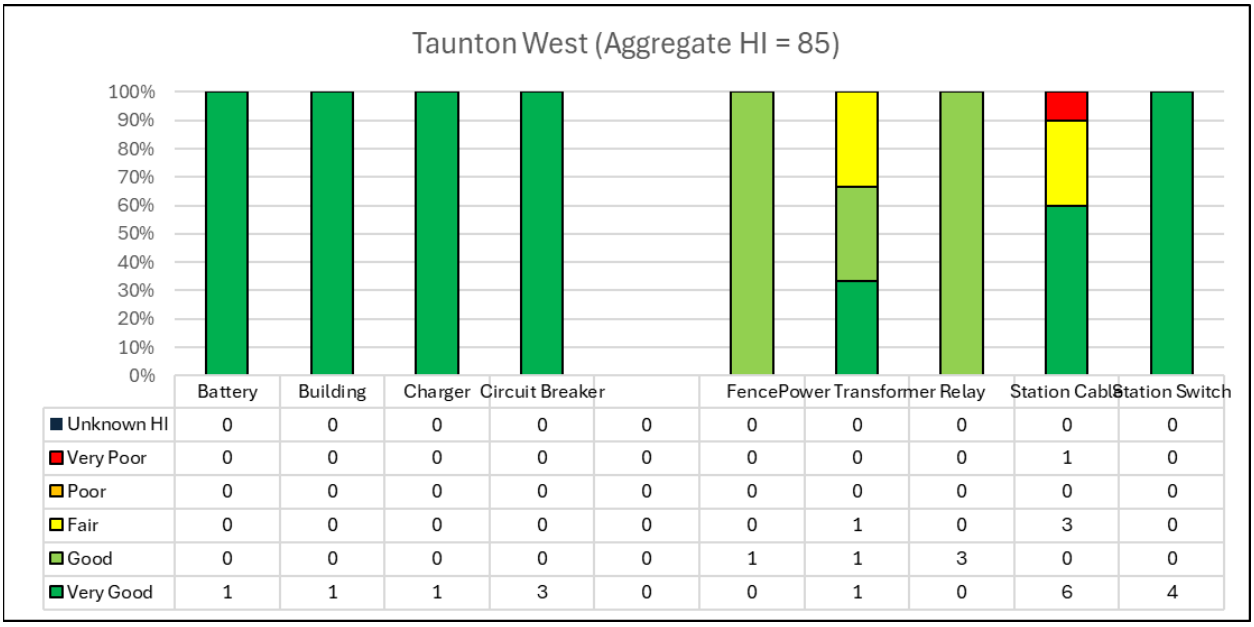
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	1	0	0	0	0	0	0	2	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	0	0	1	0	1	0	2	0	2	0

Figure B-52: HI Results at Sunderland



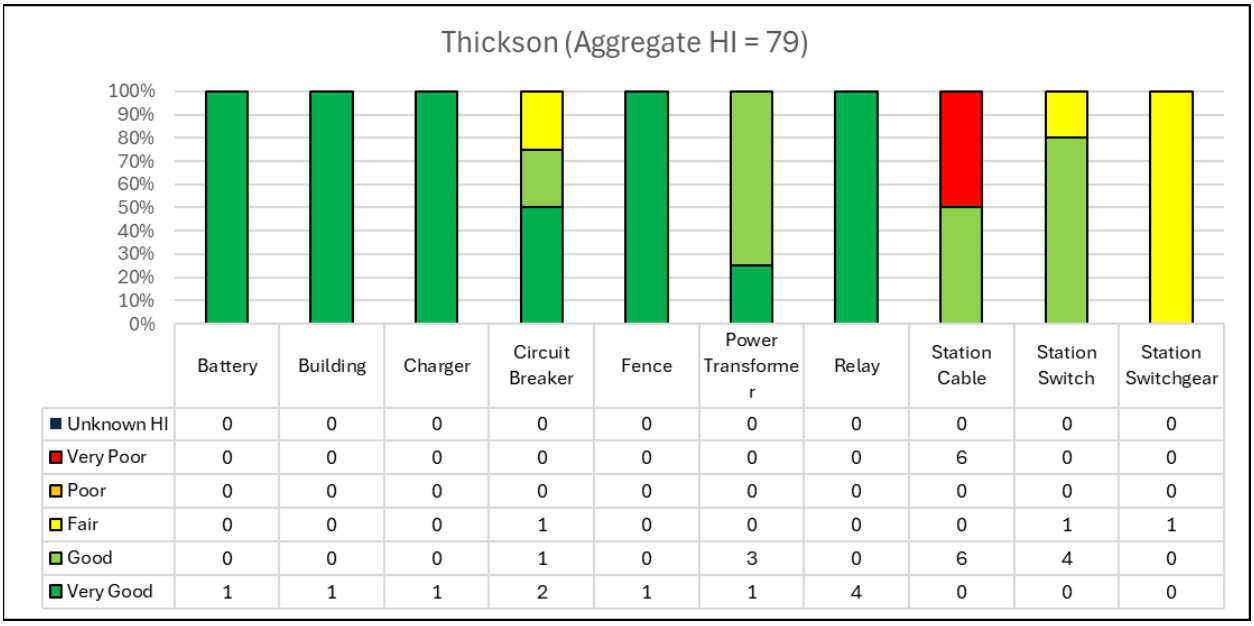
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer		Relay	Station Cabl	Station Switch
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	4	0
Poor	0	0	0	0	0	0	0	0	2	0
Fair	0	0	0	0	0	0	0	0	2	0
Good	0	0	0	0	0	3	0	0	1	0
Very Good	1	1	1	3	1	0	0	3	0	4

Figure B-53: HI Results at Taunton East



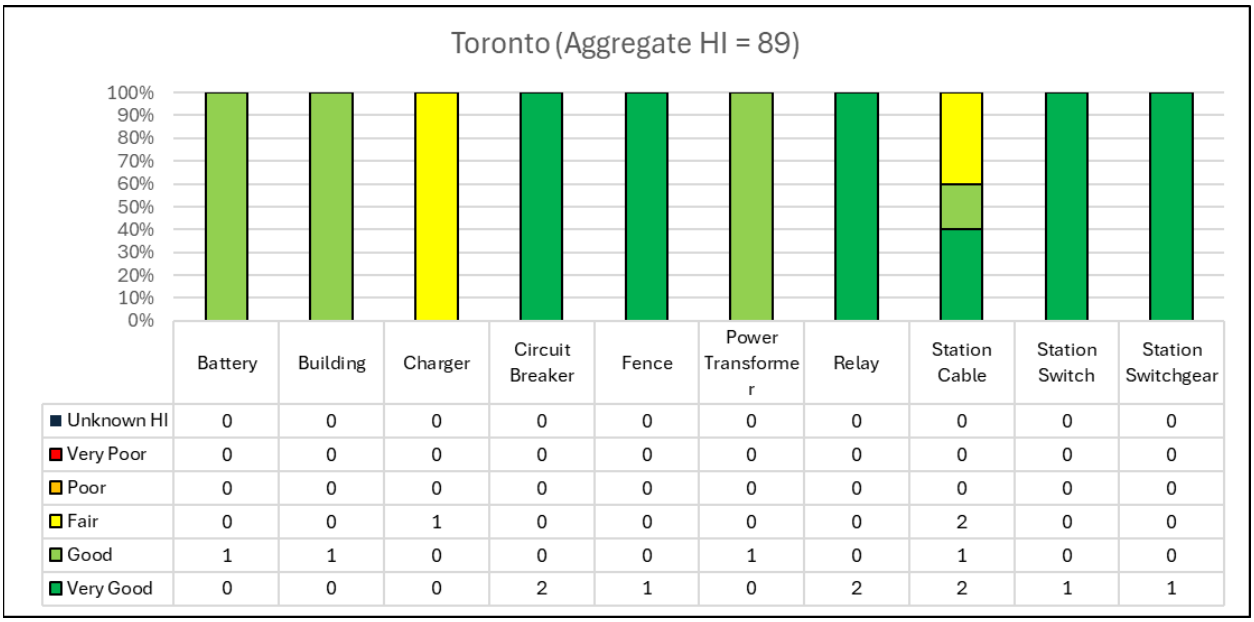
	Battery	Building	Charger	Circuit Breaker		Fence	Power Transformer	Relay	Station Cabl	Station Switch
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	1	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	1	0	3	0
Good	0	0	0	0	0	1	1	3	0	0
Very Good	1	1	1	3	0	0	1	0	6	4

Figure B-54: HI Results at Taunton West



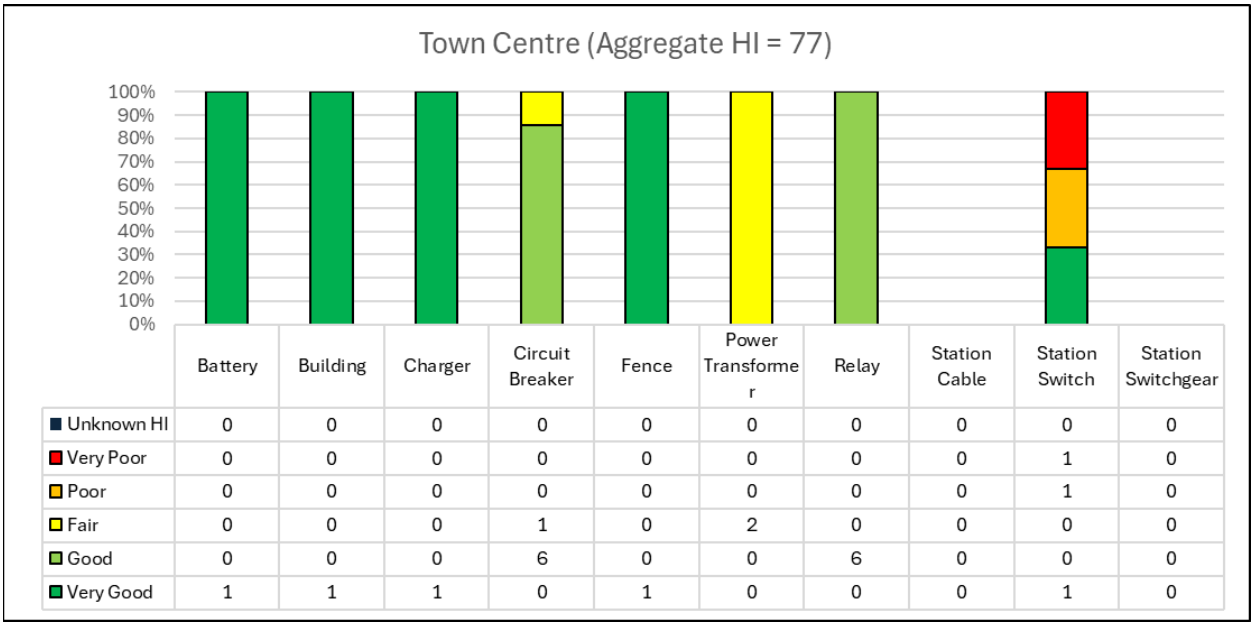
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	6	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	1	0	0	0	0	1	1
Good	0	0	0	1	0	3	0	6	4	0
Very Good	1	1	1	2	1	1	4	0	0	0

Figure B-55: HI Results at Thickson



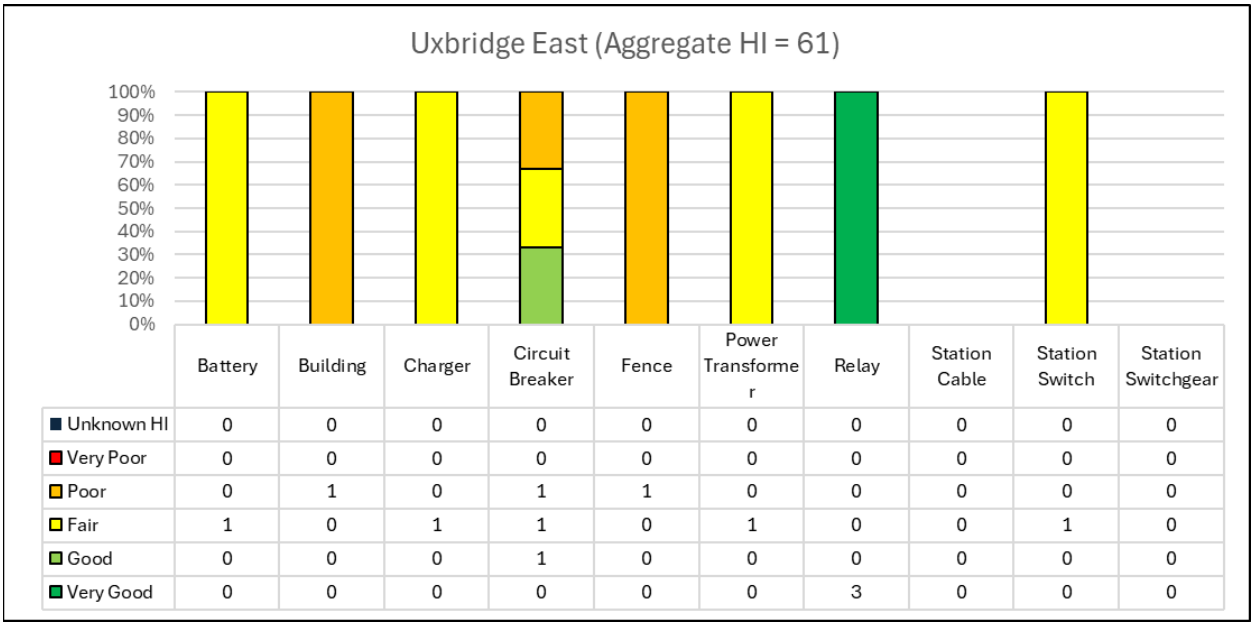
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	1	0	0	0	0	2	0	0
Good	1	1	0	0	0	1	0	1	0	0
Very Good	0	0	0	2	1	0	2	2	1	1

Figure B-56: HI Results at Toronto



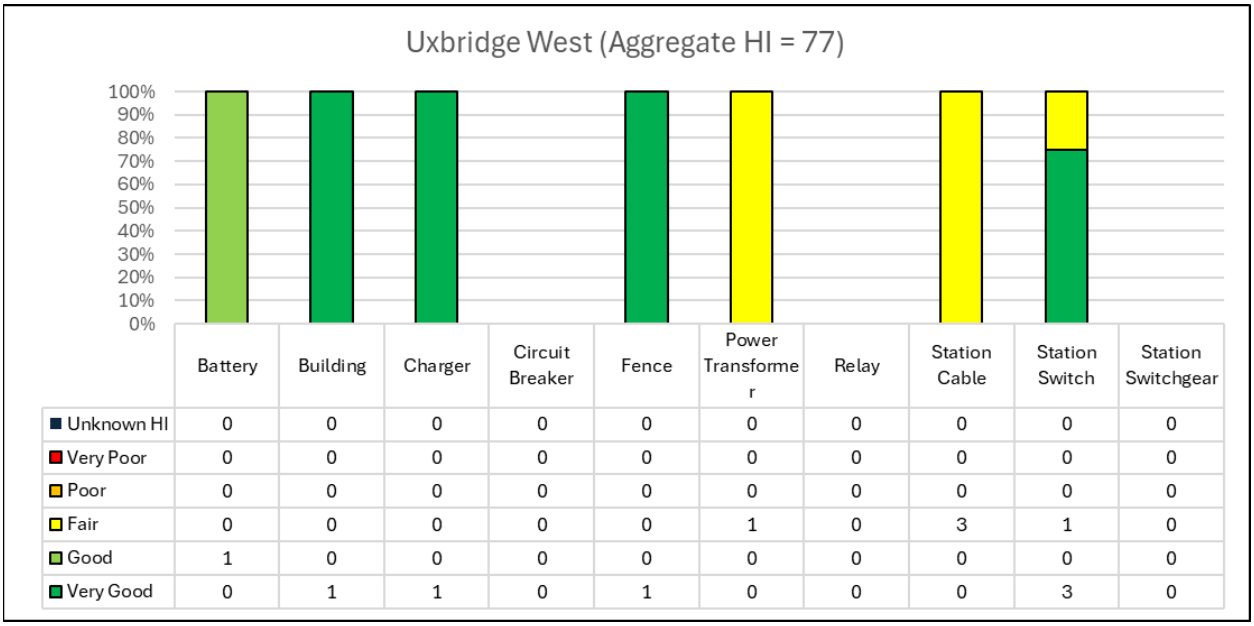
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	1	0
Poor	0	0	0	0	0	0	0	0	1	0
Fair	0	0	0	1	0	2	0	0	0	0
Good	0	0	0	6	0	0	6	0	0	0
Very Good	1	1	1	0	1	0	0	0	1	0

Figure B-57: HI Results at Town Centre



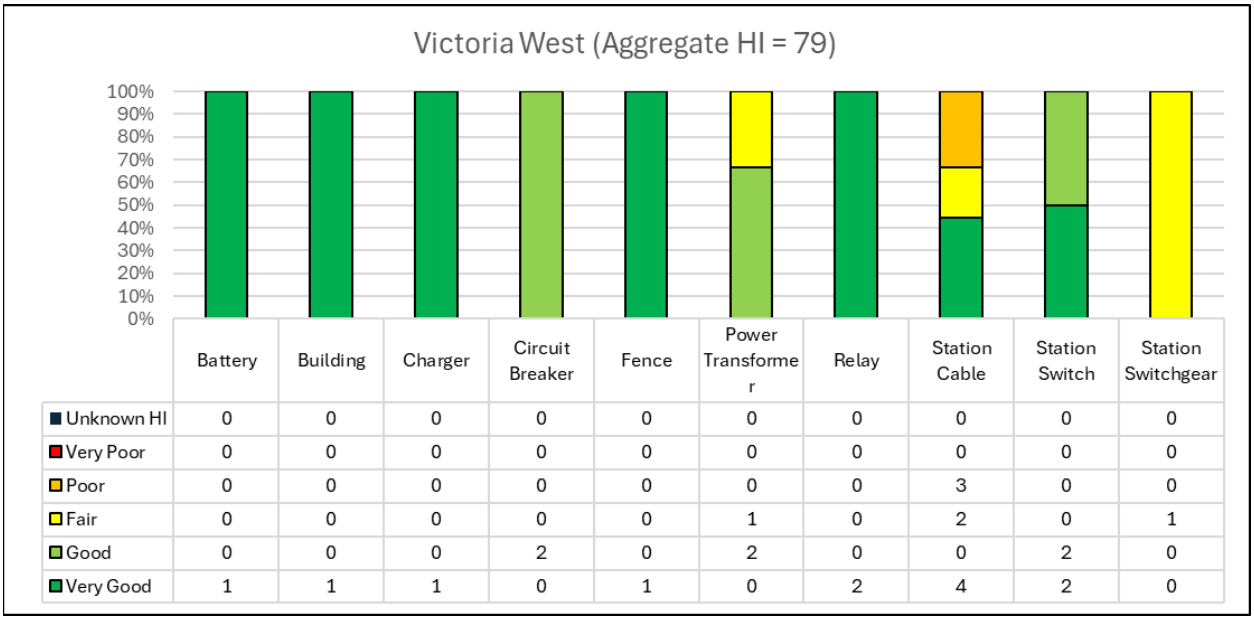
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	1	0	1	1	0	0	0	0	0
Fair	1	0	1	1	0	1	0	0	1	0
Good	0	0	0	1	0	0	0	0	0	0
Very Good	0	0	0	0	0	0	3	0	0	0

Figure B-58: HI Results at Uxbridge East



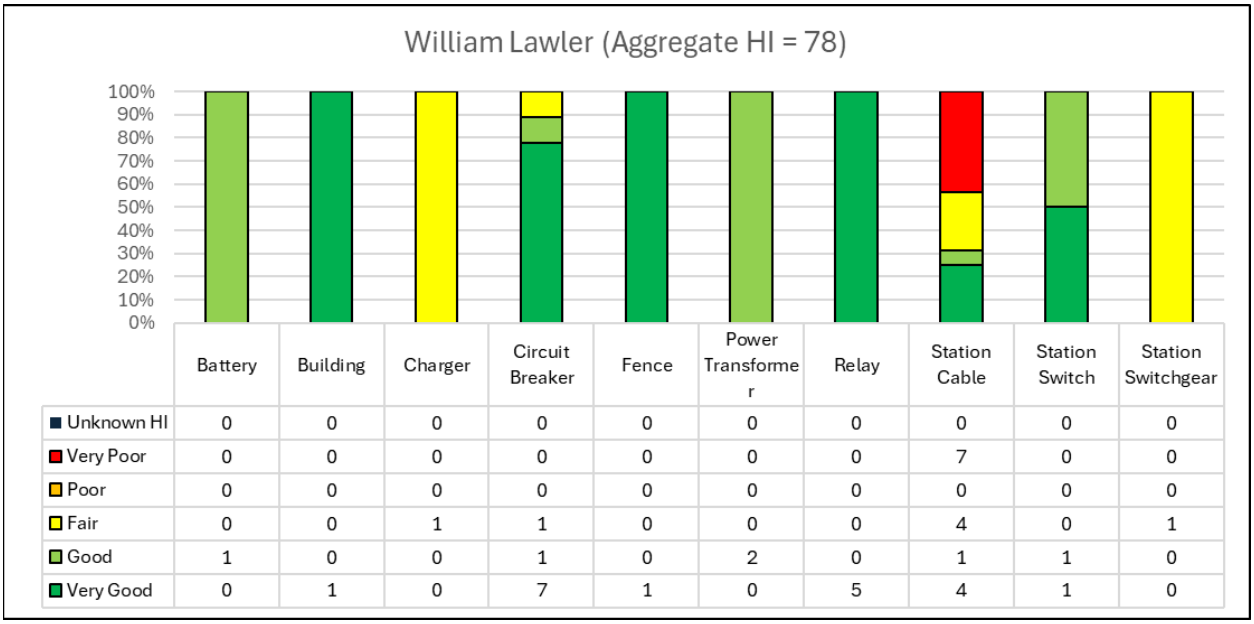
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	1	0	3	1	0
Good	1	0	0	0	0	0	0	0	0	0
Very Good	0	1	1	0	1	0	0	0	3	0

Figure B-59: HI Results at Uxbridge West



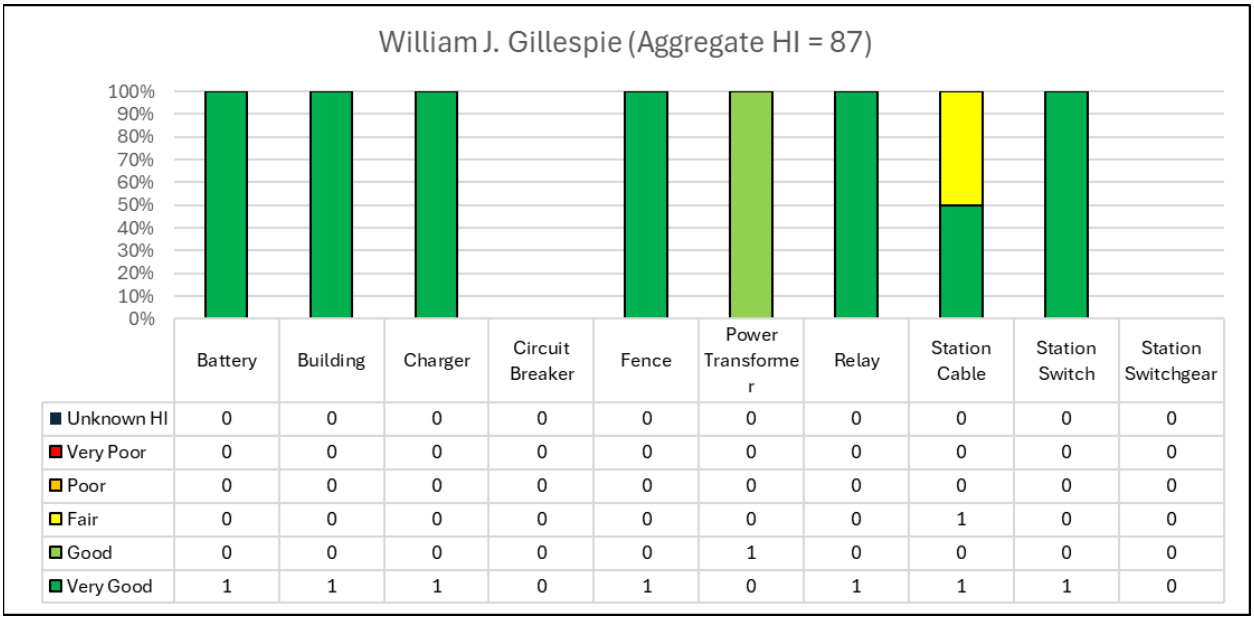
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	3	0	0
Fair	0	0	0	0	0	1	0	2	0	1
Good	0	0	0	2	0	2	0	0	2	0
Very Good	1	1	1	0	1	0	2	4	2	0

Figure B-60: HI Results at Victoria West



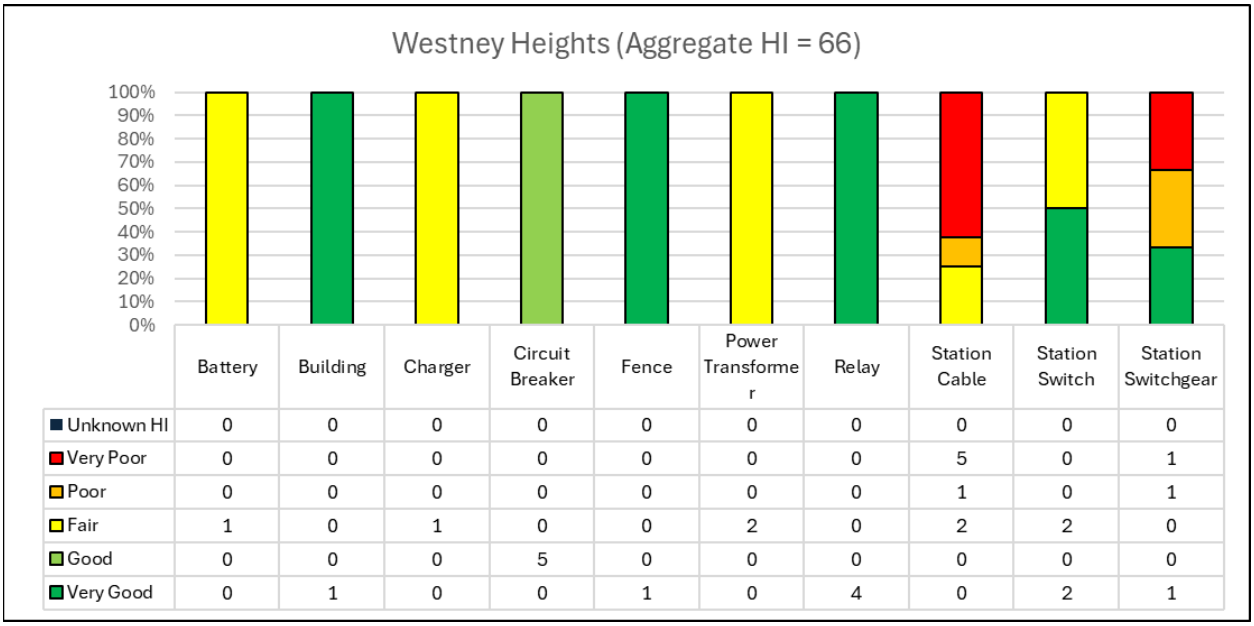
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	7	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	1	1	0	0	0	4	0	1
Good	1	0	0	1	0	2	0	1	1	0
Very Good	0	1	0	7	1	0	5	4	1	0

Figure B-61: HI Results at William Lawler



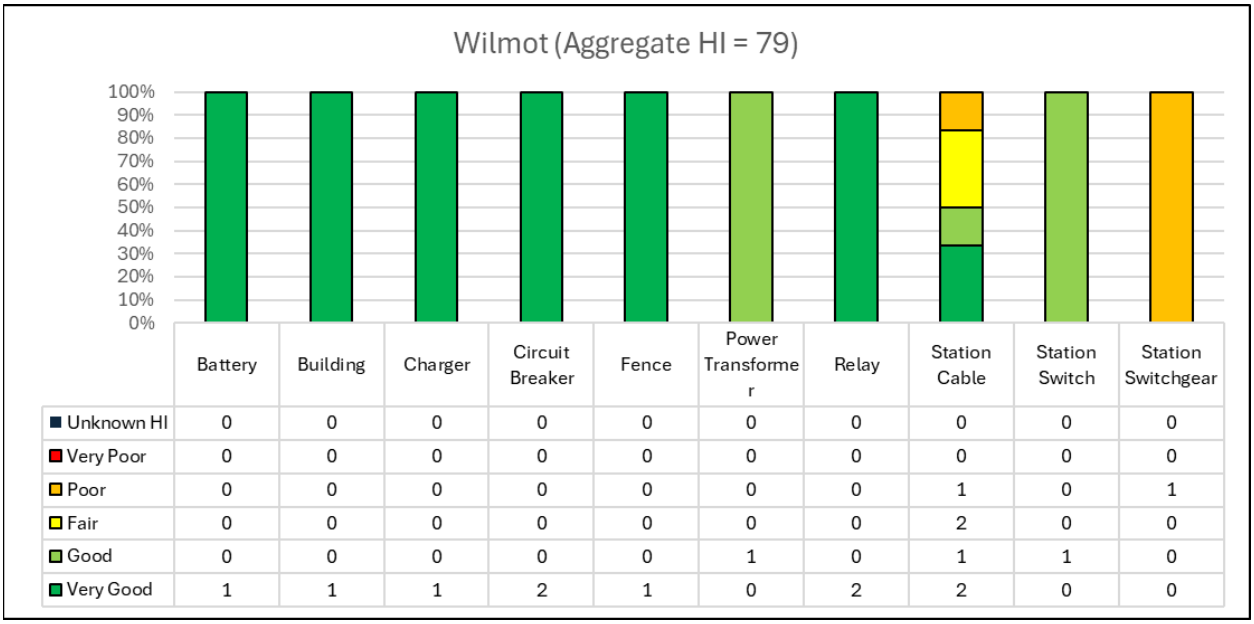
	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	0	0	0
Fair	0	0	0	0	0	0	0	1	0	0
Good	0	0	0	0	0	1	0	0	0	0
Very Good	1	1	1	0	1	0	1	1	1	0

Figure B-62: HI Results at William J. Gillespie



	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	5	0	1
Poor	0	0	0	0	0	0	0	1	0	1
Fair	1	0	1	0	0	2	0	2	2	0
Good	0	0	0	5	0	0	0	0	0	0
Very Good	0	1	0	0	1	0	4	0	2	1

Figure B-63: HI Results at Westney Heights



	Battery	Building	Charger	Circuit Breaker	Fence	Power Transformer	Relay	Station Cable	Station Switch	Station Switchgear
Unknown HI	0	0	0	0	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0	1	0	1
Fair	0	0	0	0	0	0	0	2	0	0
Good	0	0	0	0	0	1	0	1	1	0
Very Good	1	1	1	2	1	0	2	2	0	0

Figure B-64: HI Results at Wilmot

ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

This section presents Elexicon's asset lifecycle optimization and risk management procedures and practices. Elexicon owns and operates assets within its service territory and is responsible for the management of all its distribution and substation assets. Elexicon maintains the efficiency and reliability of its system through active inspection, maintenance, and Asset Management (AM) processes. The objective of Elexicon's asset lifecycle optimization policy is to provide the optimal level of service to customers by ensuring the electrical system operates as designed, constructed, and maintained to ensure its reliability, resiliency, safety, and affordability. The specific description of procedures and practices in the following sub-sections describe the policies and practices Elexicon employs to those asset lifecycle objectives.

The asset lifecycle practices and procedures employed by Elexicon are asset-specific and range from visual inspections to more in-depth examinations, such as testing and analysis. The information gathered from these practices is used to determine a course of action with respect to the asset and primarily informs the System Renewal portion of Elexicon's capital plan.

1. ASSET REPLACEMENT AND REFURBISHMENT POLICY

Elexicon's maintenance and inspection programs occasionally identify equipment that is beyond economical repair or no longer compliant with operational requirements. In these cases, the utility undertakes asset replacement or refurbishment under its capital investment program.

Replacement decisions consider:

- Asset condition and asset age relative to TUL;
- Risk and consequence of failure (safety, reliability, environment);
- Obsolescence and availability of spare parts;
- Compliance with applicable standards and regulations;
- Cost-benefit analysis of refurbishment vs. replacement.

Asset Intervention Practices

In-service equipment identified as requiring intervention, due to condition assessments, repeated failures, or manufacturer recalls, is systematically addressed through either a maintenance and repair program (refurbishment) or a planned capital investment program (replacement). This process involves identifying the locations of the assets to be intervened upon and performing GIS tracking and monitoring. An intervention may include replacement or rehabilitation, depending on the asset class type.

Elexicon's asset replacement strategies regarding its different asset classes are summarized in Table 1 below.

Asset replacement is typically pursued when maintenance or refurbishment is no longer technically or economically viable. This may occur when an asset's condition deteriorates to the point where failure risk or safety concerns outweigh the cost of replacement, or when the asset becomes non-maintainable due to obsolete components, discontinued manufacturer support, or outdated design standards. Replacement is also prioritized for assets that pose operational safety hazards, have repeated failure histories, or are incompatible with modern system configurations and reliability requirements. In such cases, Elexicon evaluates the cost of continued maintenance versus replacement to ensure prudent investment decisions that maintain system reliability and safety.

Table 1: Summary of Elexicon's Asset Intervention Practices

Asset Class	Primary Intervention Strategy	Description
Poles	Proactive and Reactive Replacement	Wood poles are replaced when they fail or when testing indicates poor or very poor condition, loss of structural integrity, or compromised load-bearing capacity. Replacement prioritization considers asset health index, safety risk, and criticality of attached equipment.

Asset Class	Primary Intervention Strategy	Description
Overhead Distribution Conductors	Reactive Replacement or Proactive Replacement with Other Investments	Overhead conductors are generally replaced only when damaged by faults, weather events, or third-party contact. Proactive replacement may occur as part of area rebuilds or in cases of persistent reliability issues. Area rebuilds are initiated in regions where aging, deteriorated, or obsolete distribution infrastructure presents elevated reliability risks and extended outage restoration times.
Overhead Switches	Proactive Replacement based upon Testing and Inspection Results, or Reactive Replacement	Overhead switches showing excessive heating in IR scans or in poor or very poor condition are proactively replaced; all others are replaced reactively upon failure or in conjunction with other system upgrades.
Padmount Transformers	Proactive Replacement based upon Condition Results or Refurbishment	Padmount transformers are replaced when asset health, safety risks, severe corrosion, and oil leaks occur, or upon failure. Functional but cosmetically deteriorated units may be refurbished in place to extend service life.
Padmount Switches	Proactive and Reactive Replacement	Padmount switches are replaced when they fail in the field, or proactively when asset health or deficiencies are encountered such as anomalous infrared (IR) scan results and the potential impact of failure on system reliability and restoration times.
Polemount Transformers	Proactive and Reactive Replacement	Polemount transformers are replaced when they fail in the field, or proactively when elevated failure risk, based on inspections, age, corrosion, and oil leaks are observed to reduce reliability and environmental risks. Load growth and electrification may result in an overhead transformer being replaced to address capacity constraints.
Substation Power Transformers	Proactive Replacement	Substation power transformers are replaced when they fail or when condition assessment (dissolved gas analysis, insulation testing, oil quality, loading history) indicates early signs of failure, or when obsolescence prevents safe and reliable operation. Replacement

Asset Class	Primary Intervention Strategy	Description
		prioritization considers asset health index, safety risk, environmental risk, and number of connected customers.
Substation Circuit Breakers	Proactive Replacement	Replaced based on operability and condition assessment. Obsolete models without spare parts are prioritized for renewal during substation upgrades.
Substation Switchgear	Proactive Replacement	Replaced based on operability and condition assessment. Inspections and lubrication extend life, but major defects trigger replacement.
Battery Banks and Chargers	Proactive Replacement	Replaced when impedance testing or inspection shows significant degradation to ensure protective devices operate during outages.
Underground Cables – In Conduit	Proactive Replacement	Entire cable segments are replaced upon failure or when insulation tests indicate end-of-life deterioration.
Underground Cables – Direct Buried	Proactive Replacement, Rehabilitation & Reactive Repair	Direct-buried cables can be proactively replaced with new cables-in-conduit or rehabilitated using cable injection technologies. When these cables fail, the only available intervention is to locate the failed cable, excavate & cut out the failed section and install a polymeric splice to restore the cable to service.

Asset Refurbishment Practices

In addition to full replacement, Elexicon employs targeted refurbishment to extend the life of assets where technically and economically feasible. The decision to refurbish rather than replace is based on:

- Comparative cost and expected life extension versus replacement.
- Asset failure risk based on Heath Index, Age and inspection report.
- Availability of parts and compatibility with current standards.
- Impact on safety, reliability, and environmental risk.
- Asset accessibility and coordination with planned projects.

Examples of Elexicon's refurbishment practices include:

- **Padmount Transformers:** Rusted enclosures are sanded, primed, and repainted in place to prevent oil tank perforation and environmental contamination, avoiding unnecessary capital replacement where internal components remain in good condition.
- **Direct-Buried Cables:** Where testing shows sufficient remaining insulation life, dielectric fluid injection is used to rehabilitate cable performance. This approach defers full replacement and reduces capital costs, while reactive splicing addresses localized faults.
- **Switchgear and Breakers:** Live-front switchgear is cleaned using CO_2 dry ice cleaning, and defective components are replaced where possible. Breakers with operable mechanisms but deteriorating contacts may be overhauled, with obsolete units retained for spare parts to support others in service.
- **Substation Transformers:** Transformers may undergo component-level refurbishment, such as paint touch ups, gasket replacement, or oil top ups, where economically justified and condition permits.

Elexicon's refurbishment approach allows the utility to defer major renewals, maintain compliance, and optimize lifecycle costs without compromising safety or reliability. Where refurbishment is not feasible due to condition, obsolescence, or safety considerations, full replacement is undertaken.

2. DESCRIPTION OF MAINTENANCE AND INSPECTION PRACTICES

The distribution system maintenance segment ensures that Elexicon can reliably and efficiently deliver electricity to its customers through a full suite of inspection, maintenance, repair, and restoration activities performed across the utility's distribution and substation assets. These activities are essential for sustaining asset performance over their expected service life, mitigating system risks, and ensuring that the system operates safely, reliably, in an environmentally responsible manner, and in full compliance with applicable legislative and regulatory requirements, including the *Ontario Energy Board's Distribution System Code* (DSC).

Inspection and maintenance programs are a critical component of Elexicon's Asset Management process. They are designed to assess asset condition, identify risks to safety, reliability, or the environment, and

implement timely corrective actions. The primary objective is to prevent premature asset failure, extend asset life, and minimize lifecycle costs while ensuring the continued safe and reliable delivery of electricity to customers. This is discussed further in the OM&A Overview for “Maintenance – Distribution System” & “Maintenance – Substations" (See Exhibit 4 - Tab 1 - Schedule 1).

Elexicon’s inspection and maintenance cycles are determined using two main drivers:

- Regulatory requirements as defined by the DSC’s minimum inspection schedules; and
- Condition-based assessment (CBA), which evaluates actual usage, expected life, physical condition, probability of failure, and potential safety, reliability, and environmental impacts.

Work is scheduled, where possible, during lower capital construction periods such as the winter months to optimize resource allocation and maintain consistent O&M expenditure throughout the year.

Table 2: Summary of Inspection and Maintenance Activities

Asset Class	Category	Activity	Frequency
Overhead Distribution	Predictive	Visual Patrol	3-year cycle
Overhead Distribution	Predictive	IR Thermography	Annually
Overhead Distribution	Preventative	Insulator Washing	1–2 times annually (targeted zones)
Wood Poles	Predictive	Pole Testing	After 10 yrs, then every 3 yrs
Padmount Transformers	Corrective	Rust Painting/Graffiti Removal	Annually
Padmount Transformers	Predictive	External/Internal Inspection	3-year cycle
Transformer Vault	Predictive	External/Internal Inspection	3-year cycle
Overhead Switches	Preventative	Cleaning, Lubrication, Testing	3-year cycle
Underground Cables	Predictive	Cable Testing	As required
Submarine Cable	Predictive	Cable Inspection	3-Year Cycle
Switchgear	Predictive	IR Thermography	3-year cycle
Switchgear	Preventative	Cleaning, Lubrication, Testing	3-year cycle
Substation Transformers	Predictive	Visual & Thermal Inspection	Monthly
Substation Transformers	Preventative	Oil Sampling & Analysis	Annually
Substation Breakers & Relays	Preventative	Testing & Calibration	3-year cycle
Battery Systems	Preventative	Impedance Testing & Cleaning	3-year cycle

3. PROCESSES AND TOOLS TO FORECAST, PRIORITIZE & OPTIMIZE

3.1 Renewal Forecast, Optimization and Prioritization

Elexicon's asset maintenance and capital renewal programs are designed to ensure that assets are maintained and replaced based on data driven results from condition assessments and typical useful life analysis, while also strategically incorporating enhancements to meet current and future capacity needs. This approach minimizes the risk of premature asset replacement, enables new customer connections and load growth, and supports Elexicon's broader goals of reliability, efficiency, customer service, and sustainability.

As Elexicon's operating environment has evolved into a more dynamic and growth-oriented context driven by rising customer load demand and accelerating electrification, Elexicon has advanced its planning practices to ensure that targeted investments continue to enhance system capacity. These refinements support the needs of a growing and increasingly electrified local economy, ensuring that high-growth areas maintain appropriate service levels while also enabling continued integration of DERs and supporting the electrification objectives of customers.

As outlined in Exhibit 2B - Tab 3 - Schedule 1, Elexicon performs standardized risk assessments across a range of projects, providing an objective ranking of each project's contribution to Elexicon's asset management objectives. Project planners select from a set of potential impact and probability outcomes aligned with these objectives. This approach ensures a uniform and transparent process for evaluating and prioritizing projects.

Elexicon's project prioritization is guided by a structured criticality-based framework to ensure that investments are directed toward areas of highest need, balancing risk, reliability, customer impact, and regulatory compliance. For each investment category, projects are prioritized leveraging relevant inputs as detailed in Table 3. This process ultimately ensures that capital investments are selected and sequenced based on objective, risk-informed criteria, thus ensuring that projects addressing the highest system risks, customer impacts, and operational constraints are advanced first.

Table 3: Summary of Prioritization Inputs per Investment Category

Investment Category	Relevant Inputs used for Prioritization
System Renewal	• Probability Assessment (Asset Condition, Historical Performance, Legacy/Non-Legacy Assets) • Impact Assessment (Financial, Reliability, Safety & Environmental impact dimensions)
System Service	• Contribution to System Reliability, Resiliency, Automation, Visibility & System Efficiency. • Substation Growth Projects: Load Forecast & Capacity Analysis • Voltage Conversion Projects: Feeder capacity utilization, asset condition, asset age, risk of failure, safety concerns, redundancy limitations
System Access	• Mandatory to accommodate new customer connections or third-party requirements
General Plant	• Operational necessity, safety, and enablement of core business functions, including: o End-of-life condition, o Compliance with safety or regulatory standards, o Asset criticality to maintaining day-to-day operations and supporting field work.

3.2 Strategies for Operating within Budget Envelopes

Elexicon employs a balanced approach to ensure that capital investments remain within approved budget envelopes while continuing to address reliability, safety, and customer needs. Execution work planning provides visibility into project schedules, costs, and progress across all investment categories, including a structured change request process to maintain project control and governance. Projects are prioritized based on established criteria outlined in Exhibit 2B - Tab 3 - Schedule 1, which consider factors such as asset condition, risk reduction, regulatory compliance, and customer impact. Non-discretionary projects including customer connections, system access, and mandated reliability or safety work are prioritized first

to ensure essential obligations are met before discretionary renewal and enhancement projects are advanced.

Throughout the year, Elexicon's Program Delivery Group (PDG) conducts regular reviews of the capital and maintenance work programs to assess progress of planned work, spending performance and adjust pacing or scope as needed. This process allows Elexicon to reallocate resources in response to emerging needs, such as unplanned failures or storm-related restoration costs that exceed reactive capital budgets. This structured, adaptive approach ensures that Elexicon continues to operate prudently within its budget envelopes while delivering value to customers and maintaining system reliability.

4. IMPORTANT CHANGES TO LIFE OPTIMIZATION POLICIES AND PRACTICES SINCE LAST DSP FILING

Since the last DSP filing, Elexicon's life optimization policies and methodologies have remained consistent, following a risk-based approach that balances asset condition, performance, and lifecycle cost considerations. While no major changes have been made to the underlying policies and practices, Elexicon has enhanced the supporting data and processes that inform life-optimization decisions.

In particular, improvements to asset data collection, including standardized inspection forms, digital field data capture, and integration with the GIS and Asset Repository, have increased the accuracy and completeness of information used to assess asset health and remaining life. These refinements strengthen the confidence of Elexicon's existing optimization framework and enable more reliable forecasts of end-of-life timing and more defensible investment decisions.

SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION & DISTRIBUTED ENERGY RESOURCES

1. APPLICATIONS FOR RENEWABLE GENERATORS OVER 10 KW

Table 1 lists the only current application from renewable generators over 10 kW for connection to Elexicon's service area. The applications are part of the Net-Metering and Load Displacement program.

Table 1: List of REG Applications over 10 kW

Feeder	Municipality	Type	Capacity (kW)	Estimated Connection Year
8M3	Belleville	Solar PV	990.1	2026
40M5	Whitby	Solar PV	300	2025
81M7	Ajax	Natural Gas	2000	2026
8M10	Belleville	BESS	11,563.2	2027
REID-F1	Belleville	Solar PV	45	2025
SQUI-F1	Pickering	Solar PV	60	2026
40M46	Ajax	Solar PV	250	2025
DOWT-F4	Ajax	Solar PV	90	2026
SQUI-F4	Pickering	Solar PV	200	2026
Total Capacity (kW)			15,498.3	

2. FORECAST OF REG CONNECTIONS

Table 2 presents Elexicon Energy's forecast of REG connections over the 2025 to 2031 period. The forecast reflects anticipated trends in both the number of applications and total capacity based on current activity, active applications, and information available regarding expected renewable development within Elexicon's service territories. This provides a consolidated view of projected REG uptake across the forecast horizon.

Table 2: REG Applications and Connection Forecast

	REG Connection Forecast							
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
# of Applications	41	50	48	46	48	47	47	327
Capacity (kW)	2,401.7	2,892.3	14,271.8	2,688.6	2,784.3	2,748.2	2,740.4	30,527.3

3. RESTRICTED FEEDERS

Table 3: Available Capacity at the Transformer Substations for REG Connection

Substation Name	Feeder Designation	Reason for Restriction
Whitby TS 27.6 kV	40M-45	Whitby TS 27.6 kV BY Bus has reached its short-circuit capacity. As a result, additional DER connections on these feeders are restricted.
	40M-46	
	40M-47	
	40M-48	
Sheppard TS DESN 2	47M-2	Sheppard TS DESN 2 bus has reached its short-circuit capacity. As a result, additional DER connections on these feeders are restricted.
	47M-4	

The concentration of DERs on Elexicon's distribution feeders remains relatively low, therefore, no system-wide upgrades are currently planned. All feeders, with the exception of the six restricted feeders noted above, have sufficient capacity to accommodate additional DER connections. For the Whitby TS 27.6 kV BY Bus and Sheppard TS DESN2 Elexicon is currently exploring options for increasing the short-circuit capacity at the bus. Enhancing the short circuit capacity at these substations would enable greater DER integration on restricted feeders.

4. CONSTRAINTS – DISTRIBUTION AND UPSTREAM

Short-circuit capacity limitations have been identified at the bus level of Whitby TS (DESN 1) and Sheppard TS (DESN 2). These substations supply six of Elexicon's 27.6 kV feeders: 40M45, 40M46, 40M47, and 40M48 from Whitby TS, and 47M2 and 47M4 from Sheppard TS. Elexicon will explore potential solutions to increase the available short-circuit capacity. Increasing this capacity will support future feeder expansion and enable the connection of additional DER projects.

5. CONSTRAINTS – EMBEDDED DISTRIBUTOR

Aside from the constraints identified above in Section 4, there are currently no other limitations on Elexicon's system. However, with the continued growth of DER penetration on Elexicon's feeders, potential future challenges are anticipated, including thermal capacity constraints, protection & coordination complexities, power quality concerns, and voltage regulation issues.

NON-WIRES SOLUTIONS TO ADDRESS SYSTEM NEEDS

1. OVERVIEW

The Ontario Energy Board released the Non-Wires Solutions (NWS) Guidelines for Electricity Distributors in March 2024[1]. These Guidelines set out the expectation that distributors are required to incorporate consideration of NWSs into their distribution planning processes. The Guidelines stipulate: "Recognizing that distribution system planning may be at a relatively advanced stage for applications scheduled to be filed in 2024 or 2025, the OEB's expectation is that all rate applications filed in 2026 should be fully consistent with the BCA Framework."[1]

Given that Elexicon's rebasing application was filed in 2025, Elexicon has taken deliberate steps to prepare for full alignment with the Guidelines by initiating work that strengthens its planning processes and supports the disciplined assessment of NWS alternatives.

2. BINARY SCREENING PROCESS

To ensure readiness for the 2026 requirements, Elexicon is completing the necessary pre-assessment activities prescribed by the Guidelines, including screening of system needs and the preparation of BCA evaluations for those investments that pass through the pre-screening framework. These analyses will be submitted later on in the application process.

Elexicon recognizes that NWS will play an increasing role in long term system planning and that the disciplined evaluation of potential NWS opportunities must be supported by structured processes, improved data, and alignment with broader asset management objectives. To support this evolution, Elexicon engaged specialized external expertise to design a pre-screening framework suited to the characteristics of Elexicon's distribution system, the investment portfolio under review, and the practical constraints associated with NWS deployment. The resulting framework provides a staged method for identifying system needs where NWS may have a reasonable likelihood of technical and operational feasibility. The framework also clarifies where NWS cannot satisfy the underlying requirement, such as

[1] EB-2024-0118, "OEB - Non-Wires Solutions Guidelines for Electricity Distributors", (March 28, 2024)

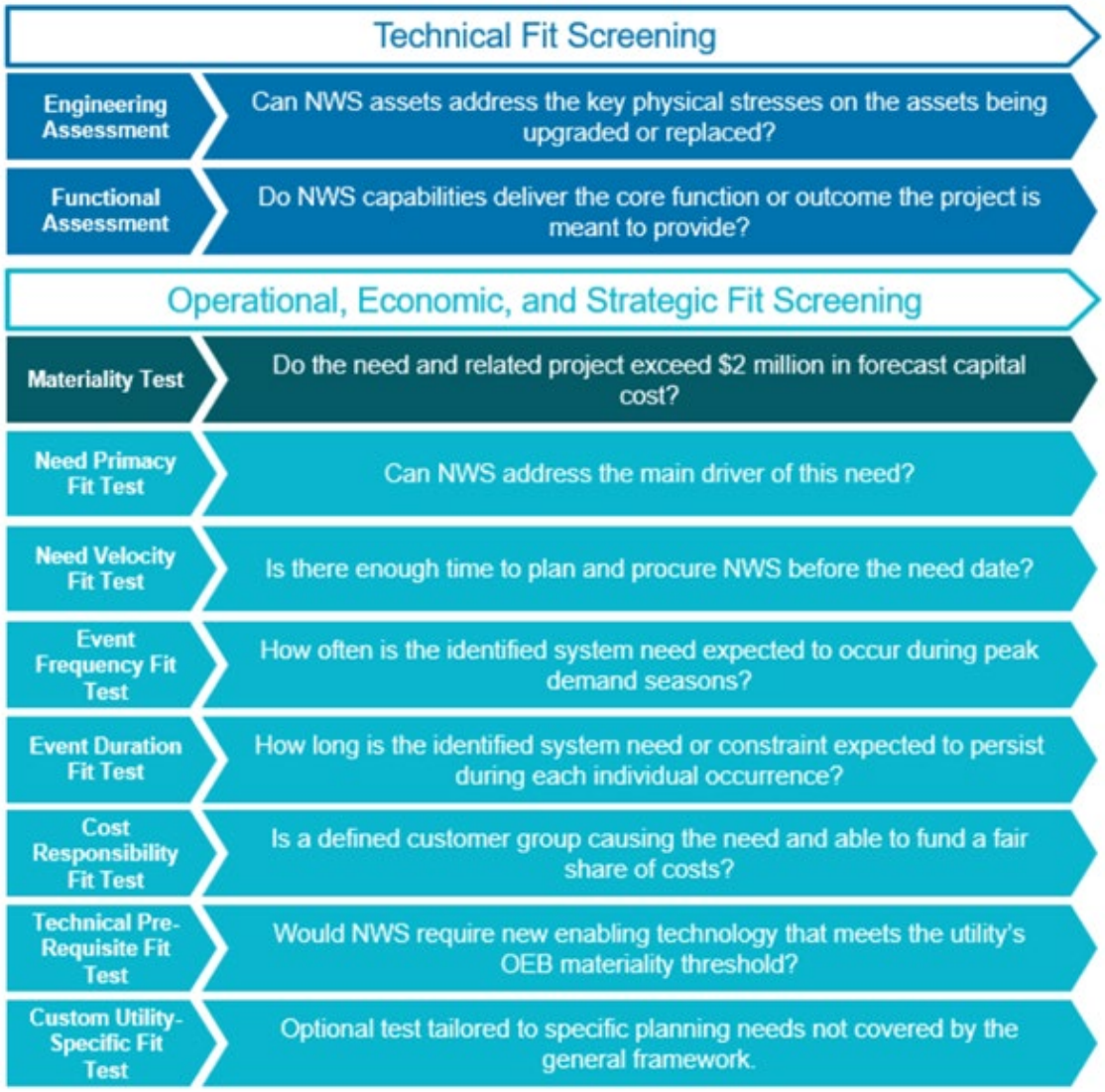
needs driven by asset condition, safety, or other physical system modifications. A report detailed the work performed by the external expert can be found in the "NWS Pre-Screening Methodology Summary" (See Exhibit 2B - Tab 3 - Schedule 5 - Appendix A).

This preparatory work reflects Elexicon's commitment to strengthening the asset management system by ensuring that planning decisions consider a full range of alternatives and by promoting consistency in how options are evaluated. The pre-screening framework also provides early insight into areas where Elexicon may need more operational visibility, and data management capabilities to be able to efficiently develop and deploy NWS.

Elexicon sought a pre-screening framework that ensures the utility is assessing only those system needs where an NWS is a viable alternative, thus applying its planning resources efficiently. However, Elexicon recognizes this framework will evolve as the availability, technical capabilities, and cost-effectiveness of NWS is enhanced.

Figure 1 below illustrates the NWS pre-screening framework that was developed.

Figure 1: Non-Wires Pre-Screening Framework



As Elexicon continues to advance its asset management system, the pre-screening framework will form the foundation for how NWS opportunities are identified and assessed in future planning cycles. The intent is to maintain a stable and repeatable methodology that evolves to reflect new regulatory expectations, improved data, or material changes in industry practice. This provides long-term consistency for evaluating potential NWS investments and allows for the same core framework to remain applicable in future DSPs, thereby ensuring predictable and transparent treatment of system needs over time.

Elexicon applied the pre-screening framework to all capital investments within the 2027-2031 DSP that fall within the scope of the NWS Guidelines. Each investment was examined through a series of technical and planning criteria designed to determine whether an NWS could reasonably contribute to meeting the identified need. Through this process, the majority of investments were screened out due to lack of technical fit or because NWS would not address the primary drivers for the investment. Three investments, representing approximately $34.33M in capital spending, met the conditions necessary to warrant detailed Benefit Cost Analysis. This analysis can be found in the "2027-2031 DSP NWS Pre-Screening Results" (Exhibit 2B - Tab 3 - Schedule 5 - Appendix B).

The projects that progressed beyond pre-screening share characteristics that support the potential applicability of NWS. These needs are driven primarily by electrical loading rather than asset health, occur in locations where NWS could potentially provide measurable system benefit, and provide sufficient lead time to support the development, procurement, and deployment of an NWS resource.

3. FURTHER ANALYSIS AND DEVELOPMENT

Elexicon will develop and assess the specific NWS alternatives applicable to each of the pre-screened projects. This step is necessary to identify a technically credible and operationally feasible NWS option against which the conventional investment can be compared. Once the potential NWS options are defined, Elexicon will proceed with the BCA to evaluate their relative merits, costs, and system benefits in accordance with the OEB's framework.

On this basis, Elexicon is advancing these investments to detailed Benefit Cost Analysis to determine whether an NWS may offer a viable and cost-effective alternative to the corresponding conventional solution. These investments include:

- Bradshaw MS Capacity Upgrade - Substation Growth (approx. $8.47M) - driven by capacity constraints forecasted in the Bowmanville area.

- Feeder Capacity Enhancements - Grid Enhancements (approx. $14.83M) – integrate new capacity, alleviate thermal constraints, and strengthen system redundancy to support future load growth[2].
- Undersized Conductors - Grid Enhancements (approx. $11.28M) - replace approximately 36 km of undersized conductor wire on main feeder trunks in areas with capacity and contingency constraints.

Upon completion of the BCA, Elexicon will evaluate whether any of the candidate investments demonstrate a favourable or near-favourable outcome. If the analysis confirms that an NWS provides comparable or greater net present value relative to the traditional solution, Elexicon will determine whether and how the NWS can be integrated within the 2027 to 2031 investment plan.

Elexicon will report the outcomes of these assessments within this application and through future investment planning cycles.

With the NWS pre-screening framework established, Elexicon will incorporate this methodology into the asset management planning process to ensure that NWS considerations are evaluated consistently and transparently in future distribution system investment decisions. This integration advances alignment with the OEB's Guidelines and the BCA Framework and creates a foundation for ongoing improvement as NWS capabilities, data, and market conditions evolve.

4. LIST OF ATTACHMENTS:

- Appendix A: NWS Pre-Screening Methodology Summary
- Appendix B: 2027-2031 DSP NWS Pre-Screening Results

[2] A portion of the distribution capacity and reliability enhancements have been screened out in the process, corresponding to $20.14M removed.

EXHIBIT 2B - TAB 3 - SCHEDULE 5: APPENDIX A
NWS PRE-SCREENING METHODOLOGY SUMMARY

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Elexicon Energy Inc.

Non-Wires Solutions (NWS) Pre-Screening Methodology Report

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Date: December 5, 2025

CRA Project No. 104025

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1. Executive Summary

Context

On March 28, 2024, the Ontario Energy Board (OEB) released the *Non-Wires Solutions Guidelines for Electricity Distributors* ("the NWS Guidelines"), a policy document which outlines new requirements that distributors must follow in integrating Non-Wires Solutions (NWS) into capital allocation decisions. The NWS Guidelines make explicit the need for Ontario distribution utilities to document their consideration for NWS for capital investments greater than $2 Million and to conduct Benefit-Cost Analysis (BCA) for any NWS that is identified as a potentially viable solution to the investment need at hand.

In response to this policy, Elexicon Energy Inc ("Elexicon") engaged Charles River Associates International (CRA) to develop an NWS pre-screening framework for application to its planned capital investments. This report summarizes the process and source information CRA relied on in developing the framework we ultimately recommended to Elexicon and which the company subsequently asked us to apply to its 2027-2031 Distribution System Plan ("DSP") investments. Addendum A to this report details our process and findings of applying the pre-screening framework to the specific investments that Elexicon plans over the relevant time horizon.

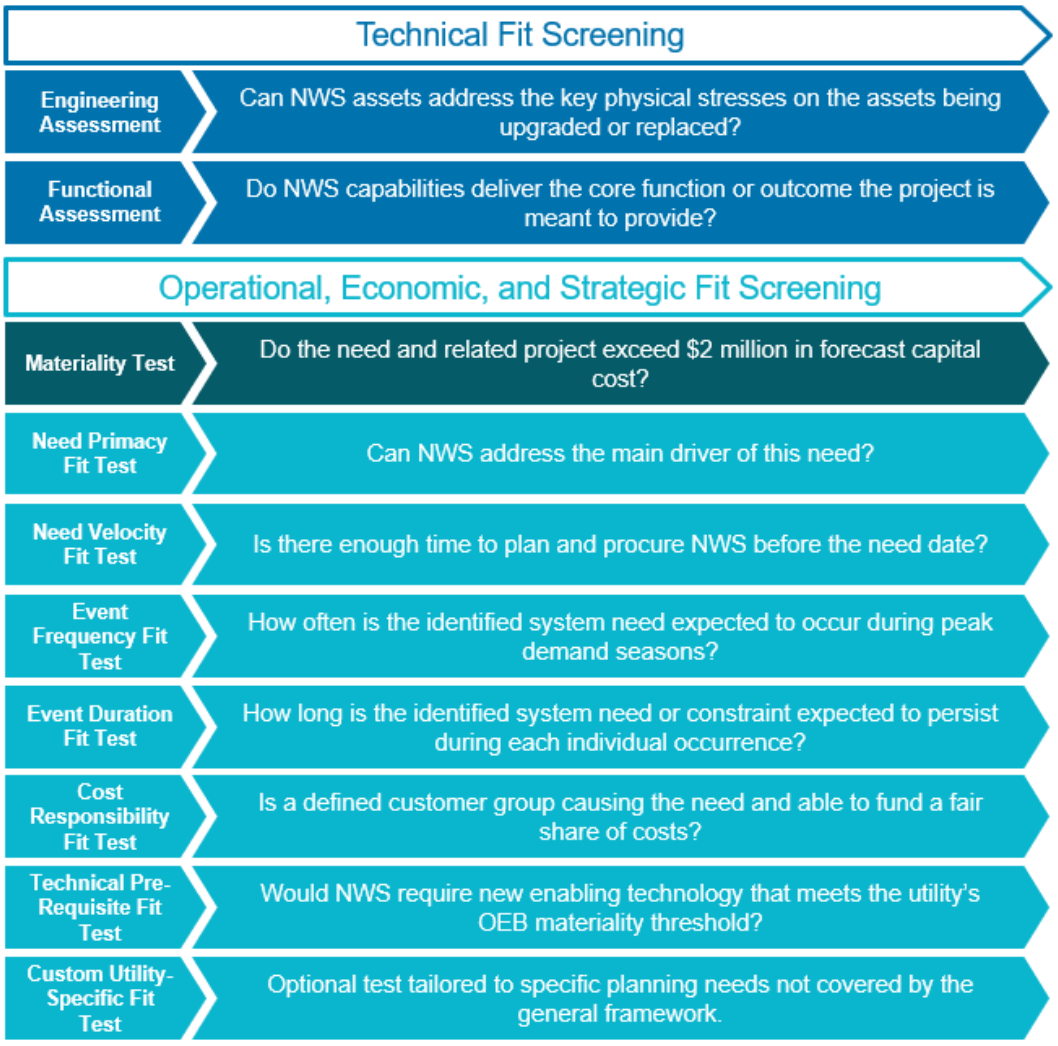
Framework Development Process

CRA initiated the development of the NWS pre-screening framework by interviewing technical and regulatory subject matter experts from Elexicon and three other large Ontario distributors – namely Hydro One Networks Inc. Hydro Ottawa Limited, and Toronto Hydro Electric System Limited. Our interviews aimed to explore how NWS considerations were incorporated into their existing planning processes and what (if any) tools or processes were in place to support NWS planning and management. We relied on these insights to ensure that the framework we recommended was sufficiently simple and pragmatic to account for the baseline capabilities in place to date, while encouraging continuous improvement.

In parallel with our interview work, CRA conducted a jurisdictional scan where we examined multiple NWS pre-screening frameworks implemented by utilities in the United States. We also reviewed in detail the Independent Electricity System Operator's (IESO) "*Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*" document, and Enbridge Gas Distribution Inc.'s "*Integrated Resource Planning (IRP)*" framework – as both Ontario frameworks were explicitly listed as instructive examples in the OEB's NWS Guidelines. By considering screening test examples from other jurisdictions against those listed as foundational Ontario examples, we sought to balance our best practices with local experience.

Consistent with our interpretation of the OEB's NWS Guidelines, we sought to devise a screening framework that ensured that NWS opportunities were considered with maximum rigor in relation to system needs where they were expected to provide the greatest value. To this end, when designing our framework, we envisioned a funnel-like approach, where a progressively smaller portion of system needs (and the conventional investments that typically address them) are exposed to progressively more nuanced and rigorous screening parameters. In our view, the first step in enabling such an approach involved designing a test that efficiently screened out the needs and investment types that rely on functions that NWS solutions are physically incapable of undertaking. Beyond this initial step, it was also reasonable to screen out the investment needs where NWS could provide some value (e.g. addressing a secondary driver) but could be expected to address the primary driver of the need. Upon applying these two sets of screens meant to capture investments where NWS could provide no value, or only marginal value, it was, in our view, reasonable to proceed to more nuanced criteria that explored the fit between specific investment needs and NWS solutions. Figure 1 on the following page provides a visual summary of the pre-screening framework we recommended to Elexicon and ultimately applied to its 2027-2031 DSP.

Figure 1: NWS Pre-Screening Framework



The framework starts with a two-part Technical Fit Screening phase designed to eliminate investment needs and their associated traditional solutions where NWS could not offer a practical alternative due to the lack of the requisite functional and technical capabilities. We developed this test by compiling a generic list of common investments that distributors typically undertake. For each type of investment on our generic list, we defined a core functional outcome that must be met to address the need in question and then examined whether NWS could attain such outcomes given their technical features and functional capabilities.

As an added layer of technical fit analysis, we examined whether and to what extent the investments on our generic list were affected by what we saw as two primary modes of asset degradation – namely Mechanical Stress and Electrical Loading. We concentrated on these two types of asset stressors because one or both apply to the majority of System Access, System Renewal, and System Service investments, and in our view, enable a near-binary categorization based on whether NWS can or cannot offer a reasonable alternative. Where Electrical Loading is a significant investment driver, all commercial types of NWS can be reasonably expected to provide an alternative in the form of downstream load relief. On the contrary, where Mechanical Loading is the main investment driver, NWS are not equipped to

provide any long-term alternative – even if they can temporarily reduce the impact of mechanical failures that investments seek to prevent.

In assessing the degree of Mechanical Stress and Electrical Loading relevant to the list of typical distribution investments, we consulted the 2010 *Asset Depreciation Study for The Ontario Energy Board* developed by Kinectrics Inc. ("the Kinectrics Report"), which (amongst other important insights) provides such an assessment. We concluded that application of the Technical Fit Screen would likely result in the removal from further consideration of virtually all programs driven by asset lifecycle management needs (System Renewal investments) and most programs associated with externally driven requests (System Access investments).

For the programs that remained beyond this initial threshold test, we then constructed a set of six progressively more nuanced and information-intensive Phase 2 screens that we describe in more detail in the body of this report. At the outset of Phase 2, we also proposed screening out the projects that were estimated to require a total investment below $2 million over the relevant DSP period. Finally, at the very end of our framework, we proposed an optional, seventh screen that could reflect a custom, utility-specific condition that a distributor may believe is relevant in addition to those contemplated in our framework.

2. Introduction

2.1. Our Mandate

Charles River Associates International ("CRA") is pleased to present this report to Elexicon Energy Inc. ("Elexicon") following an engaging and collaborative research and framework development effort. Elexicon retained CRA ahead of filing its 2027-2031 DSP to recommend an NWS pre-screening framework that aligned with the Ontario Energy Board's ("OEB") guidance provided in its March 28, 2024, *Non-Wires Solutions Guidelines for Electricity Distributors* ("the NWS Guidelines"). In this report we summarize the research process, input parameters and analytical considerations that ultimately shaped the pre-screening framework we recommended to Elexicon, and which we then applied to its 2027-2031 DSP investments, as detailed in Addendum A to this report.

2.2. Our Process

In this engagement, CRA reviewed Ontario's NWS policy guidance and precedents, surveyed leading North American jurisdictions that already use NWS screening tools, and met with Elexicon technical SMEs and those from several other large Ontario distributors, namely Hydro One Networks Inc., Hydro Ottawa Limited, and Toronto Hydro-Electric System Inc. During our meetings we explored current and planned decision support tools and territory-specific characteristics that shape NWS opportunities and constraints that they saw. Taken together, this gave us a three-part foundation for our recommendations:

- Analysis of relevant parts of Ontario's regulatory framework,
- Instructive screening examples from other jurisdictions, and
- Operating context insights from several large Ontario distributors.

Using these insights as described below, we developed a multi-gate NWS pre-screening framework for Elexicon to apply to its 2027-2031 DSP. As the following sections showcase, the framework is grounded in research and provides multiple opportunities for customization of threshold criteria that Elexicon's SMEs can adjust to better fit their system planning context.

2.3. Report Structure

The remainder of this report is structured as follows:

- Chapter 3 explores the key tenets of Ontario's current policy and technical landscape related to the issue of NWS, including the OEB's NWS Guidelines, and the pre-screening frameworks designed by Enbridge and the IESO. The Chapter also summarizes our key insights as to the features that we believe a successful Ontario electricity distribution-specific NWS screening approach should include.
- Chapter 4 relays the insights of our North American cross-jurisdictional scan and summarizes the key takeaways from our interviews with the members of planning, asset management, and regulatory staff of Elexicon and other Ontario distribution utilities mentioned above.
- Chapter 5 defines and substantiates the phases and individual inputs comprising our recommended screening framework.

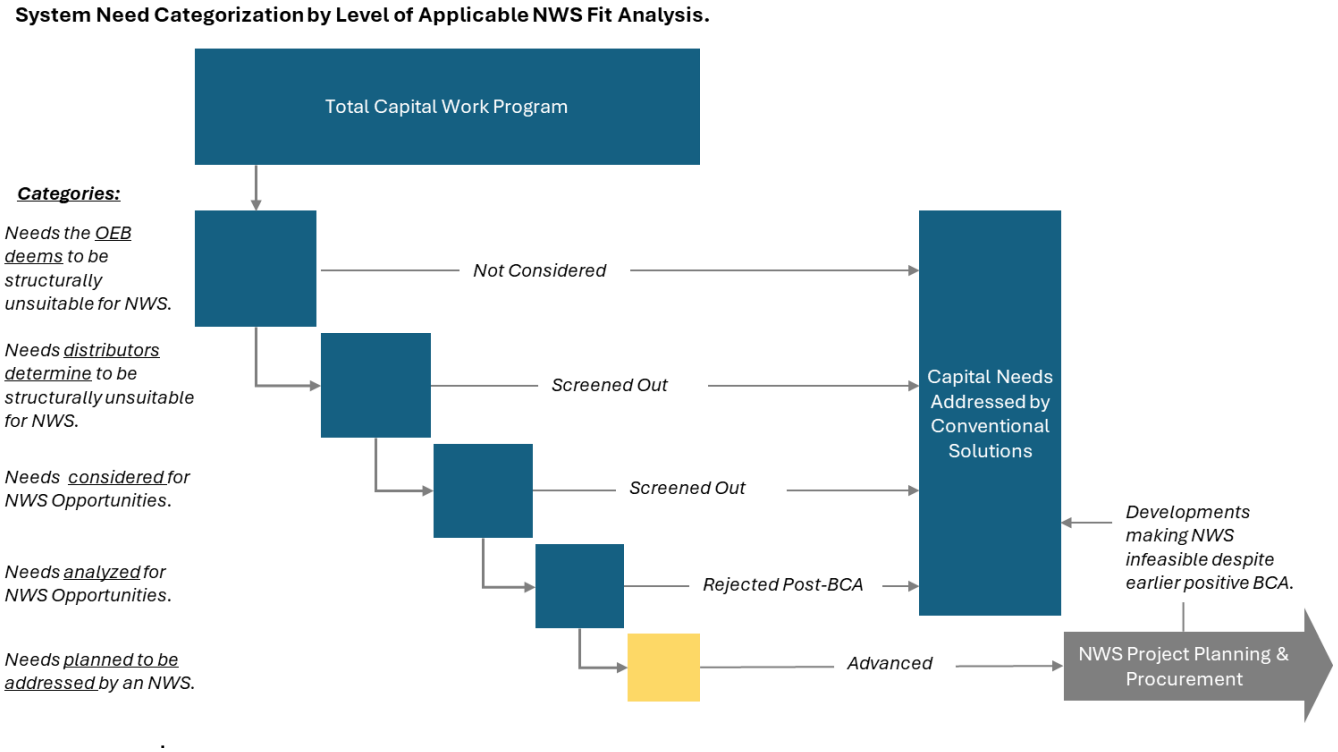
3. Non-Wires Solutions in the Local Regulatory Setting: Impact of the Overall Framework and Key Implications of Specific Guidance

3.1. The NWS Guidelines: Key Tenets and Their Influence on Our Objectives

The OEB's *Non-Wires Solutions Guidelines for Electricity Distributors* provide a clear, practical framework for how distributors should consider NWS in a variety of contexts, including those that go beyond our immediate purposes, such as participation in regional planning and conservation and demand management (CDM) initiatives.

In substance, the NWS Guidelines imply a hierarchy of investment needs captured in Figure 2. Some are *structurally* unsuitable for NWS (for example General Plant IT/OT, fleet, and facilities), some can be classified as unsuitable based on technical evaluation. Others are theoretically addressable by NWS but can still be screened out before a full benefit cost analysis even if they exceed the $2 million materiality threshold. The final subset proceeds to BCA, where NWS options can also be rejected if they are found to be less economic than traditional solutions, if NWS procurement leads to uneconomic results, if unexpected load growth erodes the value of deferral, or if a traditional solution is preferred by customers who drive the need with their requests. The figure below illustrates these eventualities to underscore the importance of designing an NWS framework that can efficiently test and screen out for a variety of scenarios, so that only projects where NWS offers the best potential value proceed to more data- and effort-intensive analysis.

Figure 2: System Need, Program and Project Categorization by Level of Applicable NWS Analysis



System Needs / Use Cases Explicitly Contemplated

The *NWS Guidelines* give one explicit example of a potentially rate-funded NWS: solutions that reduce instantaneous demand (kW or kVA) on a distributor's system or a portion of it. They list common NWS types but no further use cases, and state that the examples are not exhaustive to allow for innovation. For screening purposes, this reinforces the need for a structured functional assessment of core distribution assets and interventions over their lifecycle, so that plausible NWS applications are not overlooked.

Assessment Depth vs. Anticipated Benefits

The Guidelines state that the degree of NWS consideration should be proportional to their expected benefits. CRA interpreted this criterion in practical terms: projects where NWS can address a primary need driver should receive deeper assessment, while those where NWS affects only secondary or tertiary drivers can undergo more cursory review before being eliminated. As a hypothetical example, while an aging station power transformer found to be in Poor condition may benefit from capacity relief that a downstream NWS could provide should load growth be expected in the area it serves, the NWS would not be able to address the risk imposed by the unit's overall condition. In our view, this means that NWS would not be a suitable alternative for an investment like our hypothetical power transformer.

Degree of Consideration Depending on Distributor Size or Resources

The OEB Guidelines acknowledge that the extent of NWS consideration may vary with distributor size and resources. Considering the large distributors we interview, the differences in their scale, customer mix, and existing tools may mean that they have different baseline capabilities for NWS deployment. For our pre-screening framework, this suggests that: (i) numerical thresholds should leave room for utility-specific customization, (ii) any incremental enabling investments needed to support NWS should be treated as part of the NWS cost base, and (iii) an optional utility specific-criterion may be appropriate to reflect a given maturity level or specific strategic preferences.

Consideration of Customer Preferences in Customer-Specific NWS Scenarios

For customer-driven needs, the Guidelines encourage consideration of NWS, but instruct distributors to respect expressed customer preferences, including willingness to pay for a traditional solution (if relevant). This both broadens the set of potential NWS applications and limits NWS use where customers clearly favour conventional options. While it could be expedient to screen out all customer-driven projects at an early stage of a framework based on this guidance, CRA believes that it is more transparent to apply other technical and operational tests before finally assessing whether the remaining needs are driven by specific customers.

Pre-Screening Process Mechanics

There are multiple potential ways of presentation and levels of complexity in which the NWS pre-screening approach could be structured. In CRA's assessment, however, the fact that the OEB chose the Enbridge IRP and the IESO IRRP screening frameworks and specifically called out their "binary" nature in the NWS Guidelines can be taken as an indication of the regulator's expectation that screening frameworks should be relatively simple and efficient in application.

Having previously mentioned the OEB's framing of the IESO's and Enbridge's existing investment screening frameworks as being instructive for distributors, we now turn to briefly discuss their most salient features.

3.2. The IESO IRRP Screening Framework

The IESO's 2023 "*Integrated Regional Resource Planning Screening Framework: A Guide for Assessing Non-Wires Alternatives*" framework uses a three-stage, binary screening process where options can be eliminated at any gate rather than scored and ranked. Screen 1 is a simple Yes/No matrix that tests four NWS options (which the IESO calls Non-Wires Alternatives) against five need types. Of note, all four options are marked "Yes" for End-of-Life needs, which the IESO clarifies refers to *right-sizing* and coordinating asset replacement – *not* avoiding replacement altogether. Screen 2 applies high-level traits such as size of need and coincidence with system peak, using simple thresholds, and only considers NWS to the extent they can fit within existing system's capacity. Screen 3 provides flexibility for special, location- or utility-specific circumstances. The framework also notes a minimum NWS implementation timeline of two years.[1] Our key takeaways from the review of the IESO framework were its simplicity, binary nature and the implied expectation that if the existing system could not accommodate NWS to the requisite extent, this fact qualified as ground for removing NWS from further consideration.

3.3. Enbridge's IRP Screening Framework

Enbridge's binary Integrated Regional Planning (IRP) screening framework determines whether a system need should undergo IRP evaluation or proceed through conventional capital planning process. It applies five screens that can remove a need from further IRP consideration: emergent safety issues, very short timelines (needs that must be met in under three years), customer-specific builds, and needs driven by community expansion or economic development policy. The treatment of customer-specific needs is consistent with the OEB's expectation of customers responsible for the investment being given discretion to the use of NWS vs. traditional solutions. The three-year threshold is conceptually similar to the IESO's two-year minimum NWS timeline, although Enbridge uses it more explicitly as a cut-off. In our view, the community expansion criterion also supports screening out all Capacity Allocation Model (CAM)-eligible projects out of NWS consideration, given their policy origin and the added time and uncertainty associated with NWS procurement in the environment where multiple sets of customers would connect (and thus potentially wish to express their preference) over time.[2]

3.4. Key Takeaways for the Pre-Screening Framework

Having explored the key documents that convey the OEB's expectations as to the form and function of a potential NWS pre-screening framework, we advanced the following five objectives that we see as both being consistent with the available policy guidance, and being in line with Elexicon's objectives underlying our engagement:

Application Transparency and Simplicity: it is, in our view, critical for an effective pre-screening framework to be intuitive, transparent, and easy to apply. While this need not imply that the issues it captures or thresholds it sets are themselves products of simple considerations, we were compelled to ensure that the nature and structure of our evaluation tiers is transparent and ease of use.

A Hybrid of Program- and Project-Level Evaluations: we believe that it is consistent with the OEB's guidance to develop a pre-screening framework that starts out with a higher-order program-level need evaluation for NWS fit and proceeds towards more nuanced segment- or

[1] IESO IRRP Screening Framework p.2

[2] Integrated Resource Planning Framework for Enbridge Gas, 2021 p.9.

project-level need evaluation if this is required. In doing so, the framework can efficiently eliminate the parts of the work program where NWS are clearly not functionally or technically applicable and dedicate more time to the areas where opportunities are more likely.

Consistent Criteria, but Flexible Thresholds: we believe that Elexicon's SMEs would be best served by an NWS pre-screening framework that embedded some flexibility of specific numerical thresholds or categorical definitions – to enable more precise consideration or evolution over time as needs and/or analytical capabilities change. As stated in preceding sections, we also believe there to be good grounds for a single utility-specific custom criterion.

Focus on Primary Need Dimensions: while NWS deployments can conceivably provide a degree of incremental value in a wide variety of utility project settings, we believe it to be both prudent and consistent with the OEB's guidance to constrain our search for NWS fit to only the opportunities where the primary need driver can be materially addressed through an NWS solution. This focus need not deny opportunities for additional pilot or customer-specific projects where NWS deployment can be explored as a secondary or tertiary value driver. However, these do not need to interfere with the overall efficiency of the distribution system planning process.

Substantive Pre-BCA Triage: Provided that the pre-screening framework contains tests that can meaningfully triage the projects based on substantive features that explore NWS fit from locational, economic, operational, or other perspective(s), reducing the number of projects that proceed to the detailed BCA is an efficient and desirable outcome.

4. Insights from Scan of Other Jurisdictions and Distributor SME Interviews

This chapter starts from an overview of the key features of existing NWS pre-screening frameworks in place across multiple U.S. jurisdictions. We chose to forgo providing detailed summaries of each screening framework in favour of an approach that highlights the commonalities and divergences within the screening criteria themselves. However, we provide a complete summary table of all the frameworks in Appendix A. After completing our cross-jurisdictional scan and before commencing the buildout of our recommended pre-screening framework in earnest, we returned to Ontario to summarize the insights of our interviews with the members' Planning, Asset Management, and Regulatory staff. In this manner, our recommendations will reflect a three-dimensional review of:

- Ontario's NWS regulatory policy and process foundations
- Examples of NWS pre-screening approaches from other jurisdictions and
- CLD member-specific operating and technical circumstances.

This multi-dimensional perspective positioned us to develop an evidence-based framework that meets our stated objectives.

4.1. Overview of the Jurisdictions Considered

Non-wires solutions are increasingly being considered in distribution planning across North America and beyond, with some regulators requiring structured NWS evaluation and others relying on more informal pilots and ad hoc assessments. For this review, CRA focused on jurisdictions with formal NWS screening criteria embedded in distribution system planning, including New York (REV and the Joint Utilities DSP process), California's Distribution Investment Deferral Framework, frameworks used by National Grid and Eversource in Massachusetts and Rhode Island, and to a lesser extent – structured approaches in use Vermont, New Hampshire, and Hawaii. These jurisdictions (New York, Ontario, and Rhode Island) use explicit rules such as cost thresholds, size limits, and lead-time requirements to decide when NWS must be evaluated alongside traditional investments, making their practices particularly relevant to Ontario's context. By contrast, many other regions are pursuing one-off NWS pilots or commercial projects that, while useful for testing feasibility, do not provide durable or replicable screening methods. As a result, we excluded standalone pilots from our scope and instead drew on the more systematic frameworks noted above to inform a consistent screening approach for Ontario distributors, while recognizing that this list is not exhaustive.

4.2. Key Insights from the Jurisdictional Review

While we have encountered a degree of local variability across the jurisdictions we examined, we have also seen a convergence across several key issue areas that utilities and regulators employ as the foundation of NWS screening. While the higher-order criteria definitions are largely intuitive, we note that there is considerable variability when it comes to specific thresholds that different jurisdictions define alongside the decision criteria. The following passages summarize the criteria we encountered most frequently and outline (as applicable) the range of specific definitions and thresholds that further define each criterion.

4.2.1. Common Criterion 1: System Needs Eligibility

What is Deemed Eligible

Virtually every screening framework we reviewed begins with a list of "grid needs" / NWS use cases that planners consider applicable. Table 1 summarizes the common needs deemed eligible across the jurisdictions reviewed. Not surprisingly, the most common use case centers around Load Relief for capacity-constrained stations or feeder assets. This involves reducing electricity demand downstream of an asset that is designed to withstand a lower level of loading than what it may be forced to experience at the times of peak consumption due to organic load growth or new large customer additions.

Table 1: Common System Needs Deemed Eligible for NWS

	California	New York	Vermont	Hawaiian Electric	Eversource	Avangrid (NY, ME, CT)
Capacity Constraint Relief	x	x	x	x	x	x
Voltage Support / Power Quality	x	x			x	x
Reliability - Contingency Support	x		x			
Reliability - Radial Load Resilience				x		
Reliability - Other		x			x	x
New Connections Enablement		x			x	x
Renewables/DER Integration					x	

Note: National Grid (RI) & Liberty NH do not report screening criteria based on need type

Capacity Constraint Relief is the most common NWS use case among the jurisdiction surveyed and appears first in every framework we reviewed, with both front-of-the-meter and behind-the-meter resources used to relieve thermal overloads during peak demand, either individually or in combination. The second most common is Voltage Support and Power Quality, where NWS technologies supply or absorb reactive power or reduce local load to address voltage drop or quality issues; this use case is explicitly recognized in California, New York, Massachusetts, and Connecticut. The third major category is Reliability, which we further broke down into Contingency Support (using NWS to manage temporary overloads during planned work or emergencies, if equipment rating violations only occur under contingency scenarios) and Radial Load Resilience (using distributed generation and/or storage in microgrid-type configurations to keep radial load pockets energized during outages, often for wildfire mitigation in places such as California). Finally, New York is the only jurisdiction in our sample that explicitly identifies a fourth, New Connections Enablement use case for NWS consideration, where flexible connections or procured NWS capacity allow new customers to connect without triggering immediate upstream upgrades.

What is Deemed Ineligible

While not all screening frameworks that we reviewed explicitly list the use cases that they deem ill-suited for NWS deferral, the following is the list from jurisdictions that provide this guidance:

- Asset Condition Needs / Damaged Equipment
- Non-Capacity-Related Reliability
- Equipment Relocation or Undergrounding
- Fault Duty and Grounding
- Rectification of Safety Issues
- System Protection Projects
- Short Circuit Limitations Rectification
- Emergency Service Restoration
- New Customer Connections
- Grid Hardening for Wildfire, Flooding or Major Storm Mitigation.

Table 2 illustrates which jurisdictions deem which use cases ineligible.

Table 2: Common System Needs Deemed Ineligible for NWS

	California	New York	Hawaiian Electric	Eversource	National Grid (RI)	Avangrid (NY, ME, CT)
Asset Condition Needs / Damaged Equipment	x	x	x	x	x	
Non-Capacity-Related Reliability	x	x				
Equipment Relocation or Undergrounding			x			
Fault Duty and Grounding						
Rectification of Safety Issues				x		
System Protection Projects						x

	California	New York	Hawaiian Electric	Eversource	National Grid (RI)	Avangrid (NY, ME, CT)
Short Circuit Limitations Rectification						x
Emergency Service Restoration	x		x	x		
New Customer Connections			x			
Regulatory Requirement		x				

The above list is predominantly comprised of system needs that involve establishing or maintaining physical integrity of the assets that support the process of electricity distribution through a combination of their material, mechanical or digital properties. By contrast, a common outcome of an NWS being activated is the reduction of electrical / thermal loading on upstream assets with the aim of bringing them in line with their rated capabilities.

While we believe that this dichotomy is relatively intuitive, CRA acknowledges that there may be a theoretical "gray area" when it comes to the impact that load reduction can have to help manage the risk of in-service failure of assets like power transformers and distribution transformers. Although Load History[3] is a common asset condition parameter for these asset classes, it is typically a relatively minor contributing factor relative to other demographic or condition-based parameters. Moreover, Eversource CT's NWS screening framework specifically eliminates from further consideration all stations with a transformer health index that indicates significant internal degradation.[4] In making this exclusion, Eversource references an EPRI technical paper 3002019254[5] that discusses the dynamics of winding insulation paper degradation, including recommendations for thresholds beyond which the units are recommended for replacement.[6] As such, the combination of our research insights and our broader industry experience give us no reasons to view NWS as a suitable means of prolonging the life of equipment slated for replacement due to its measured asset condition.

3 As an asset condition parameter, Load History is typically defined as percentage of time that the asset has operated at or above 90% of its rated capacity.

4 Eversource, "Non-Wires Alternative Framework: Version 2.0" p.3.

5 https://www.epri.com/research/programs/109331/results/3002019254

6 CRA notes that we have not accessed or reviewed the EPRI paper referenced but rather relied on the references provided in the Ever source documents.

4.2.2. Other Common Criteria Used:

Need Velocity / Lead Time Requirements

Many frameworks emphasize the importance of accounting for lead time available to procure NWS before the need date. While some jurisdictions allow utility-owned front-of-the-meter (FOTM) distributed generation (DG) or battery energy storage systems (BESS), the default expectation is that competitive third-party procurement of NWS takes place. The third-party procurement process of NWS services is commonly acknowledged to be complex and uncertain. As a result, many jurisdictions only screen in the projects with sufficient lead time before the underlying need is expected to materialize. Jurisdictions typically require about 2-5 years of notice to scope, procure and implement NWS, and still retain enough time to revert to a conventional solution if procurement fails. Examples include California (generally 3-5 years, with some 18-month cases where relationships already exist), New York (around 18-24 months for small projects, 3-5 years for larger ones), Vermont (with the broadest range of 2-10 years) and Massachusetts (from 30 months to 3 years). The IESO IRRP and Enbridge IRP frameworks are broadly consistent, with minimum timelines of roughly 2 and 3 years.

Need Scale/Size

Need scale refers to the magnitude of the capacity gap. In practice, NWS are mostly used for smaller, geotargeted needs such as feeder overloads or station contingency support. Utilities and regulators see NWS as less suitable for large, firm capacity shortfalls where volume, duration and uptime requirements are harder to meet reliably with DER portfolios. Several jurisdictions therefore apply upper limits. Planners in New York, Vermont and National Grid (Massachusetts) generally limit NWS to needs of about 20–25 percent of area peak load. Hawaiian Electric classifies needs up to 5 MW and four hours as favorable and 5–10 MW or longer duration as moderate or uncertain. Eversource limits DER output on a feeder to 33 percent of minimum load and caps achievable CVR benefit at 1.8 percent based on its own experience.[7] In Ontario, the IESO framework lists CDM as viable only for up to 2 percent peak reduction. These examples show both the value of size thresholds and the legitimacy of utility-specific limits grounded in operating experience.

Need Duration

Need duration captures how many hours per day a need underlying the investment is expected to persist. Across jurisdictions, NWS are framed as deferral tools best suited for short-duration peak events, such as seasonal peak relief or short violations of feeder ratings. California's DIDF explicitly highlights short, predictable peaks as ideal NWS candidates. PG&E's DDOR distinguishes between baseload capacity (24 hours per day for a period) and peaking capacity (~4 hours per day on a subset of days) and modifies these based on seasonal conditions.[8]

An independent monitor assessing PG&E's NWS procurement process found that bids to meet baseload needs often exceeded the cost of traditional upgrades, concluding that NWS are more cost-effective for needs with limited duration and frequency, while wires investments become more economic as duration and frequency grow. This is consistent with the technical limits of BESS and typical DSM programs, which are generally sized for hours of relief rather than multi-day or seasonal capacity, and with the reality that longer-duration NWS often require non-renewable generation that erodes the relative advantage over wires.

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7 Eversource, Non-Wires Alternative Framework, Version 2.0

8 Pacific Gas and Electric, 2023, "PG&E's Distribution Deferral Opportunity Report." p. 23

Cost Effectiveness

When deferral is contemplated, a key question is how much cheaper the NWS path must be to justify additional complexity, uncertainty and third-party dependence. To this end, some frameworks include explicit thresholds as proxies of expected cost effectiveness levels. For example, National Grid in Rhode Island caps NWS costs at 60 percent of conventional alternatives. Meanwhile, a recent PG&E community pilot uses an 85 percent threshold, above which conventional solutions are automatically considered. [9] There may also be practical reasons to ensure that a substantial value margin is in place. In our view, NWS services procurement is currently outside of traditional distributor core competencies, while conventional assets have long useful lives, and NWS deployments increase reliance on third party services in what is still a nascent and volatile industry. On balance, having reviewed these examples, we concluded that if a numerical cost effectiveness threshold is to be used, it should not be unreasonably low, applied only where costs of NWS alternatives and conventional solutions are both well known, and treated as an input to, not a substitute for a later BCA.

Market Readiness

Market readiness is term we borrowed from PG&E's framework that reflects its assessment of likelihood that the NWS marketplace can supply the needed NWS capacity of a particular type or in a particular area. During our interviews, distributor SMEs described using IESO data, surveys, customer outreach and a variety of early analytical efforts to gauge potential but also noted that data gaps as to the market penetration of DER devices or customers' willingness to provide DR services persists. While we expect that AMI 2.0 that all distributors we interviewed can help close this gap over time, all distributors acknowledged that this is a longer-term proposition. Against this setting PG&E's framework provides a simpler and potentially compelling proxy for market readiness – by categorizing the investment needs according to their expected duration per event, MW displacement requirement, operational requirements and the number of overlapping needs, and then using these data points as *relative* triage tools to identify the needs that are more or less likely to be accommodated by the market place – rather than a hard screen. We note that this approach is possible for PG&E because of its substantial NWS procurement experience. Given Ontario's more limited track record, it may be reasonable to initially to screen out needs that would require technically complex or highly integrated NWS portfolios and to focus early efforts on more accessible use cases.

Jurisdictional Scan Conclusions

Taken together, the criteria discussed above converge on a practical view of NWS. Across jurisdictions, the most useful lessons for our pre-screening design are that NWS are primarily used to offset equipment rating limits rather than extend the life of assets marked for condition-based replacement; that approximately three years of lead time is a practical lower bound for meaningful NWS procurement, that even experienced utilities struggle with third-party market readiness assessment and thus use simplified proxy metrics, and that numerical thresholds are generally expressed in relative terms rather than absolute values. As we discussed in Chapter 4, we incorporated these learnings into the framework we recommended to Elexicon.

4.3. Distributors Interviews Summary

To develop viable screening criteria for implementation in Ontario, CRA recognized the need to go beyond regulatory policy deep dives and jurisdictional scans. We felt that another critical layer of inputs into our pre-screening framework was a deeper understanding of Elexicon's and

[9] PG&E 2023 Distribution Deferral Opportunity Report p.35

its closest peers' technical capabilities, current degree of them integrating NWS-related analysis into the capital planning processes, and strategic priorities related to grid edge investments. To achieve this, CRA conducted interviews with Elexicon's Hydro One's Toronto Hydro's and Hydro Ottawa's technical and regulatory teams and reviewed their most recent Distribution System Plan (DSP) submissions. This approach sought to ensure that the pre-screening criteria we recommend were appropriately calibrated to operational realities and capabilities reflecting current maturity levels among larger Ontario utilities.

We chose this approach to concentrate on the major central themes that resonate with multiple members, rather than highlighting individual successes, challenges, or utility-specific positions, attitudes, or plans. Our discussions centered around the following topics:

- Current technological capabilities and staffing supporting the NWS value chain,
- Range of existing NWS deployments in use today, and key insights gained,
- The extent to which NWS analysis is already integrated into capital planning, and
- Utility positions on investments or system needs that are most and least suitable to NWS.

A common thread among our discussions was the universal recognition of the value offered by NWS. This has manifested in past projects of various magnitudes initiated or contemplated long before the formal introduction of NWS guidelines. While the focus for the interviewees remains on reliability, affordability, and service quality outcomes delivered through prudent investments in core assets, all are cognizant of the opportunity presented by NWS. Most are, however, aware of both data and analytical or control capabilities that are still not in place, which collectively create both logistical and cost uncertainty for NWS implementation.

4.3.1. Foundational Capabilities for NWS Analysis and Support

When we asked the NWS members about the tools and processes that their staff saw as being at the core of a functional NWS program, the responses coalesced around five sets of functional capacities we briefly describe below:

- An established *Load Growth & Flexibility Research* function – a combination of analytical models and customer research functions (e.g. Key Accounts engagements with new and existing large customers, residential customer surveys, etc.) to gauge the size, location, and potential timing of new load and/or track customer-side NWS opportunities. This may also include more advanced technological functions like "bellwether" AMI meters equipped with additional data gathering functionalities, load disaggregation models capable of predicting the types of equipment located behind customer meters based on consumption patterns and/or voltage waveform data, and others.
- Regularly updated and increasingly granular *Bottom-Up Load Forecasting* models, equipped to produce and regularly update quantitative load forecasts of sufficient locational and temporal granularity to enable consideration of geotargeted NWS solutions. Ideally, this would entail bottom-up load forecasting models capable of aggregating utility-wide forecasts from a station (or preferably more granular – bus or feeder) level up. While *locational* load forecasting granularity is desirable to identify specific load pockets where geotargeted solutions would be of most value, temporal forecasting granularity is desirable to outline the approximate number of months, days, and hours per year when an NWS solution's services may be required. A key facet of an advanced bottom-up load forecasting model highlighted by members would involve regular reconciliation with the IESO's forecasts, plans and assumptions regarding CDM, programs, regional planning analysis, and other initiatives impacting a given local area.
- A robust and efficient NWS *Procurement and Settlement Function* – a combination of solutions and individuals equipped to conduct or coordinate the Request for Offers (RFO)

proceedings or other forms of price and supply discovery, execute the contracts and enable timely payment to participating service providers. CRA understands that these services can be outsourced to third-party aggregators or other electricity market entities. However, doing so requires the presence of rate funding and availability of internal personnel to coordinate with, monitor, audit (as needed), and facilitate regular financial settlements with participants parties. Moreover, even if much of the logistics are carried out by third-party agents, internal capacity is required to oversee the programs and ensure that the marketplace signals align with the utility's expectations.

- *Dispatch Order Capabilities* – IT/OT tools, operating processes, and dedicated staff time to integrate the recent operating statistics and weather forecasts into actionable dispatch orders to owned or contacted NWS fleet and then convey these orders at the appropriate time, while notifying the field crews and contractors working on the system and verifying order compliance. As we discuss below, the complexity of the technology tools to execute this function can vary on many factors, including the type of system need and the overall number and dispersion of NWS-supported deployments across the system. However, there is a broad expectation among the utilities that dispatch tools and processes form a portion of baseline NWS capabilities.
- A variety of *Telemetry* tools for data acquisition and processing is the final portion of the baseline stack of NWS capabilities that frequently arose in discussions with technical staff members. While real-time monitoring and response to grid congestion, outages or voltage drop scenarios is seen as a general compass direction, members agree that there are multiple prudent (and cost-consequential) interim steps before widespread real-time monitoring becomes a necessity. In the meantime, member utilities look forward to expanding the types and volumes or frequency of data available from substation equipment and/or key feeder locations.

Given the insights of our conversations with Elexicon and its peers, CRA concluded that for the purposes of our mandate, a flexible, yet consistent framework that allows utilities to apply the same screening criteria based on their unique capabilities that can evolve over time is optimal, service territory characteristics, corporate risk appetite, and strategic priorities.

5. Screening Framework Development

Having completed three sets of research-based and/or analytical tasks that explored the local policy requirements, cross-jurisdictional precedents, and the operational issues most relevant to Elexicon and its peers, we developed our own recommended framework. As we discussed in Chapter 2, we believe that the OEB's *NWS Guidelines* contemplate four broad categories of system needs and programs or projects designed to address them as they relate to NWS:

- *Programs & Projects that the OEB Deems to be Structurally Unsuitable for NWS*: this concerns all General Plant investments, which the NWS Guidelines clearly exclude from any further consideration.
- *Programs and Projects that Distributors Determine to be Structurally Unsuitable for NWS:* consistent with the NWS Guidelines' expectation that "some system needs may be clearly unsuitable for NWS" distributors can eliminate additional system needs and projects or programs that support them from further NWS screening.
- *Programs and Projects Considered for NWS Opportunities:* these are the programs and projects where NWS could be a potential solution, but which undergo more focused pre-screening for economic, operational and/or strategic fit ahead of proceeding to the BCA analysis.
- *Programs and Projects Analyzed for NWS Opportunities*: this is the final category of projects that have passed the entire pre-screening framework and are being analyzed for economic fit through the BCA process.

Our recommended pre-screening framework described below addresses the middle two categories from this list. Part 1 of the framework seeks to identify the system needs and the projects and programs designed to address them where NWS aren't feasible due to the mismatch between the types of technical services they are equipped to provide and the types of technical intervention required to address the system needs. Part 2 of the framework entails a more detailed assessment of system needs, projects and programs for which a preliminary technical fit with an NWS has been established. At this juncture, the pre-screening framework explores more specific dimensions of fit between a need and an NWS solution, further triaging the list of the opportunities that may warrant BCA analysis. While Part 1 of the framework focuses on technical aspects, Part 2 seeks to explore the economic, strategic, and operational compatibility between the remaining system needs and their feasibility of being addressed through NWS.

5.1. Phase 1: Technical Fit Screening

Our Technical Fit Screen seeks to efficiently screen out the system needs and traditional investments designed to address them where NWS solutions cannot be expected to play a significant role due to the inherent lack of technical or functional capability to provide the requisite types of output on the part of NWS. When contemplating the breadth of distributors' typical investment categories, we find that the Technical Fit Screen lands itself well to administration at the Program level. We understand that Programs are a common classification nomenclature across Elexicon's and many other distributors' investment plans, which group thematically similar system needs proposed to be addressed by functionally similar types of new asset deployments or interventions upon existing assets. Just like programs themselves are designed to group similar types of investment needs and solutions, we see it as reasonable to explore whether NWS are a suitable alternative for technically and functionally similar groups of investments on the program level as well.

5.1.1. Functional Assessment

To build the first part of our Technical Fit screen, CRA compiled a generic list of common investment programs and major asset classes and defined the core functional outcomes they are expected to deliver. For comprehensive programs that contemplate simultaneous interventions into multiple asset classes (e.g. Stations Upgrades, Overhead or Underground Renewal), we broke them into major asset classes to enable analysis at a more granular level. For each program or asset class, we then drafted a short description of the essential function or outcome that must be achieved for the investment to meet its primary purpose, and separated them into four functional categories:

- *New Service*: Physical enablement of electricity service to new customers.
- *Lifecycle Management*: Removal of threat to service continuity or safety due to physical damage or structural degradation of internal or external components.
- *Capacity Management*: Addressing the insufficient physical properties to accommodate downstream demand without sacrificing asset lifecycle.
- *Functionality Upgrade*: Enhancing operationally deficient performance features of the existing system that affect operational efficiency or outcomes for end users.

While these categories closely match the OEB's System Access, System Renewal and System Service categories used in utility DSP, our categorization separates System Service projects into two main functional categories, only one of which (Capacity Management), can be potentially addressed with NWS. Having categorized our generic list of investments and intervention modes into functionally similar categories we then produced a plain language definition of a core functional outcome that a given investment seeks to enable (as shown in Table 3: Technical Screen ResultsThese definitions of the typical investments' core functional purposes formed the first portion of our technical test – enabling CRA to assess whether typical NWS deployments (e.g. Demand Response, Distributed Generation, Managed EV Charging and Front-of- and Behind-the-Meter Storage) can be expected to perform the functions that distributors expect when undertaking investments.

While simple in design, the approach of reviewing opportunities for innovation in terms of their fit with core functions expected of conventional products draws on academic managerial innovation literature. The most notable example is the "Jobs to Be Done" theory of product innovation developed by Clayton M. Christensen and his Harvard Business School colleagues in 2016.[10] Our abridged adaptation of this theory also allows us to see whether and how the innovative solutions could be "hired" to perform the functions normally reserved for traditional utility equipment. Table 3 integrates the results of our functional assessment, together with the outcomes of our Engineering Assessment, which we describe next.

5.1.2. Engineering Assessment

To anchor our functional review in engineering science, we drew on Kinectrics' 2010 *Asset Depreciation Study for the Ontario Energy Board*, which remains a key technical reference for the Ontario distribution sector on a variety of issues. [11] In addition to providing technical guidance on the ranges of reasonable depreciations for different assets, the study also rates how strongly different physical degradation factors affect them. Among these degradation

[10] Christensen, Hall, Dillon and Duncan. "Know Your Customers' Jobs to Be Done." Harvard Business Review 94, no.9 (September 2016): 54-62

[11] Kinectrics, Asset Depreciation Study for the Ontario Energy Board, July 8, 2010

factors are Mechanical Stress and Electrical Loading, which affect a broad variety of assets, and in our assessment, are useful to construct a simple a simple assessment framework that approaches a binary methodology, similar to one used by the IESO. These two types of technical forces are particularly useful because NWS primarily act by relieving electrical loading (or compensating for the lack thereof during outages) on upstream energized assets, while having no means of relieving the mechanical stress that many types of assets experience as they age. With this distinction in mind, we populated our generic list of typical investments (where relevant) with Kinectrics' assessments of the degree to which Mechanical Stress and/or Electrical Loading affect their degradation, as shown in Table 3.

When approaching the investment categories where Kinectrics rated Electrical Loading as "Low" or "No Impact", we screened those needs out for NWS, since reducing load is unlikely to change the underlying failure risk. Where Electrical Loading was assessed to be "Medium", we screened in those investments as well – unless they were not also assessed to be subjected to Medium or higher Mechanical Stress. Our reason in making this distinction was that where both types of forces were present in equal measure, it was insufficient for NWS to address only one of them to be considered a viable technical alternative. For composite investment activities involving multiple asset classes, we assessed them separately to provide a more nuanced reference for future implementations of our framework. Where neither mechanical nor electrical stress was a major driver (such as with new asset deployments or functionality upgrades), we relied on the results of the Functional Assessment alone.

Integrating our Engineering Assessment results with our earlier Functional Assessment definitions, we classified our generic investments list into one of the following three groups as a reference for our framework's future applications to Elexicon's (or other utilities') investment plans:

- *Screened out due to lack of technical properties fit* (where both the Engineering and the Functional assessment results indicated that NWS cannot address the core underlying need),
- *Screened out due to no impact on functional properties from NWS* (where the Technical Assessment results were not available or were inconclusive, but the Functional Assessment results showed the lack of fit between the core investment need and NWS capabilities), and
- *Continue assessment* (where there was potential NWS impact based on either or both assessments, or the results were inconclusive).

In addition to these three categories that applied to much of our investments list, we also recommend excluding from further consideration investment types that are themselves examples of NWS. As Table 3 indicates, this process resulted in us recommending that 31 of the 38 investment types we examined could be excluded from further NWS screening based on the lack of technical fit with NWS capabilities.

The remaining seven investment types from our generic list were deemed to move to the subsequent stages of our framework. They were: (i) New Subdivision Load Growth Enablement, (ii) Customer Connection Upgrades, (iii) Overhead Conductor Capacity Upgrades, (iv) Distribution Transformer Capacity Upgrades, (v) Underground Cable Capacity Upgrades, (vi) Station Equipment Capacity Upgrade, and (vii) Station to Station Load Transfer.

In practice, the implication of our analysis is that most programs driven by asset replacement (System Renewal) and most new customer connection programs (System Access) are structurally unsuitable for NWS. The remaining candidates are comprised mainly of capacity upgrades and related investments. While this conclusion is highly intuitive, we believe there is value in applying a simple and objective framework to confirm this expectation – as we sought to do here.

Table 3: Technical Screen Results

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
1. New Service Needs & Programs				
New Customer Connection	n/a	n/a	Physical integration of new customer loads with the distribution system for continued drawing of power.	**Screened Out** - no expected impact on functional properties from NWS.
New Subdivision Load Growth Enablement: Feeder Construction	n/a	n/a	Proactive extension of dedicated physical line assets into a vacant area with expectation of eventual interconnection of new loads.	**Screened Out** - no expected impact on functional properties from NWS.
New Subdivision Load Growth Enablement: Station Construction	n/a	n/a	Construction of dedicated station assets to enable future interconnection of new subdivision loads in presently vacant areas.	**Continue Assessment** - potential NWS Impact or Inconclusive
Customer Generation Integration (*includes protection & anti-islanding installation*)	n/a	n/a	Enablement of safe & efficient incorporation of distribution-connected electricity output sources into the distribution grid.	**Screened Out** - no expected impact on functional properties from NWS.
3rd Party Attachments / Joint Use Installation	n/a	n/a	Installation or modification of third party-owned telecommunications equipment on physical overhead structures owned by the utility.	**Screened Out** - no expected impact on functional properties from NWS.
2. Lifecycle Management Needs & Programs				
Metering - Hardware Lifecycle Management	n/a	n/a	Digital measurement and recording of individual customers' (or the utility's at station facilities) power consumption, voltage, or current readings.	**Screened Out** - no expected impact on functional properties from NWS.
Metering – AMI Field Telecom Lifecycle Management	n/a	n/a	Deployment of an RF telecommunications mesh network or a cellular modem-enabled spot signal to transfer metering data from local customer to the utility's Head End System.	**Screened Out** - no expected impact on functional properties from NWS.

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
Facilities Relocation	n/a	n/a	Physical removal and reinstallation of existing overhead or underground facilities driven by third party requests.	**Screened Out** - no expected impact on functional properties from NWS.
Poles and Pole-Top Equipment Lifecycle Management	H	L [12]	Mechanical support and insulation of energized line components at vertical and horizontal appropriate setbacks for public safety and efficient operations.	**Screened Out** – lack of technical properties fit.
Overhead Conductor Lifecycle Management	M	L	Efficient conveyance of electricity between sequential points of transformation towards the point of end use.	**Screened Out** - lack of technical properties fit.
Line Switch and Recloser Lifecycle Management	L	L	Automated or manually enabled connectivity conveyance or severance - as required by normal or contingency operational needs.	**Screened Out** - lack of technical properties fit.
Distribution Transformer Lifecycle Management	L	M	Safe and efficient step voltage change to enable end-user consumption of electricity at the desired voltage.	**Screened Out** - no expected impact on functional properties from NWS.
Underground Cable Lifecycle Management	M [13]	M	Conveyance of electricity below grade between the points of transformation and the point of customer use.	**Screened Out** - no expected impact on functional properties from NWS.
Underground Conduit Lifecycle Management	H	NI	Protection, via an additional physical barrier, of current-carrying cables from underground environmental elements that can accelerate its degradation. Improved access for planned or emergency maintenance.	**Screened Out** - lack of technical properties fit.

[12] For this category, there was variation amongst the electrical loading degradation score of the equipment subcategories (e.g. steel vs. concrete poles). The majority had a low electrical loading score and a smaller proportion had a medium score.

[13] For this category, there was variation amongst the mechanical stress degradation score of the equipment subcategories (e.g. underground cable types). The majority had a medium score and a smaller proportion had a low score.

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
Underground Cable Chamber Lifecycle Management	M	NI	Provision of safe access to multiple underground cable joints and termination points to enable inspection, maintenance, splicing or other lifecycle management operations.	**Screened Out** - lack of technical properties fit.
Transformer Vault Lifecycle Management	M	NI	Provision of safe access to and environmental separation of distribution transformers located below-grade.	**Screened Out** - lack of technical properties fit.
Power Transformer Lifecycle Management	NI	M	Safe and efficient voltage step reduction, to enable downstream power transfer towards end user load.	**Screened Out** - no expected impact on functional properties from NWS.
Station Circuit Breaker Lifecycle Management	M	M	Interruption of current and isolation of station equipment during faults or switching operations - to ensure safety and protect station equipment.	**Screened Out** - lack of technical properties fit.
Station Relays Lifecycle Management	NI	NI	Ongoing monitoring of system electrical quantities (current, voltage, frequency), and initiation of circuit breaker tripping sequence upon detecting an electrical abnormality of fault condition.	**Screened Out** - lack of technical properties fit.
Station Recloser Lifecycle Management	M	L	Interruption of current to disconnect a specific feeder at a point of station egress - upon detecting a fault or another voltage abnormality on the feeder, and subsequent attempts to reconnect the feeder should the fault be cleared.	**Screened Out** - lack of technical properties fit.
Station Switchgear Lifecycle Management	L	L	Structural support and electrical connectivity of switching, sensing and protection equipment to enable manual or automated station switching processes as required for maintenance or outage response operations.	**Screened Out** - lack of technical properties fit.

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
Station Current and Potential Transformers	NI	L	Proportional stepping down of higher current (CT) and voltage (PT) to enable measurement for metering and low-voltage protection enablement.	**Screened Out** - lack of technical properties fit.
Station Civil Infrastructure Lifecycle Management	L	NI	Mechanical support, affixing in place, and separation (where needed) of energy-conveying and protection equipment, and/or prevention of safety	**Screened Out** - lack of technical properties fit.
Feeder Conversion - Overhead to Underground	n/a	n/a	Reduced environmental exposure to mitigate outage threats, simplify future maintenance access, and improve appearance.	**Screened Out** - no expected impact on functional properties from NWS.
Feeder Sectionalization	n/a	n/a	Physical separation of existing feeders into components that host an approximately equal number of customers and are separated by load break switches or fuses to reduce impact of outages.	**Screened Out** - no expected impact on functional properties from NWS.
Feeder Voltage Conversion	n/a	n/a	Replacement of legacy design low voltage pole and conductor equipment with higher-rated and modern equipment to reduce losses, standardize equipment and reduce system capital intensity.	**Screened Out** - no expected impact on functional properties from NWS.
3. Capacity Management Needs & Programs				
Customer Connection Upgrades	n/a	n/a	Upsizing existing interconnection and/or transformation facilities to accommodate greater needs.	**Continue Assessment** - potential NWS Impact or Inconclusive
Overhead Conductor Capacity Upgrade	n/a	n/a	Increase of equipment's current carrying capability through replacement with a larger / higher-rated unit - potentially independently of demographics or condition.	**Continue Assessment** - potential NWS Impact or Inconclusive

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
Distribution Transformer Capacity Upgrade	n/a	n/a	Increase of equipment's current carrying capability through replacement with a unit rated for higher throughput).	**Continue Assessment** - potential NWS Impact or Inconclusive
Underground Cable Capacity Upgrade	n/a	n/a	Increase of equipment's current carrying capability through replacement with a unit rated for higher throughput.	**Continue Assessment** - potential NWS Impact or Inconclusive
Station Equipment Capacity Upgrade (*Power Transformer, Circuit Breakers, Switchgear*).	n/a	n/a	Increase of equipment's current carrying capability through replacement with a unit rated for higher throughput, or addition of a new unit to maintain prescribed loading levels (e.g. N-1 standard).	**Continue Assessment** - potential NWS Impact or Inconclusive
Underground Civil Infrastructure Spatial Expansion	n/a	n/a	Physical enlargement of the existing civil facilities dimension to enable housing of larger sizes or a greater count of equipment, or provision of additional space to enable safer work conditions.	**Screened Out** - no expected impact on functional properties from NWS.
Load Transfer - Bus-to-Bus / Phase to Phase	n/a	n/a	Physical relocation of feeder breaker positions between multiple station buses (where available) to optimize station capacity and manage equipment loading in accordance with reliability standards.	**Screened Out** - these investments are themselves an example of an NWS
Load Transfers - Station-to-Station	n/a	n/a	Physical construction of new or upgrade of existing feeder facilities to enable connection of new or increased loads to geographically distant stations when sufficient capacity is lacking at more proximate stations.	**Continue Assessment -** potential NWS Impact or Inconclusive *(may be an NWS, or may require new feeder construction, or existing feeder capacity & functional upgrades*).
4. Functionality Upgrade				
Capacitor Banks and Voltage Regulators Placement,	L	M	Target voltage performance enablement on long feeders, or feeders connecting certain types of customer equipment (e.g. intermittent	**Screened Out** - these investments are themselves an example of an NWS.

Investment Types	Technical: Degradation Factor Impact Assessment		Functional: Core Outcome to be Enabled through Intervention	Implications for NWS Pre-Screening of Similar Categories
Description	**MC**	**EL**	**Description**	**Description**
Relocation or Reprogramming			renewable generation or large inductive loads).	
SCADA System Upkeep and Expansion	n/a	n/a	Enablement of digital connectivity between the distributor's control centre and equipment located in stations or along feeders to collect operating information and direct remotely operable equipment.	**Screened Out** - no expected impact on functional properties from NWS.
Station / Pole RTU Equipment Upgrades	NI	NI	Installation or modification of existing telecommunication portals within substations to enable interconnection of additional and/or more sophisticated monitoring or measurement equipment and rapid transfer of readings to the control center.	**Screened Out** - no expected impact on functional properties from NWS.[14]
Line and Sensor Lifecycle Management	n/a	n/a	Monitoring of voltage, current, fault indicator, or station asset health and operating parameters to enable tactical or strategic decision-making by utility management.	**Screened Out** - no expected impact on functional properties from NWS.

While our list of investments assessed above is hypothetical, we developed it as a reference – to be used by Elexicon or other distributors when assessing the technical fit between their real-life investment needs / conventional programs addressing them and NWS opportunities.

This concludes Phase 1 of our recommended pre-screening framework. We now proceed towards our recommendations for the Phase 2 assessments to be applied to the remaining programs or projects after the Technical Assessment is completed.

[14] It is worth noting, however, that this type of technology can help enable various manifestations of NWS by supporting remote monitoring.

5.2. Operational, Economic, and Strategic Screening

Having discussed our Technical Fit Screen, we now move to the more nuanced portion of our recommended NWS screening approach, designed to consider the fit with NWS solutions for projects where a high-level technical fit with NWS technical value drivers has been confirmed. At this juncture, we propose that the level of assessment granularity be lowered to a project level (where this granularity exists) – i.e. individual scopes that made up the programs that were screened in during our Technical Fit test. Where the number of individual projects would make project-level assessment impractical, CRA recommends organizing the projects in tranches based on two criteria: first year of anticipated demand, and financial magnitude relative to the OEB's $2-million BCA threshold.

Table 4 illustrates the order and provides a brief description of the screens comprising our second and final part of the NWS Pre-Screening Framework. As conceived, the second part of our NWS Pre-Screening Framework consists of seven screening fit tests, including an optional seventh utility-specific test that Elexicon can define based on its staff's discretion. CRA notes that four of our tests also include proposed numerical ranges, inviting planners to apply their discretion to reflect their expert knowledge in a more nuanced way. We discuss our reasoning for each individual test component below.

Table 4: Phase 2: Operational, Economic & Strategic Screening Criteria

Test Name	Test Description	Thresholds & Implications
Need Primacy Fit Test	Can a potential NWS deployment satisfy the primary driver of the project need in question?	Yes → Move to Next Screen No → (e.g. where another primary driver exists or NWS provides a secondary benefit only) Screen Out.
Need Velocity Fit Test	Does the utility have sufficient time to procure suitable NWS before the need in question materializes	**Threshold Value: 36-40 months** (utilities to select exact value). Yes → Move to Next Screen No → Screen Out
Event Frequency Fit Test	In the first year when the forecasted need materializes, how often is the identified system need expected to arise during peak demand seasons?	**Threshold Value: 30-50% of business days** (utilities to select exact value). Below Threshold → Move to Next Screen Above Threshold → Screen Out
Event Duration Fit Test	In the first year of the need materializing, how long is the average duration of each event forecasted to last?	**Threshold Value: 3.5 – 4 hours** Below Threshold → Move to Next Screen Above Threshold → Screen Out
Cost Responsibility Fit Test	Is a specific subset of customers (one or multiple, present or future) responsible for the need arising, and is expected to provide an appropriate amount of capital contribution as required by the DSC provisions?	Yes → Screen Out No → Move to Next Screen

Test Name	Test Description	Thresholds & Implications
Technical Pre-Requisite Fit Test	If met with an NWS, does the need require a contemporaneous enabling technology investment in the amount equal to the utility's OEB filing materiality threshold, which would not otherwise be made in the next 5-year period from the time of assessment?	Threshold Value: Utility-specific OEB Materiality Threshold.
Utility-Specific Custom Fit Test	An optional, utility-specific threshold question. For example: *"Is the ownership of FOTM DG or BESS equipment consistent with the utility's AM strategy as defined for the next five-year period?"*	Depending on the test parameters (if any).

5.2.1. Gate 0: OEB Mandated Thresholds

Plain language definition: are distributors focusing their efforts on projects with sufficient material cost deferral or avoidance upside to justify the effort?

Why we proposed it: the OEB mandates in its NWS Guidelines that distributors are required to document their consideration of NWS when making investment decisions with an expected capital cost of $2m or more, excluding general plant.

How we chose the threshold values: the OEB prescribed this value.

5.2.2. Test 1: Need Primacy Fit Test

Plain language definition: can an NWS address the main reason a project is being contemplated, or is the contribution of NWS only supporting / secondary in nature?

Why we proposed it: many projects featured in member utilities' DSPs feature two or three complementary need drivers. CRA believes that at this juncture of the formal NWS assessment process integration into Ontario's distribution planning, it is prudent to focus the new process on opportunities where it can provide the greatest degree of impact.

How we chose the threshold values: this test has no specific threshold values, though in the event where needs / projects are assessed to have two primary need drivers (e.g. End of Life Condition and capacity upgrade), we recommend that they be screened out if no commercial NWS solution can conceivably satisfy all the primary need drivers.

5.2.3. Test 2: Need Velocity Fit Test

Plain language definition: does the distributor have enough time to explore procuring the third-party and/or self-owned NWS resources and still have enough time to construct the conventional solution if the NWS option proves to be logistically or economically infeasible?

Why we proposed it: this is the most common test across the pre-screening frameworks that we reviewed, including the IESO's framework. It speaks directly to the logistical complexity of procuring NWS services and echoes the fact that the further out a given need is – the less certain it may be, and the more prudent it is to explore the NWS options.

How we chose the threshold values: a three-year timeframe is roughly equivalent to the lower average boundary of the minimal acceptable timeframes cited in the precedent framework that we reviewed. We added approximately 10% to create a range of 36-40 months to recognize that there are substantially higher recommended lead time thresholds among the precedent

frameworks we reviewed. We gave the utilities discretion to set the exact threshold in recognition of their current go to market / price discovery capabilities, and the latest information on supply chain lead times for conventional or NWS assets.

5.2.4. Test 3: Event Frequency Fit Test

Plain language definition: does the distributor expect the need for incremental support to be relatively infrequent, or a relatively common occurrence during the applicable demand period, and as such, is better addressed through a wires solution better equipped to handle consistently higher load factors?

Why we proposed it: our attention to the dichotomy between the "baseload" vs. "peak" incremental resource needs and the challenges in procuring the former in the context of both third-party services and utility-owned assets was drawn by the California example. While CRA felt that considerably more experience was required before a dedicated California-style "Market Maturity" screen could be developed, the event frequency test is our proposed attempt at an early surrogate. We also note that our original formulation of this screening test was focused explicitly on the time of year that the IESO defines as Summer (May 1 through October 31st). However, Elexicon correctly pointed out that some parts of its system are winter-peaking, and as such, we agreed to make this criterion more flexible – enabling planners to apply the appropriate definition of peak period to a given system need under consideration. This is an example of the more nuanced analysis that can take place once a large portion of total system needs have been screened out as being unfit for NWS options, as our framework seeks to do.

How we chose the threshold values: we felt that between a third and half of all the business days during the periods that the IESO defines as Summer or Winter (as applicable to a given system need) represented an adequate range for member utilities to select an appropriate value for. In our assessment, the proposed frequency threshold range[15] could be feasibly addressed by a utility-owned BESS solution from a technical perspective. However, the significant frequency (and the implied load factor magnitude) is approaching the levels where conventional solutions may be preferable.

5.2.5. Test 4: Event Duration Fit Test

Plain language definition: when they happen, will the events last a sufficiently short amount of time to expect that a Demand Response, dispatchable local generation, or a typical commercially available BESS solution can address it?

Why we proposed it: we have encountered statements suggesting that NWS are best suited for shorter-duration event needs in multiple frameworks that we have encountered.

How we chose the threshold values: a four-hour window is frequently mentioned as a typical event duration for which it is feasible to procure third-party NWS services. Similarly, four hours is within a typical output range of commercially available BESS systems. We provided utilities with a recommended discretionary 30-minute threshold range to reflect their own operating experience.

5.2.6. Test 5: Cost Responsibility Fit Test

Plain language definition: if a specific customer or a group of customers triggers the need for upgrades that could be accomplished by either NWS or conventional solutions, and if the

[15] The 30%-50% threshold range amounts to a range between 38 and 63 working days in the summer of 2026.

customer(s) in question are expected to cover the revenue shortfall for new infrastructure, these customers should be given the right to decide what type of solutions they prefer.

Why we proposed it: this criterion resonates both with the OEB's explicit guidance in the NWS Guidelines and our discussion of potential implementation issues associated with the investments supported by the CAM framework that we discussed in Chapter 2. In our view, this criterion is also consistent with a similar screen employed in Enbridge's IRP framework. We note that just because we recommend that the projects that meet this criterion be taken out of the general screening process, we expect that the regular customer connection process is a more appropriate venue for this analysis – where relevant and consistent with specific customers' preferences.

How we chose the threshold values: there are no threshold values in the context of this screening test.

5.2.7. Test 6: Technical Pre-Requisite Fit Test

Plain language definition: can the contemplated NWS option be deployed without requiring any material supporting capital or OM&A spend, which the utility did not otherwise plan to make in the medium term?

Why we proposed it: we have raised the issues of pre-requisite and co-requisite investments and the member utilities' different starting positions throughout this report. Given the simultaneous pressures of aging infrastructure, electrification enablement, and energy affordability (among others) that the utilities face, we felt that it was appropriate to feature the issue of enabling investments in our framework. Moreover, we believe that this issue resonates with a principle we discuss in Chapter 2 in response to the IESO's screening criterion that states that generation NWS can only be considered up to the size that can be accommodated by the existing system. Finally, and as noted in several junctures in our report, CRA strongly believes that distributors are entitled to have discretion as to their system planning and execution strategy, and specifically investment pacing and prioritization. Potentially requiring a distributor to fast-track a technology investment they were not otherwise planning to do for some time contradicts this principle.

5.2.8. Test 7: Utility-Specific "Wild Card" Fit Test

We left this criterion as a potential placeholder for any other considerations that member utilities may feel would supplement our recommended framework and make it more relevant for their specific operating and strategic circumstances. As an example in Table 6 of what this measure could entail, we raised a hypothetical of whether ownership of FOTM storage assets is consistent with a utility's asset management strategy at a given point in time. While the example is hypothetical, and we are aware that multiple CLD members own and operate BESS systems, in selecting this example we wanted to highlight the importance of utilities exercising strategic discretion as to the asset investment trade-off decisions they may face. While energy transition and technological progress create a variety of new opportunities for utilities to explore and leverage, they remain the stewards of safe, reliable and affordable operation of their entire systems. As such, CRA expects that trade-off decisions between investments in conventional and new digital infrastructure will become increasingly more commonplace for utilities. It is important that utilities face these trade-off decisions with clarity that comes from detailed and meticulous planning, but also – with confidence to take steps that they believe are in the best interest of their customers.

5.3. Concluding Observations

Given that our list of hypothetical investments used in the Phase 1 description screen is not grounded in any specific capital work plan, CRA lacks the detail to showcase how these

projects would fare through our Part 2 screening framework. However, our practical application of this framework can be observed in Addendum A to this report, where we evaluate Elexicon's planned 2027-2031 capital work program through our entire recommended framework.

Overall, we believe that the proposed framework achieves the five core objectives we set for ourselves at the conclusion of Chapter 2. The framework is *simple and transparent* in that it requires minimal calculations to assess a given project's fit and relies in part one on a combination of a common sense-based functional assessment and technical inputs from a well-recognized source of Ontario technical policy guidance. The framework includes both program- and project-level evaluation across the two main parts to balance processing efficiency with analytical rigour while emphasizing where NWS are most needed. As planned, the framework is built around *consistent evaluation criteria* but gives individual distributors enough room to exercise *flexibility* in selecting specific thresholds or designing the Wild Card screen, if desired. Our framework also prioritizes the *focus on primary need dimensions* by turning away all projects where NWS-related value proposition is a secondary characteristic. Finally, our proposed framework is designed to act as *a substantive BCA triage* by enabling early consideration of project economics – but without going so far as to pre-empt the rigorous analytical assessment underlying the OEB's BCA framework. Finally, and as we note throughout this report, CRA worked diligently to synthesize the insights from each of our three prongs of inquiry: Ontario policy analysis, cross-jurisdictional precedents scan, and an interview-based evaluation of our clients' technical circumstances as they relate to planning and integration of NWS. In performing these tasks, CRA's team members have explored countless hypotheses and insights that did not make it to this report's final version.

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Appendix A: Jurisdictional Review

Table 5: Additional Detail on Screening Criteria Identified in Jurisdictional Review

Criteria	Need Velocity / Lead Time Requirements	Need Size/Scale	Need Duration	Cost Effectiveness
California	3-5 years for IDER Incentives Pilot, though recognizes that short-term needs within 18-months could be addressed by NWS if necessary mechanics are already in place	N/A	Short, well-defined seasonal peaks are ideal. DERs are most effective for localized overloads during predictable peak hours or seasonal windows	PG&E pilot project with 85% threshold
New York	18-24 months for small projects, 36-60 months for large (Central Hudson & Con Edison)	N/A	N/A	N/A
Vermont	2–10 years	Transmission projects capped at 25%, none for distribution (RMI)	N/A	N/A
Hawaiian Electric	N/A	Favorable: up to 5 MW or 4 hour duration, Moderate/uncertain: 5-10 MW or 4-8 hour duration	Opportunities with smaller peak capacity, shorter-duration needs, and fewer dispatches are the best fit	Evaluate project economics by quantifying the deferral value of eligible transmission and distribution capital projects and other avoided costs to inform sourcing choices.
Liberty NH	Minimum 24 months	Projects capped at 20% of area load (RMI)	N/A	N/A
IESO	Minimum 2 years. Feasibility depends on procurement mechanisms	CDM screened in for <2% of annual load; DG limited by transformer station connection space; transmission resources not constrained	N/A	N/A
Eversource	Minimum 12 months	Size thresholds limit applicability to small projects due to reliability concerns; Varies by NWS type: i.e., when applied to an ES feeder, aggregated DER must be </=33% min load	Short duration (<3-4 hours), or limited need frequency (10-60 times per year)	N/A

Criteria	Need Velocity / Lead Time Requirements	Need Size/Scale	Need Duration	Cost Effectiveness
National Grid (RI)	Minimum 30 months	Projects capped at 20% of area load	Bridge deferral projects	Max of 60% of traditional solution deferral value
Avangrid (NY, ME, CT)	Minimum of 36 months	N/A	N/A	N/A
Niagara Mohawk Power Corporation (National Grid)	Minimum of 18 months	N/A	N/A	The MADC study estimates marginal system relief value by comparing the required relief to the cost of the traditional investment the company would otherwise make to address the forecasted constraint

EXHIBIT 2B - TAB 3 - SCHEDULE 5: APPENDIX B
2027-2031 DSP NWS PRE-SCREENING RESULTS

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2027-2031 DSP Program and Project NWS Pre-Screening Report

Addendum A to the Non-Wires Solutions Pre-Screening Methodology Report

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CRA Project No. 104025

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Executive Summary

This document summarizes the Non-Wires Solutions (NWS) pre-screening assessment that Charles River Associates International (CRA) performed on behalf of Elexicon Energy Inc. (Elexicon). CRA examined Elexicon's 2027-2031 Distribution System Plan (DSP) for pre-screening opportunities for displacing or deferring conventional grid investments with NWS using the process we describe in the *Non-Wires Solutions (NWS) Pre-Screening Methodology Report* ("the main report"). To enable the screening, Elexicon provided us with DSP program narratives for 10 programs, which were comprised of 41 projects. General Plant investments did not undergo pre-screening. The DSP narratives were our primary source of technical information on the projects we analyzed. At the conclusion of the pre-screening work, three projects remained indicating opportunities where NWS could offer a potential alternative, subject to findings of further assessments. Consistent with the Ontario Energy Board's (OEB)[1] guidelines, these projects are now undergoing more detailed Benefit Cost Analysis (BCA) work. The projects that passed the end of the pre-screening process are:

1. **Substation Growth: Bradshaw MS**

   Elexicon's load forecast estimates that the existing capacity of the 13.8kV system in the Bowmanville region is not sufficient to sustain the projected load growth. The peak load of the 13.8kV system is forecasted to be 44MW in 2025 and rise to 58MW in 2031. Peak load in the region will exceed the maximum station capacity rating starting in 2026. If a transformer is out of service in the area, the peak demand is forecasted to be greater than available capacity starting in 2027 by violating the N-1 planning criteria. Elexicon proposes investing $8.5M to address these capacity constraints by increasing the existing transformation capacity at Bradshaw MS to 25 MVA by 2031.

2. **Distribution Capacity and Reliability Enhancements: Feeder Capacity[2]**

   Elexicon plans to invest $35M in a series of feeder enhancements across its service territory to expand system capacity, relieve thermal and voltage constraints, and support both residential and industrial growth. The proposed investments focus on upgrading feeder segments, adding new circuits, and reinforcing supply paths to ensure the system can accommodate future load demand while providing adequate redundancy. By strengthening feeder capacity, Elexicon seeks to enhance resiliency and prepare the grid for long-term growth. Among the target areas are system upgrades in Belleville, Whitby, and Pickering.

3. **Distribution Capacity and Reliability Enhancements: Undersized Conductors**

   Approximately $11M[3] is planned for investment to replace 12 km of undersized conductors in critical areas with capacity and contingency constraints. Upgrading conductor size reduces line losses, mitigates voltage drops, and increases feeder capacity during peak

[1] Ontario Energy Board, Benefit-Cost Analysis (BCA) Framework for Addressing Electricity System Needs, 2024

[2] Note that portion of the Distribution Feeder Capacity and Reliability Enhancements segment associated with Animal Guards and Lightning Arrestors has been screened out, while Feeder Capacity and Undersized Conductors passed the pre-screening process.

demand. Larger conductors also support distributed energy resource (DER) integration, ensuring the grid can handle bidirectional power flows.

Figure 1 below provides a summary overview of the outcomes of our pre-screening process. Most of the projects were screened out at the *Technical Fit Test* screening stage due to their underlying capital investment need being either functionally or technically unsuitable for NWS intervention. The bulk of these projects were classified as System Renewal, with a smaller share of System Access and System Service projects being screened out as well.

During the *Need Primacy Fit Test*, the System Expansion program and Mobile Station project were screened out since NWS are incapable of addressing the primary need drivers associated with these programs. The *Need Velocity Fit Test* screened out two substation growth projects where the planned in-service date is within the 36-month threshold used for this test. The final test in which projects were screened out was the *Event Frequency Fit Test*, where two additional Substation Growth projects were screened out since they are required to enable greenfield developments that will have to support continuous 24/7 load profiles that NWS cannot reasonably accommodate. Table 1 summarizes the results of the pre-screening.

Table 1:Summary of Screening Process Results by Screen

	# of Programs / Projects Screened Out	**Capex Forecast ($M)**	**Share of Total NWS-Eligible Capex (%)**
Phase 1: Technical Fit Test	30	$394.71	61.5%
Phase 2:			
Screen 0: Materiality Screen	0	$0.00	0%
Screen 1: Need Primacy Fit Test	4	$76.57	11.9%
Screen 2: Need Velocity Fit Test	2	$10.43	1.6%
Screen 3: Event Frequency Fit Test	2	$105.94	16.5%
Screens 4-7	0	$0.00	0%
Total	**38**	**$587.65**	**91.5%**
Complete Programs Screened Out		$587.65	91.5%
Segments Screened out from BCA-eligible programs due to timing (Need Velocity)		$20.14	3.1%
Total Investments Screened Out		**$607.79**	**94.7%**
Total System Access, Renewal and Service Investments		$642.12	
Total Screened in	**3**	**$34.33**	**5.3%**

1. Introduction

1.1. Background and Purpose

CRA is pleased to provide this addendum to Non-Wires Solutions Pre-Screening Methodology Report ("the main report") we prepared for Elexicon. In this addendum we apply the pre-screening framework we developed in our main report to Elexicon's proposed 2027-2031 DSP investments, excluding General Plant.

In preparing this addendum, our primary objective was to identify the projects (and their underlying system needs) that warrant further evaluation for potential fit with an NWS. Our secondary objective was to stress-test the pre-screening framework we recommend in our main report by applying it to the real-world investment plan developed by Elexicon.

1.2. Our Process

1.2.1. Elexicon's capital evidence structure and its impact on our analysis

Elexicon's DSP breaks down its overall capital work program into programs, segments, and projects. Some investment categories are presented at a consolidated program level (e.g. Overhead System Renewal, Voltage Conversion, etc.) where individual projects are scoped out for execution closer to the actual construction time each year. Others, such as the Substation Growth Program, are already comprised of discrete projects that target interventions in specific substations. We applied our pre-screening framework to the most granular level of assessment available for a given type of an investment – be it program- or project-level. We note that this approach aligns broadly with our overall recommendations in the main report, where we argue that it is appropriate and efficient for an NWS pre-screening framework to screen out entire programs that are not structurally suitable for being addressed with NWS, provided the reasons for doing so are objective and transparent. Overall, we see it as reasonable that more granularity is available sooner for larger, discrete investment needs impacted by lengthy equipment lead times, than for those where a multitude of candidate locations are possible, and design and procurement timelines are less onerous.

1.2.2. CRA's Interaction with Elexicon during the pre-screening work

Elexicon supplied us with the relevant business cases comprising its 2027-2031 DSP approximately three weeks after we shared our recommended pre-screening framework with the company. As such, we developed our framework without the knowledge of specific projects and programs it would be applied to. Similarly, Elexicon's DSP business cases were prepared with no knowledge of the pre-screening process they would undergo.

Once Elexicon shared its DSP narratives and supplied us with the utility-specified numerical thresholds that four of our recommended pre-screening tests call for[4], we did not communicate with its technical staff until our initial screening was completed. CRA applied the screens sequentially, eliminating investments that failed each stage before moving to the next. If a project/program did not pass a given screen, it was removed from the screening process and

[4] See Section 4.2 of CRA's main report.

the rationale for removal was documented. The projects that remained following the application of the entire set of screens were identified as being eligible for the BCA analysis.

When sharing the results of our pre-screening analysis with Elexicon, we verified our understanding of key features of its business cases to ensure that our analysis did not inadvertently misapply any criteria. Having done so, we confirmed that no further modifications to the screening process were required. Elexicon did not challenge the results of our pre-screening process once we shared them with their technical and regulatory teams. The company noted that they had originally contemplated adding a custom, seventh utility-specific screen which our recommended framework permits. While the custom utility-specific screen was not used in this screening run, CRA sees no reason why Elexicon could not develop such a criterion for the framework's future use.

The three projects that have passed the entire pre-screening process are currently undergoing the BCA work as required by the OEB guidelines. We understand that Elexicon expects to share the results of BCA with the OEB and other regulatory process stakeholders once the underlying work is completed.

1.3. A brief recap of CRA's NWS pre-screening framework

CRA's recommended pre-screening framework evaluates programs and projects across two main phases: an initial functional/technical screen to assess broader NWS suitability for needs underlying proposed investments, and a subsequent evaluation phase that focuses on operational, logistical, and strategic fit between the investment needs and their proposed conventional solutions and key NWS capabilities.

The first, Technical Fit Screening phase seeks to eliminate from further consideration the programs and projects where NWS cannot offer a viable alternative based on structural factors – i.e. fundamental nature of work and the types of outcomes that a distributor seeks to prevent from occurring or seeks to bring about (e.g. preventing a failure, or ensuring sufficient connection capacity is in place).

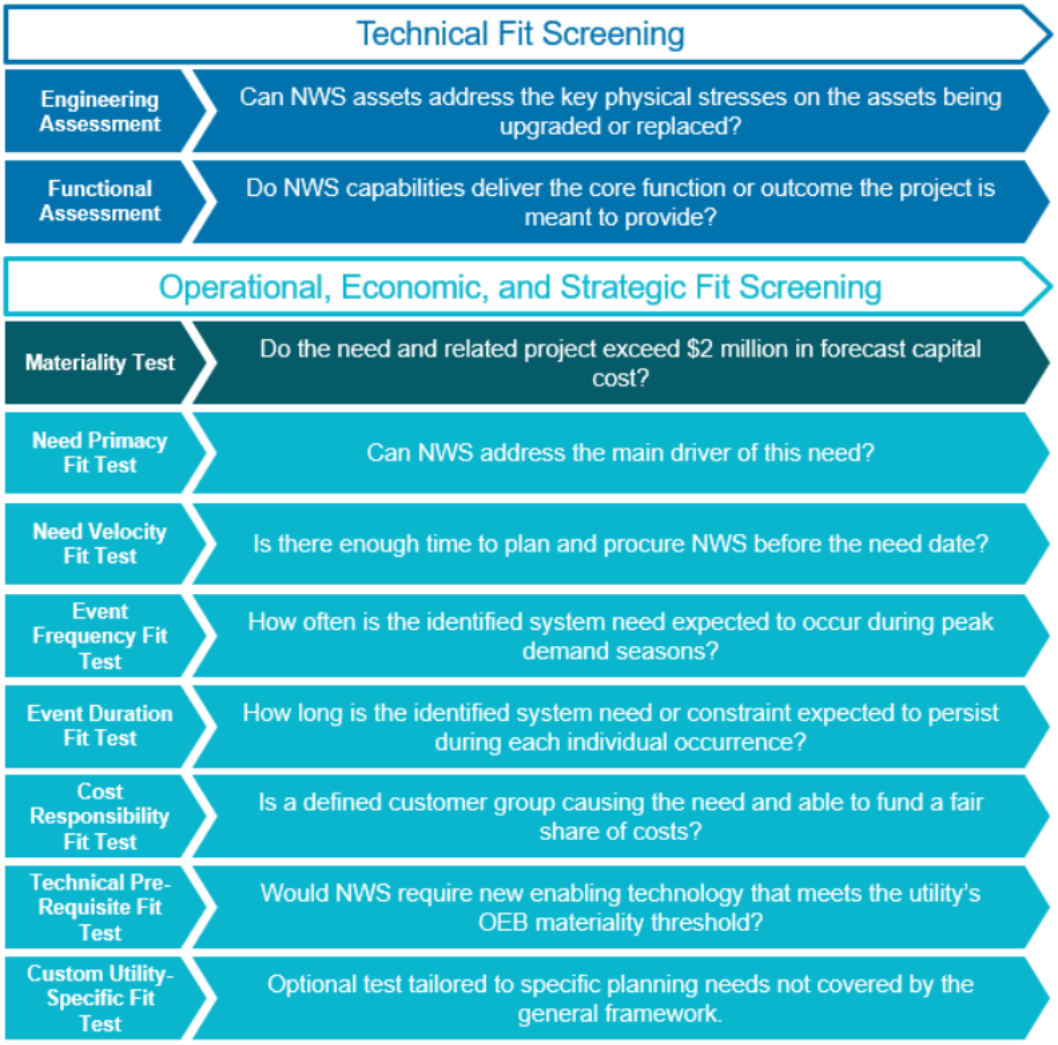
In our main report we separated the Technical Fit screen into two components: the Functional Assessment and the Engineering Assessment. Under the functional assessment, we defined a list of generic investment projects that distributors typically undertake, and separated them into four functional categories:

- *New Service*: Physical enablement of electricity service to new customers.
- *Lifecycle Management*: Removal of threat to service continuity or safety due to physical damage or structural degradation of internal or external components.
- *Capacity Management*: Addressing the insufficient physical properties to accommodate downstream demand without sacrificing asset lifecycle.
- *Functionality Upgrade*: Enhancing operationally deficient performance features of the existing system that affect operational efficiency or outcomes for end users.

While these categories closely match the OEB's System Access, System Renewal and System Service categories used in the DSP, our categorization separates System Service projects into two main functional categories, only one of which (Capacity Management), can be potentially addressed with NWS. Having separated the typical projects across these four categories, we further defined in plain language the main functional outcome that each type of investment sought to deliver (e.g. "digital measurement and recording of power consumption, voltage, or current readings." for advanced metering investments, or "provision of safe access to and environmental separation of distribution transformers located below-grade" for transformer vault lifecycle management investments). Based on this functional categorization, we were able

to assess whether NWS can perform the core task that a given system need (and associated conventional investments employed to address it) call for.

Figure 1: NWS Pre-Screening Framework applied to Elexicon's DSP



As an additional technical lens applicable primarily to System Renewal and System Service investments (which called Engineering Assessment), we considered the degree to which electrical loading and mechanical stress influence the degradation of various types of equipment over time. CRA recommended eliminating from further screening the investment needs where mechanical stress mitigation was a significant investment driver, since NWS are unable to provide this function. Alternatively, for needs where electrical loading mitigation was a significant investment driver, we recommended advancing the associated system needs to further stages of our screening framework. In exploring the degree of mechanical and electrical stress on a given asset category, CRA relied on degradation impact assessments published in a seminal 2010 Kinectrics report "Asset Depreciation Study for the OEB", which the OEB commissioned to help establish the range of applicable depreciation lives across the most common distribution asset classes. In cases where neither mechanical stress nor electrical loading were seen as determining factors in asset interventions, CRA relied on the Functional Assessment results alone.

At the start of Phase 2 of the screening process, all remaining programs/projects are screened for materiality, which entails removing from further consideration all projects below the $2-million cumulative cost forecast threshold over the five-year DSP planning horizon.

Phase 2 then assesses the remaining programs and projects based on operational and logistical criteria to determine whether NWS would be a viable alternative option. The phase is comprised of six mandatory screens and a seventh, optional utility-specific screen that a distributor may choose to employ. Figure 1 on the preceding page provides the visual representation of the entire screening framework. As noted above, Elexicon elected not to utilize the optional seventh screen at this time. Four of the screens feature numerical thresholds where CRA recommended threshold ranges, leaving it to Elexicon to select the specific threshold values. Projects that pass all screens are subject to a BCA analysis confirming the cost effectiveness of NWS relative to traditional solutions, and other assessments, as may be applicable.

2. Pre-Screening Process Phase 1

Before proceeding to the pre-screening itself, we present a brief overview of the programs and projects comprising Elexicon's capital work program that underwent our analysis. At the time of assessment this amounted to 10 programs comprised of 41 projects:

System Access

A1. Externally Initiated Plant Relocation

Elexicon's Externally Initiated Plant Relocation program covers the mandatory costs for Elexicon to relocate and construct its distribution equipment to accommodate infrastructure developments by third parties.

A2. Customer Connections

These are mandated investments in the distribution system to enable residential, commercial, and industrial customers to connect loads, generation, and storage facilities to Elexicon's distribution system. The program includes connection services and connection assets including overhead wire and underground cable, metering technologies, transformers, poles, associated hardware and related infrastructure.

A3. System Expansion

Investments in system expansion are initiated when capacity constraints within the existing distribution system require upgrades or additional infrastructure to accommodate new customer connections or increased load from existing customers. These investments are legal service obligations for Elexicon under the Distribution System Code (DSC), which mandates timely and efficient fulfillment of connection requests.

System Renewal

R1. Substation Renewal

This program manages station-level failure risks through targeted replacement of high-risk station assets, where failure would result in unacceptable safety, reliability, or environmental risk. Station failures may cause extended outages or brownouts for customers served by the station. Replacing a failed station asset often involves extended timelines due to site-specific complexities and long lead times for equipment procurement.

R2. Underground System Renewal

This program involves strategic investment designed to proactively replace, and where appropriate, rejuvenate, high-risk, aging, and poor and very poor condition underground infrastructure that has reached or exceeded its Typical Useful Life (TUL). The program addresses underground equipment, including direct-buried cables, transformers, and switchgear that have been identified as being in a degraded condition during the future rate period from 2027-2031, or that have significantly contributed to system reliability challenges.

R3. Overhead System Renewal

A strategic investment program designed to proactively replace high-risk, aging, and poor to very poor condition overhead infrastructure that has reached or exceeded its Typical Useful Life (TUL). The program addresses overhead equipment, including poles, pole mount transformers, overhead switches, overhead conductor and overhead accessories, that have been identified as being in a degraded condition during the future rate period from 2027-2031, or that have contributed to system reliability challenges.

R4. Reactive Capital

Reactive Capital provides immediate replacement for unplanned, in-service failures or assets at high-risk of failure. This program ensures the replacement of failed or near-failing assets quickly and safely to maintain system reliability and safety.

System Service

S1. Substation Growth

Investments in Substation Growth help address medium to long-term system capacity needs by investing in new stations or capacity upgrades at existing stations. The goal of this program is to increase capacity in the system with targeted investment to meet forecast load.

S2. Grid Enhancements

The Grid Enhancement program involves strategic investments in distribution and station modernization, system capacity and reliability improvements, and targeted station relay upgrades. This program includes the deployment of automated switches, fault detection technologies such as Communicating Fault Circuit Indicators (CFCIs) and Fault Circuit Indicators (FCIs), self-resetting fuses, smart reclosers, substation relay replacements, station modernization, and distribution capacity and reliability enhancements.

S3. Voltage & System Conversion

The Voltage Conversion program works in tandem with the Substation Growth program. New and upgraded municipal stations create the supply sources that enable higher voltage operation, while conversion projects expand capacity at the distribution level to ensure that customer demand can be met.

2.1. Screen 1: Technical Fit

The Technical Fit Screening test operates by assessing the extent to which NWS can technically and/or functionally meet the needs that system needs and their traditional solutions seek to address. The purpose of this screen is to eliminate programs or projects where NWS are simply incapable of performing the functions that the investment needs call for. In describing the Technical Fit Screening test our main report, we outlined a set of generic distribution investment projects which we assessed for fit with NWS in two ways:

- *Functional Assessment*: by identifying in plain language what functional outcome(s) needed to occur for an investment to satisfy the core need and then exploring whether NWS could achieve those outcomes. For instance, if an investment was needed to

physically relocate existing assets or measuring customers' electricity consumption, NWS would not offer a functional alternative as they are unable to perform those functions.

- *Engineering Assessment*: as an additional layer of analysis (where applicable), we explored the extent to which different types of investments addressed the two most common types of physical asset degradation factors – namely Mechanical Stress and Electrical Loading. Where Mechanical Stress was a significant degradation factor – on its own or in combination with other stressors – we concluded that NWS would not be a viable option for addressing the underlying need given their inability to address mechanical stress.

Based on the combination of these two types of assessments, our main report opined on whether our generic list of common types of distribution investments should be screened out from further consideration for NWS opportunities or continue assessment to our framework's second phase. We applied the same considerations when assessing Elexicon's 2027-2031 work program. In most cases, we were able to simply identify an equivalent Elexicon program or project to a generic investment type that we opined on in our main report and replicate our recommendations as to its passing of Technical Fit screening test as shown in Table 2 below. There were, however, six programs or segments in Elexicon's DSP that were not explicitly contemplated among our generic examples in the main report. This required us to examine their core asset components and/or functional features in a manner consistent to the analysis applied in the main report to assess their potential fit with NWS more closely. The investment categories in question were:

- Reactive Capital
- Animal Guards
- Lightning Arrestors
- Station Lifecycle Management
- Wide Area Capacity
- Mobile Stations

We screened out *Reactive Capital* program from further consideration due to its lack of functional fit with capabilities that NWS possess. Since reactive capital work typically involves restoring interrupted service by replacing failed or damaged physical equipment with its equivalents that are in good working order, NWS cannot be expected to perform the same function on a permanent basis. Even if an NWS like a battery energy storage system, can help partially mitigate the impact of an upstream outage, this temporary relief does not obviate the need to address the physical failure, making NWS functionally inadequate as an alternative. Accordingly, we eliminated Reactive Capital investments from further consideration.

We confidently eliminated *Animal Guards* and *Lightning Arrestors* from further consideration as well, due to the lack of functional fit with NWS capabilities, as there are no types of NWS that could reasonably prevent animal contacts or reduce the damage of lightning strikes on distribution line and/or station equipment.

Moving to *Station Lifecycle Management* – this program entails comprehensive replacement of stations equipment based on demographics, assessed condition or design obsolescence of the existing assets with the aim of preventing in-service failures or safety incidents. Given that comprehensive station rebuilds include replacement of equipment that is affected by both mechanical (e.g. circuit breakers) and electrical degradation (e.g. power transformers), we determined NWS to not be a suitable option for deferring or eliminating the overall need for station renewal as an integrated investment. This is consistent with our main report where we recommend screening out investments driven in equal parts by mechanical stress and electrical loading issues, since NWS can only address one of the two.

We advanced the *Wide Area Capacity* program to the next phase of our screening process since the program primarily seeks to enable anticipated electricity demand growth than what is possible under the current system arrangements. While the program also contemplates replacement of aged or deteriorated equipment during the upgrades, NWS could potentially play a role in deferring the investment – subject to other considerations explored in the later stages of the framework.

The final investment type that we did not contemplate among the generic examples in our main report was *Mobile Stations*. Utilities procure mobile stations to support planned construction outages on the permanent facilities that require intervention. They may also be used to provide emergency load support during unplanned station outages. Given that this investment type seeks to enable load flexibility and system resilience through application of temporary solutions that can address multiple needs during their lifecycle, we advanced it to the next screen as well. When it comes to all other programs and projects – we assessed their technical fit with NWS in the manner consistent with the examples provided in our main report. Table 2 provides a comprehensive overview of the Technical Fit screening test across all the programs and projects examined.

In total, we screened out five programs and 25 projects at this stage based on our assessment of NWS having insufficient potential of addressing the functional or technical properties of the core equipment and intervention modes proposed. These include two system access programs (*Externally Initiated Plant*, *Relocations and Customer Connections*), two system renewal programs (Underground System Renewal and Overhead System Renewal), 17 Substation Renewal projects, and five system service projects (Distribution Modernization, Station Modernization, and Port Hope, Belleville, and Pickering Voltage System Conversions). At the conclusion of the Technical Fit screen, a total of three programs and ten projects remained.

Table 2 describes the outcomes of the Technical Fit Screen analysis.

Table 2: Screen 1: Technical Fit Screen

Program Name	Project Name (if known)	Core Function To be Enabled	Outcome
System Access			
Externally Initiated Plant Relocations	Multiple	Physical removal and reinstallation of existing overhead or underground facilities driven by third party requests.	**Screened Out** – NWS incompatible with 3rd party requests to relocate infrastructure.
Customer Connections	Multiple	Physical integration of new customer loads with the distribution system for continued drawing of power	**Screened Out** – NWS cannot replace the need for physical coupling of customer facilities with the distribution system.
System Expansion	Multiple	Extension of dedicated physical assets into a vacant area with expectation of eventual interconnection of new loads.	**Continue Assessment** - Potential NWS Impact or Inconclusive
System Renewal			
Substation Renewal	Station Deficiencies	Safe and Reliable Operation of Stations: through timely replacement of small deficient equipment identified through inspections.	**Screened Out** - NWS cannot compensate for physical equipment defects.

Program Name	Project Name (if known)	Core Function To be Enabled	Outcome
	DC System Replacement	Safe and Reliable Operation of Stations: through timely replacement of station batteries and charging equipment assessed to be in poor condition.	**Screened Out** - NWS provide no value in extending the lifecycle of batteries required to operate critical protection devices.
	Shuter	Safe and Reliable Operation of Stations: through construction of a new building to improve safety and efficiency during maintenance work and provide adequate space for additional protection and telemetry requirements.	**Screened Out** – NWS incapable of addressing spatial restrictions in the existing physical station environment.
	Catherine	Safe and Reliable Operation of Stations: through a complete rebuild of a station, including replacement of a power transformer currently in Poor condition, modernization of transformer protection configuration and installation of oil spill containment.	**Screened Out** – NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
	Fairport	Safe and Reliable Operation of Stations: through a complete rebuild to address egress cable exposure, flood-prone location, and switching equipment beyond typical useful life.	**Screened Out** – NWS cannot address the operating limitations posed by physical location, legacy design limitations or aged assets.
	Edgehill	Safe and Reliable Operation of Stations: through a complete rebuild to address condition degradation on one power transformer and tap changer, along with deteriorated condition and safety risks of other equipment.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
	Cavan South	Improved System Efficiency: through decommissioning of a substation that will become redundant once local area conversion from 4.16 kV to 13.8 kV is completed.	**Screened Out** –NWS cannot perform a physical decommissioning function
	Garden	Safe and Reliable Operation of Stations: through a complete rebuild to address Circuit Breaker condition degradation, lack of requisite work clearances and absence of oil spill containment infrastructure	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
	Bigelow	Safe and Reliable Operation of Stations: through a partial rebuild of station assets exhibiting signs of significant deterioration, including renewal, placement and insulation of internal and egress cables	**Screened Out** - NWS cannot compensate for legacy design deficiencies and outage risks stemming from aged and deteriorated equipment.
	Crandell	Safe and Reliable Operation of Stations: through a complete rebuild to address a legacy transformer protection configuration, absence of oil spill containment infrastructure and deteriorated legacy switch and station egress cable assets.	**Screened Out** - NWS cannot compensate for legacy design deficiencies and outage risks stemming from aged and deteriorated equipment.
	Riverside	Safe and Reliable Operation of Stations: through a complete rebuild to address a power transformer beyond useful life and legacy	**Screened Out** - NWS cannot compensate for legacy design deficiencies and outage risks

Program Name	Project Name (if known)	Core Function To be Enabled	Outcome
		design breakers and aged deteriorated feeder cables.	stemming from aged and deteriorated equipment.
	Uxbridge East	Safe and Reliable Operation of Stations: through a complete rebuild to address a power transformer beyond useful life, a legacy protection configuration, and other evidence of asset degradation.	**Screened Out** - NWS cannot compensate for legacy design deficiencies and outage risks stemming from aged and deteriorated equipment.
	Town Centre	Safe and Reliable Operation of Stations: through a complete rebuild to address the tie switch and line switch in Very Poor condition and the lack of oil spill containment.	**Screened Out** - NWS cannot compensate for legacy design deficiencies and outage risks stemming from aged and deteriorated equipment.
	Herchimer	Improved System Efficiency: through decommissioning of a substation that will become redundant once local area conversion from 4.16 kV to 13.8 kV is completed.	**Screened Out** –NWS cannot perform a physical decommissioning function
	Cascade	Safe and Reliable Operation of Stations: through a complete rebuild to address the power transformer past typical useful life and enable voltage conversion in the area.	**Screened Out** – NWS cannot compensate for the existing equipment becoming redundant post-voltage conversion.
	Westney Heights	Safe and Reliable Operation of Stations: through a complete rebuild to address a leaking power transformer and station cable infrastructure in poor condition.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
	Uxbridge West	Safe and Reliable Operation of Stations: through a complete rebuild to address aged and deteriorated assets at a station critical for maintaining local area supply redundancy.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
Underground System Renewal	N/A	Line Equipment Lifecycle Management – reliable conveyance of electricity through timely and proactive replacement and/or rejuvenation of underground or submarine assets in Poor or Very Poor Condition.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
Overhead System Renewal	N/A	Line Equipment Lifecycle Management – reliable conveyance of electricity through timely and proactive replacement and/or rejuvenation of overhead assets in Poor or Very Poor Condition.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
Reactive Capital	N/A	Reliability and Performance Continuity: through physical system integrity, maintained via restoration of service using the original following an unexpected asset failure.	**Screened Out** - NWS cannot compensate for the outage risks stemming from aged and deteriorated equipment.
System Service			

Program Name	Project Name (if known)	Core Function To be Enabled	Outcome
Substation Growth	Uxbridge North MS	Capacity During Contingencies – ensuring operation within prescribed rating limits during peak demand periods coinciding with N-1 contingencies in the area.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Foster MS	Capacity During Normal Conditions – ensuring operation within prescribed rating limits during normal conditions from organic load growth on the 13.8 kV system and scheduled absorption of the 4.16 kV system load following area voltage conversion.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Mobile Station MS	Construction Flexibility and Service Continuity – deployment of locationally flexible transformation capacity to enable support of prolonged outages in multiple areas over time.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Port Hope MS	Capacity During Normal Conditions – ensuring operation within prescribed rating limits during normal conditions from organic load growth on the 27.6 kV system and scheduled absorption of the 4.16 kV system load following area voltage conversion.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Bradshaw MS	Capacity During Normal Conditions – ensuring operation within prescribed rating limits during normal conditions from organic load growth on the 13.86 kV system.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Winchester West MS-Stage 1	Capacity for Greenfield Load: existing load transfers, new feeder and new transformer station construction.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Winchester West MS-Stage 2	Capacity for Greenfield Load: new feeder construction and addition of a new power transformer, among other infrastructure.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Transformer Station in North Whitby	Capacity for Greenfield Load: new transformer station construction to meet the load growth needs from multiple new developments.	**Continue Assessment** - Potential NWS Impact or Inconclusive
Grid Enhancements	Distribution Modernization	Enhanced system operation efficiency through the expanded ability to reduce the impact of system outages through automated restoration of service to parts of circuits equipped with automated / intelligent devices, and/or enhanced remote system status monitoring.	Screened Out - No expected impact on functional properties from NWS.
	Station Modernization	Enhanced performance, reliability and long-term sustainability of critical station assets through deployment of online condition monitoring infrastructure, data accumulation and data transfer infrastructure.	Screened Out - No expected impact on functional properties from NWS.

Program Name	Project Name (if known)	Core Function To be Enabled	Outcome
	Distribution Capacity and Reliability Enhancements-Feeder Capacity	Increase of line equipment's current carrying capability through replacement with a larger / higher-rated unit - potentially independently of demographics or condition, and addition of redundant supply paths to reduce the impact of outages.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	Increase of line equipment's current carrying capability through replacement with a larger / higher-rated unit - potentially independently of demographics or condition.	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Distribution Capacity and Reliability Enhancements-Animal Guards	Prevention of animal contacts with energized equipment by way of installing physical obstacles for animals to climb and/or mount the assets.	**Screened Out**- NWS cannot perform the requisite function of an animal contact barrier.
	Distribution Capacity and Reliability Enhancements-Lightning Arrestors	Protection of equipment from high voltage surges typically caused by lightning events.	**Screened Out** – NWS cannot perform the function of limiting the damage from lightning strikes.
	Station Upgrades	System Efficiency, Safety and Reliability through replacements of old and obsolete station protection relay technology.	**Screened Out** – NWS cannot restore the physical integrity of the system affected by asset failures or damage.
Voltage & System Conversion	Port Hope	Increase of equipment's current carrying and transformation capacity to enable phaseout of legacy / obsolete lower-voltage equipment and facilitate load growth.	**Screened Out** – lack of technical properties fit.
	Belleville	Increase of equipment's current carrying and transformation capacity to enable phaseout of legacy / obsolete lower-voltage equipment and facilitate load growth.	**Screened Out** – lack of technical properties fit.
	Pickering	Increase of equipment's current carrying and transformation capacity to enable phaseout of legacy / obsolete lower-voltage equipment and facilitate load growth.	**Screened Out** – lack of technical properties fit.

2.2. Screening Process Phase 2

2.2.1. Gate 0: Assessment Materiality Screen

Each of the three programs and ten projects that entered Phase 2 of the screening process exceeded the $2 Million threshold over the five-year DSP period, and therefore passed Gate 0 of Phase 2. As such, no projects or programs were screened out at this juncture.

The results of Gate 0 are found in Table 3 below.

Table 3: results of Gate 0

Program Name	Project Name	Capital Investment Category	Total Capital Cost 2027-2031 ($M)	OEB Mandated Screen
System Expansion	Multiple	System Access	$54.10	**Continue Assessment** – spend profile exceeds the $2M threshold.
Substation Growth	Uxbridge North MS	System Service	$7.70	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Foster MS	System Service	$7.99	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Mobile Station MS	System Service	$3.36	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Port Hope MS	System Service	$11.12	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Bradshaw MS	System Service	$8.47	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Winchester West MS-Stage 1	System Service	$2.73	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Winchester West MS-Stage 2	System Service	$3.73	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Transformer Station in North Whitby	System Service	$102.21	**Continue Assessment** – spend profile exceeds the $2M threshold.
Grid Enhancements	Distribution Capacity and Reliability Enhancements-Feeder Capacity	System Service	$35.00	**Continue Assessment** – spend profile exceeds the $2M threshold.
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	System Service	$11.00	**Continue Assessment** – spend profile exceeds the $2M threshold.

2.2.2. Test 1: Need Primacy Fit Test

The Need Primacy Fit Test assesses whether NWS is a suitable solution to address the main need driver underlying a given investment need and/or conventional solution proposed to address it. This is in line with expectations in the OEB's NWS Guidelines, which encourages distributors to define the types of system needs where NWSs have the greatest potential to meet the system need.[5] The role of this screen is to eliminate from further consideration the projects where an NWS may provide some degree of complementary benefits but cannot in itself address the core reason why the need arises.

[5] OEB NWS Guidelines, 2024, p.8

Among the programs and projects that remained in consideration at the current stage of our screening analysis, we saw investments characterized by three primary drivers, namely:

- Capacity Constraints
- Reliability Improvements
- Customer Requests

Across these three drivers, NWS investments cannot satisfy the primary drivers behind customer requests. The customer requests fall under the *System Expansion* program, where new customer connections require construction of physical infrastructure that enables drawing of power from Elexicon's distribution system. While NWS deployment could potentially help reduce the new equipment's loading ratings, it cannot replace the physical facilities that connect new customers to the distribution system.

Moreover, and as we discuss in our main report, the NWS Guidelines convey the OEB's expectation that use of NWS in the context of customer connections should incorporate customer preferences – including where customers are in favour of (and willing to fund the applicable contribution for) traditional grid solutions.[6] Based on these factors, we confidently screened out the *System Expansion* program from further consideration. We note, however that we expect that Elexicon would explore any applicable NWS options on a project-by-project basis if specific customers express the preference for doing so during the connection process.

At this stage we have also screened out the *Mobile Stations* program earlier. We did so for two main reasons. First, mobile stations arguably represent a form of an NWS in and of themselves, as they enable locationally flexible and targeted load pickup to support planned or emergency outages on existing station equipment. Second, in performing their functions, mobile stations can sustain all or most of the loading experienced by the permanent assets they replace on a prolonged and continuous basis. No other form of an NWS solution can perform such a function. By virtue of being a type of NWS and performing a function that no other form of NWS can replicate, we saw it as reasonable to eliminate the Mobile Stations program from further consideration.

Consistent with our discussion of eligible NWS use cases in the main report, we have advanced to the next screen the remaining seven projects where the primary drivers were either Capacity Constraints or some form of Reliability Improvements. The results of the Need Primacy Fit Test are summarized in Table 4 below.

Table 4: Test 1: Need Primacy Fit Test Results

Program Name	Project Name	Primary Driver	Outcome
System Expansion	Multiple	Customer Service Requests	**Screened Out** - NWS cannot fully address Customer Service Requests alone.
Substation Growth	Uxbridge North MS	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
	Foster MS	System Voltage Conversion	**Screened Out** - NWS cannot compensate for the physical infrastructure features of in voltage conversion.

[6] *Ibid.* p. 10

Program Name	Project Name	Primary Driver	Outcome
	Mobile Station MS	Reliability (Construction Enablement)	**Screened Out** - NWS cannot compensate for the physical infrastructure features of voltage conversion.
	Port Hope MS	System Voltage Conversion	**Screened Out** - NWS cannot compensate for the physical infrastructure features of voltage conversion.
	Bradshaw MS	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
	Winchester West MS-Stage 1	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
	Winchester West MS-Stage 2	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
	Transformer Station in North Whitby	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
Grid Enhancements	Distribution Capacity and Reliability Enhancements-Feeder Capacity	Capacity Constraints	**Continue Assessment** - NWS a viable option for addressing Capacity Constraints
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	Reliability Improvement	**Continue Assessment** - NWS can play a role in deferring capacity needs and facilitating reliability.

2.3. Test 2: Need Velocity Fit Test

The Need Velocity Fit Test assesses whether a distributor has sufficient lead time to pursue NWS in place of traditional solutions given the anticipated timeline within which the need is expected to arise. In CRA's main report, we recommended a Need Velocity threshold range of 36-40 months, which represented a typical range for a similar test across the jurisdictions we examined in our cross-jurisdictional scan. In practical terms, the threshold value represents a minimum timeline within which attempting to procure an NWS would be logistically and commercially feasible. In cases where a project need arises earlier than the threshold timeframe selected, NWS options are deemed to be unapplicable.

Elexicon has selected a Need Velocity test threshold of 36 months, which is at the lower boundary of the range we recommended. In discussing the rationale for this selection with the company's representatives, we understand that their decision was based on the current lead times for ordering station transformers, plus an additional eight-to-12-month planning, design and work scheduling period. Applying Elexicon's 36-month Need Velocity threshold to the company's anticipated DSP filing timing in mid-December of 2025, yields a need threshold date of January 2029. Therefore, any remaining projects with investment needs that fall before this date are screened out from NWS viability.

Two substation growth projects were screened out because their need materialization date arises in 2028. These include the Uxbridge North MS and Winchester West MS-Stage 1 projects. We advanced the multi-year investments with multiple expected candidate locations and a consistent spend profile across the DSP period through this screen (such as the Grid

Enhancements). However, we did so with an understanding that only the work commencing in 2029 would be eligible for NWS consideration, subject to the outcomes of subsequent screen runs.

At the conclusion of the Need Velocity Fit Test, five projects remained as potential NWS candidates. The results of the Need Velocity Fit Test are captured in Table 5 below.

Table 5: Test 2: Need Velocity Fit Test Results

Program Name	Project Name	Need Materialization Date	Outcome
Substation Growth	Uxbridge North MS	2028	**Screened Out** - Need Materializes Before Utility Specific Threshold
	Bradshaw MS	2031	**Continue Assessment** - Need Materializes after Utility Specific Threshold
	Winchester West MS-Stage 1	2027	**Screened Out** - Need Materializes after Utility Specific Threshold
	Winchester West MS-Stage 2	2031	**Continue Assessment** - Need Materializes after Utility Specific Threshold
	Transformer Station in North Whitby	2032	**Continue Assessment** - Need Materializes after Utility Specific Threshold
Grid Enhancements	Distribution Capacity and Reliability Enhancements- Feeder Capacity	Variable- Project Dependent (Annual Program)	**Continue Assessment -** No Discrete Materialization date. Ongoing Project Needs.
	Distribution Capacity and Reliability Enhancements- Undersized Conductors	Variable- Project Dependent (Annual Program)	**Continue Assessment** - No Discrete Materialization date. Ongoing Project Needs.

2.4. Test 3: Event Frequency Fit Test

The Event Frequency Fit Test evaluates whether the investment need anticipated over a given time horizon arises due to anticipation of discrete (and relatively infrequent) events, or an increase in the baseline need expected to be present on a continuous basis. In our main report, we originally defined the threshold value for this screen as the number of business days between May 1 and October 31 (i.e. the IESO's Summer period) during which a given need is forecasted to arise. In reviewing our recommendations, Elexicon correctly pointed out that parts of its system are winter-peaking, suggesting that we modify this criterion by replacing the specific time of the year with a more flexible reference to "peak demand seasons" which would cover both summer and winter. We agreed with this suggestion.

A forecasted number of days below our suggested 30%-50% range of peak period business days would be considered suitable for being addressed by an NWS such as Demand Response or Battery Energy Storage. A need exceeding this threshold range would, in contrast, be considered a "baseload" need – addressable more appropriately by conventional investments. In our main report, we left it up to the distributor to define the exact threshold value within our recommended range based on their specific circumstances.

While Elexicon endorsed the need for and definition of this screening criterion subject to the modifications discussed, we learned that the company's current load forecasting approach produces outputs on a more consolidated basis than what would be required to determine an individual number of days that our framework calls for. Despite this partial limitation, CRA found sufficient evidence in the company's business cases to apply this screen to the remaining projects through a modified methodology.

Specifically, among the remaining projects were two Substation Growth initiatives (Winchester West MS-Stage 2 and new Transformer Station in North Whitby), which represent greenfield capacity investments required to accommodate confirmed net new residential and commercial developments. These developments will require a level of baseload electricity service on a 24/7/365 basis, which exceeds the threshold range recommended in our test. As a result, we screened out the projects in question from further consideration using a proxy binary test of whether a project need arises from greenfield capacity enablement. As Table 6 indicates, upon the completion of the Event Frequency Fit Test, only three projects remained.

Table 6: Screen 4: Event Frequency Fit Test Results

Program Name	Project Name	Need corresponds to greenfield and/or subdivision development? (Proxy Test)	Outcome
Substation Growth	Bradshaw MS	No	**Continue Assessment** - Event Frequency Threshold Not Exceeded
	Winchester West MS-Stage 2	Yes	**Screened Out** - Investment Driven by Baseload Needs
	Transformer Station in North Whitby	Yes	**Screened Out** - Investment Driven by Baseload Needs
Grid Enhancements	Distribution Capacity and Reliability Enhancements-Feeder Capacity	No	**Continue Assessment** - Potential NWS Impact or Inconclusive
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	No	**Continue Assessment** - Potential NWS Impact or Inconclusive

2.5. Test 4: Event Duration Fit Test

The Event Duration Fit Test assesses the forecasted length of time that an average individual event underlying the need – be it an outage or a high demand occurrence – is expected to last. As we discuss in the main report, our research indicates that shorter-duration events lend themselves better to being addressed by the current suite of commercially available NWS. Our main report recommends a threshold value range between three-and-a-half and four hours.

As noted above, Elexicon's current load and reliability forecasting practices do not feature the requisite granularity to employ the recommended fit test threshold as prescribed. Though we were able to confirm that the vast majority of Elexicon's feeders have historically experienced outages that are shorter than four hours (outside of MED events), we found no compelling proxies to use for the corresponding capacity need forecast duration that the remaining projects sought to address. Since we could not assess all remaining investments in a consistent manner

given the available information, we opted to advance all three remaining projects past this screening fit test. Elexicon agreed with our approach.

We note, however, that the two projects screened out from the previous Event Frequency Fit Test would have also been screened out during the Event Duration Fit Test – as they are expected to serve baseload needs.

2.6. Test 5: Cost Responsibility Fit Test

The Cost Responsibility Fit Test explores whether a specific subset of customers (one or multiple, present or future) is responsible for the need arising and is thus expected to provide an appropriate amount of capital contribution to cover the revenue shortfall as required by the Distribution System Code (DSC). The test ensures that those responsible for the cost have agency to determine what solution is selected – provided that they are willing to cover the capital contributions associated with their preferred option. Our discussions with Elexicon confirmed that none of the three remaining projects are expected to require any capital contributions from a single customer or a specific subset of customers. As such, all three projects were advanced through this screening test as shown in Table 7.

Table 7: Test 5: Cost Responsibility Fit Test Results

Program Name	Project Name	Need triggered by a specific customer or a group of customers?	Outcome
Substation Growth	Bradshaw MS	No	**Continue Assessment** - Need Not Invoked by a Specific Customer
Grid Enhancements	Distribution Capacity and Reliability Enhancements-Feeder Capacity	No	**Continue Assessment** - Need Not Invoked by a Specific Customer
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	No	**Continue Assessment** - Need Not Invoked by a Specific Customer

2.7. Test 6: Technical Pre-Requisite Fit Test

The Technical Pre-Requisite Fit Test assesses the costs associated with acquiring, maintaining, and integrating the enabling technologies required to adopt NWS. These costs are compared against a utility-specific rate application materiality threshold to determine the scale of investment required to implement NWS should requisite technical capabilities not yet be in place. In discussing this screening fit test with Elexicon, CRA opined that with a maximum of three NWS-eligible projects remaining in the screening process at this stage, the company could likely support them with a relatively simple combination of technology, processes and partial staff resources. In our estimation, the cost of these baseline capabilities would fall below Elexicon's application materiality threshold of $0.7 million over the five-year period. As such, we passed all three remaining projects past the technical Pre-Requisite Fit Test, subject to findings of further cost estimation work expected to occur in support of BCA.

2.8. Test 7: Utility Specific Special Circumstances Screen

At this time Elexicon elected not to include a special circumstances screen in their process. All three projects that advanced from the previous screen have thus made it through to the end of the pre-screening process, and are proceeding towards the BCA step, which is outside the

scope of this Addendum. CRA understands, however, that Elexicon plans to submit the results of the BCA analysis for the OEB and stakeholder review in the coming months, once it is completed.

3. Results, Recommendations and Next Steps

The results of Elexicon's inaugural pre-screening process for NWS fit are summarized in the table below. A total of three projects – one involving a station capacity upgrade, and two contemplating feeder capacity and reliability upgrades, have passed through all of our screening test components. CRA notes, however, that merely passing the NWS pre-screening process does not confirm that NWS is an optimal path forward for the project needs in question. Instead, Elexicon can explore the practical fit between NWS and the remaining needs on a more comprehensive basis once the BCA work is complete.

Turning to our secondary objective of evaluating our recommended framework's efficiency and effectiveness upon applying it to a real-life investment program, we are satisfied with the overall results. As we discussed above, CRA encountered some data limitations that prevented us from using the full complement of analytical steps envisioned. However, the overall breadth and diversity of our framework's assessment criteria allowed us to evaluate all projects through multiple technical and operating lenses. Moreover, in some places, the clarity and simplicity of principles underlying specific assessment criteria enabled us to develop compelling proxies that could be used in place of more detailed forecasts. Finally, we were pleased that Elexicon's technical experts saw merit in the formulation of all individual screening tests, as well as their combination and sequencing. Table 8 below summarizes the results of our overall screening assessment, denoting the stage at which the programs or projects were screened out and providing a high-level rationale for the decision.

Table 7: NWS Pre-Screening Framework Results Summary

Program Name	Project Name	Outcome	Stage Screened out	Rationale in Brief
Externally Initiated Plant Relocations	N/A	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
Customer Connections	N/A	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
System Expansion	N/A	Screened Out	2.1 Need Primacy Fit Test	NWS cannot fully address Customer Service Requests alone
Substation Renewal	Station Deficiencies	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	DC System Replacement	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Shuter	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Catharine	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.

Program Name	Project Name	Outcome	Stage Screened out	Rationale in Brief
	Fairport	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Edgehill	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Cavan South	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Garden	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Bigelow	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Crandell	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Riverside	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Uxbridge East	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Town Centre	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Herchimer	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Cascade	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Westney Heights	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Uxbridge West	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
Underground System Renewal	N/A	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
Overhead System Renewal	N/A	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
Reactive Capital	N/A	Screened Out	2.1 Need Primacy Fit Test	NWS cannot fully address Failure alone
Substation Growth	Uxbridge North MS	Screened Out	2.2 Need Velocity Fit Test	Need Materializes Before Utility Specific Threshold

Program Name	Project Name	Outcome	Stage Screened out	Rationale in Brief
	Foster MS	Screened Out	2.1 Need Primacy Fit Test	NWS not a Viable Solution to Address System Voltage Conversion Needs
	Mobile Station MS	Screened Out	2.1 Need Primacy Fit Test	NWS not a Viable Solution to Address Station Construction Support Needs
	Port Hope MS	Screened Out	2.1 Need Primacy Fit Test	NWS not a Viable Solution to Address System Voltage Conversion Needs
	Bradshaw MS	Advanced to BCA	N/A	NWS may be a Viable Solution Subject to results Economic Assessment via BCA
	Winchester West MS-Stage 1	Screened Out	2.2 Need Velocity Fit Test	Need Materializes Before Utility Specific Threshold
	Winchester West MS-Stage 2	Screened Out	2.3 Event Frequency Fit Test	NWS not a Viable Solution to Address Baseload Needs
	Transformer Station in North Whitby	Screened Out	2.3 Event Frequency Fit Test	NWS not a Viable Solution to Address Baseload Needs
Grid Enhancements	Distribution Modernization	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
	Station Modernization	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
	Distribution Capacity and Reliability Enhancements-Feeder Capacity	Advanced to BCA	N/A	NWS may be a Viable Solution Subject to results Economic Assessment via BCA
	Distribution Capacity and Reliability Enhancements-Undersized Conductors	Advanced to BCA	N/A	NWS may be a Viable Solution Subject to results Economic Assessment via BCA
	Distribution Capacity and Reliability Enhancements-Animal Guards	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Distribution Capacity and Reliability Enhancements-Lightning Arrestors	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
	Station Upgrades	Screened Out	1.Technical Fit Test	Lack of Technical Properties fit.
Voltage & System Conversion	Port Hope	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.

Program Name	Project Name	Outcome	Stage Screened out	Rationale in Brief
	Belleville	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.
	Pickering	Screened Out	1.Technical Fit Test	No expected impact on functional properties from NWS.

3.1. Recommendations and Next Steps

1. Perform the Benefit-Cost Analysis for the Bradshaw MS and Distribution Capacity and Reliability Enhancement Project

The application of the NWS Pre-Screening Framework to Elexicon's 2027-2031 DSP effectively identified candidate projects for further BCA assessment. Of the 41 programs / projects reviewed, 38 were screened out based on the framework criteria, primarily due to the lack of technical and functional fit, timing of need, or the underlying load profile characteristics. The remaining projects demonstrated preliminary alignment with NWS and warrant deeper evaluation of the economic competitiveness against traditional solutions.

In accordance with the *NWS Guidelines*, Elexicon should now conduct a detailed BCA for the projects that passed the pre-screening stage. The BCA should compare the full lifecycle costs and benefits of NWS options against traditional solutions, including avoided capital costs, operational savings, reliability impacts, and non-energy benefits. As we discussed above, we also recommend that Elexicon use the opportunity of BCA work to define a minimal viable technology and process stack for supporting NWS planning and operation.

2. Conduct WS Pre-Screening Activities on a Regular Basis

Consistent with the recommendation in our main report, we suggest that Elexicon conduct NWS pre-screening work on a regular basis – preferably annually. This could be done in conjunction with Elexicon's annual capacity planning / load research efforts. We expect that performing this analysis more frequently will result in greater adoption and increased input data sourcing and processing efficiency. Given the pace of technological evolution and the dynamic nature of Ontario's electricity policy landscape, annual review cadence will help maintain currency and serve as a reminder to assess the progress made in other relevant operating or planning areas.

3.2. Conclusion

CRA thanks Elexicon for the opportunity to stress test its proposed NWS pre-screening framework on its comprehensive multi-year investment portfolio. Overall, we believe that the pre-screening process that we recommend has proven to be reasonably effective and efficient at isolating the needs and conventional projects where NWS can present a viable alternative. It is our hope that Elexicon finds our conclusions helpful in advancing their near-term and strategic objectives in the area of distributed energy resources management.